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

FORM 10-K

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

For the fiscal year ended December 31, 2019
or

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

For the transition period from ______________________ to ______________________

Commission file number: 1-33615

Concho Resources Inc.
(Exact name of registrant as specified in its charter)

Delaware	**76-0818600**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Concho Center
600 West Illinois Avenue

Midland Texas	**79701**
(Address of principal executive offices)	(Zip Code)

(432) 683-7443
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $0.001 par value	**CXO**	**New York Stock Exchange**

Securities Registered Pursuant to Section 12(g) of the Act: **None**

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

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

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
Emerging growth company	☐		

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter:	$	20,479,372,863
Number of shares of the registrant's common stock outstanding as of February 14, 2020		196,705,121

Documents Incorporated by Reference

Portions of the registrant's definitive proxy statement for its 2020 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2019, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2019.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements and information contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our future financial position, operations, performance, business strategy, oil and natural gas reserves, drilling program, production, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of regulation and disputes. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "will," "goal" or other words that convey future events, expectations or possible outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events and their potential effect on us. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by any forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, whether as a result of new information, future events or otherwise, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in "Item 1A. Risk Factors" in this report, as well as those factors summarized below:

- declines in, the sustained depression of, or increased volatility in the prices we receive for our oil and natural gas, or increases in the differential between index oil or natural gas prices and prices received;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation related to hydraulic fracturing and climate change;
- competition in the oil and natural gas industry;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil and natural gas and other processing and transportation considerations;
- drilling, completion and operating risks, including our ability to efficiently execute large-scale project development as we could experience delays, curtailments and other adverse impacts associated with well spacing and a high concentration of activity;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- risks related to the concentration of our operations in the Permian Basin of West Texas and Southeast New Mexico;
- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- uncertainty concerning our assumed or possible future results of operations;
- evolving cybersecurity risks, such as those involving unauthorized access or control, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions;
- environmental hazards, such as uncontrollable flows of oil, natural gas, saltwater, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- general economic and business conditions, either internationally or domestically;
- the costs and availability of equipment, resources, services and qualified personnel required to perform our drilling, completion and operating activities;
- risks associated with acquisitions such as increased expenses and integration efforts, failure to realize the expected benefits of the transaction and liabilities associated with acquired properties or businesses;
- risks related to ongoing expansion of our business, including the recruitment and retention of qualified personnel in the Permian Basin;
- the impact of current and potential changes to federal or state tax rules and regulations;
- potential financial losses or earnings reductions from our commodity price risk-management program;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our Credit Facility, as defined herein;
- the impact of potential changes in our credit ratings; and
- uncertainties about our ability to replace reserves and economically develop our current reserves.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and the price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

PART I

Item 1. Business

General

Concho Resources Inc., a Delaware corporation ("Concho," the "Company," "we," "us" and "our") incorporated in February 2006, is an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our operations are primarily focused in the Permian Basin of West Texas and Southeast New Mexico. The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, long reserve life, multiple producing horizons and significant recovery potential. Concho's legacy in the Permian Basin provides us a deep understanding of operating and geological trends, and we are actively developing our resource base utilizing long-lateral wells and multi-well pad locations.

Business and Properties

Our operations are focused in the Permian Basin, which underlies an area of West Texas and Southeast New Mexico approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from less than 1,000 feet to over 25,000 feet. At December 31, 2019, our 1,002 MMBoe total estimated proved reserves were approximately 74 percent proved developed, as compared to proved developed reserves of approximately 69 percent of total estimated proved reserves of 1,187 MMBoe at December 31, 2018. Our total estimated proved reserves at December 31, 2019 consisted of approximately 62 percent oil and 38 percent natural gas.

We have one operating segment and one reporting unit, which is oil and natural gas development, exploration and production. All of our operations are conducted in one geographic area of the United States.

On July 19, 2018, we completed the acquisition of RSP Permian, Inc. ("RSP") through an all-stock transaction (the "RSP Acquisition"). RSP was an independent oil and natural gas company engaged in the acquisition, exploration, development and production of oil and natural gas reserves in the Permian Basin. The vast majority of RSP's acreage was located on large, contiguous acreage blocks in the core of the Midland Basin and the Delaware Basin. The acquisition added approximately 92,000 net acres to our asset portfolio.

The following table summarizes our drilling activity during the periods indicated:

	Years Ended December 31,		
	2019	2018	2017
Gross wells	454	428	311
Net wells	257	266	197
Percent of gross wells drilled horizontally	100%	100%	100%
Percent of gross wells:			
Productive	55%	44%	61%
Unsuccessful	—%	—%	1%
Awaiting completion at year end	45%	56%	38%
	100%	100%	100%

Summary of Operating Areas

The following is a summary of information regarding our operating areas:

	December 31, 2019					
Operating Areas	Estimated Proved Reserves (MMBoe)	% Oil	% Proved Developed	Total Gross Acreage (in thousands)	Total Net Acreage (in thousands)	2019 Average Daily Production (MBoe per Day)
Delaware Basin	556	61%	76%	524	352	217
Midland Basin	446	63%	73%	285	197	114
Total	1,002	62%	74%	809	549	331

Operating areas

Our operations are focused in the Delaware Basin and the Midland Basin, within the greater Permian Basin. Our development in both areas includes large-scale, full-field development to maximize resource recovery and program economics while optimizing well spacing, landing intervals, lateral length and completion techniques.

Delaware Basin. At December 31, 2019, we had estimated proved reserves in this area of 556 MMBoe, representing 55 percent of our total proved reserves. During the year ended December 31, 2019, we commenced drilling or participated in the drilling of 299 (148 net) wells in this area, and we completed 294 (176 net) wells that are producing.

Our activity in 2019 was centered mostly on continued development of our assets, with an emphasis on multi-well pad sites and extended lateral lengths to develop multiple producing formations. We primarily target the Avalon, Bone Spring and Wolfcamp formations, which generally range from 6,500 feet to 13,500 feet.

Midland Basin. At December 31, 2019, we had estimated proved reserves in this area of 446 MMBoe, representing 45 percent of our total proved reserves. During the year ended December 31, 2019, we commenced drilling or participated in the drilling of 155 (109 net) wells in this area, and we completed 185 (131 net) wells that are producing.

Our primary objectives in the Midland Basin area are the Spraberry and Wolfcamp formations, which generally range from 7,500 feet to 11,500 feet. We are developing these formations with horizontal drilling, utilizing multi-well pad sites and extended lateral development.

Drilling Activities

The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed in the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	151	124	114	80	96	76
Dry	—	—	—	—	1	1
Exploratory wells:						
Productive	328	183	236	124	209	112
Dry	3	2	1	1	3	3
Total wells:						
Productive	479	307	350	204	305	188
Dry (a)	3	2	1	1	4	4
Total	482	309	351	205	309	192

(a) The dry hole category includes 2 (1 net) wells and 1 (1 net) well that were unsuccessful due to mechanical issues for the years ended December 31, 2019 and 2018, respectively. Additionally, the dry hole category includes 1 (1 net) well that was incapable of producing hydrocarbons in economic quantities for the year ended December 31, 2019.

Present activities. The following table sets forth information about wells for which drilling was in-progress or are pending completion at December 31, 2019, which are not included in the above table:

	Drilling In-Progress		Pending Completion	
	Gross	Net	Gross	Net
Development and exploratory wells	34	21	157	95

Our Production, Prices and Expenses

The following table sets forth a summary of our production and operating data for the years ended December 31, 2019, 2018 and 2017. The actual historical data in this table excludes results from the RSP Acquisition for periods prior to July 19, 2018. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2019	**2018**	**2017**
Production and operating data:			
Net production volumes:			
Oil (MBbl)	76,369	61,251	43,472
Natural gas (MMcf)	266,865	208,326	161,089
Total (MBoe)	120,847	95,972	70,320
Average daily production volumes:			
Oil (Bbl)	209,230	167,811	119,101
Natural gas (Mcf)	731,137	570,756	441,340
Total (Boe)	331,086	262,937	192,658
Average prices per unit: (a)			
Oil, without derivatives (Bbl)	$ 54.03	$ 56.22	$ 48.13
Oil, with derivatives (Bbl) (b)	$ 52.35	$ 52.73	$ 49.93
Natural gas, without derivatives (Mcf)	$ 1.74	$ 3.40	$ 3.07
Natural gas, with derivatives (Mcf) (b)	$ 1.86	$ 3.37	$ 3.06
Total, without derivatives (Boe)	$ 38.00	$ 43.25	$ 36.78
Total, with derivatives (Boe) (b)	$ 37.19	$ 40.98	$ 37.88
Operating costs and expenses per Boe: (a)			
Oil and natural gas production	$ 5.93	$ 6.14	$ 5.80
Production and ad valorem taxes	$ 2.89	$ 3.19	$ 2.82
Gathering, processing and transportation	$ 0.96	$ 0.58	$ —
Depreciation, depletion and amortization	$ 16.25	$ 15.41	$ 16.29
General and administrative	$ 2.69	$ 3.25	$ 3.46

(a) Per unit and per Boe amounts calculated using dollars and volumes rounded to thousands.

(b) Includes the effect of net cash receipts from (payments on) derivatives:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ (129)	$ (213)	$ 79
Natural gas derivatives	31	(5)	—
Total	$ (98)	$ (218)	$ 79

The presentation of average prices with derivatives is a result of including the net cash receipts from (payments on) commodity derivatives that are presented in our consolidated statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2019, 2018 and 2017. The change in gross and net wells for 2019 as compared to 2018 is primarily attributable to the New Mexico Shelf divestiture. See Note 5 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information. As of December 31, 2019, we did not have any wells with multiple completions. This table does not include wells in which we own a royalty interest only.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
December 31, 2019						
Operating Areas:						
Delaware Basin	1,991	574	2,565	1,216	279	1,495
Midland Basin	3,397	16	3,413	2,255	5	2,260
Other	—	3	3	—	—	—
Total	5,388	593	5,981	3,471	284	3,755
December 31, 2018						
Operating Areas:						
Delaware Basin	4,801	690	5,491	3,569	313	3,882
Midland Basin	3,770	13	3,783	2,437	4	2,441
Other	—	3	3	—	—	—
Total	8,571	706	9,277	6,006	317	6,323
December 31, 2017						
Operating Areas:						
Delaware Basin	4,801	586	5,387	3,469	274	3,743
Midland Basin	2,747	15	2,762	1,675	6	1,681
Other	—	3	3	—	—	—
Total	7,548	604	8,152	5,144	280	5,424

Marketing Arrangements

General. We market our oil and natural gas in accordance with standard energy industry practices. Through our marketing efforts we endeavor to obtain the combined highest netback and most secure market available at that time. In addition, marketing supports our operations group as it relates to the planning and preparation of future development activity so that available markets can be assessed and secured.

Oil. We generally sell production at the lease to third-party purchasers. We generally do not transport, refine or process the oil we produce. Most of our Delaware Basin production in New Mexico is connected to the Plains Pipeline, L.P. gathering system. This production is then primarily purchased by three different purchasers.

Most of our Delaware Basin production in Texas is connected to one of five different gathering systems. A significant portion of our Midland Basin production is on one of nine different gathering systems. The remaining portion of our production is sold via truck transport. We sell our produced oil under contracts using market-based pricing, which is adjusted for differentials based upon delivery location and oil quality.

Natural Gas. We consider all natural gas gathering, treating and processing service providers in the areas of our production and evaluate market options to obtain the best price reasonably available given the necessary operating conditions. We sell the majority of our natural gas under individually negotiated natural gas purchase contracts using market-based pricing. The majority of our natural gas is subject to long-term agreements that generally extend five to ten years from the effective date of the subject contract.

The majority of our natural gas is casing head gas, which is sold at the lease location under (i) percentage of proceeds processing contracts, (ii) fee-based contracts or (iii) a hybrid of percentage of proceeds and fee-based contracts. The purchasers generally gather our casinghead natural gas in the field where it is produced and then transport it via pipeline to natural gas processing plants where natural gas liquid products and residue gas are extracted and sold. Under our percentage of proceeds and hybrid percentage of proceeds and fee-based contracts, we receive a percentage of the value for the extracted liquids and the residue gas. Under our fee-based contracts, we receive natural gas liquids and residue gas value, less the fee component thereof, or are invoiced the fee component of the purchaser's service.

Delivery Commitments

Certain of our firm sales agreements for both oil and natural gas include delivery commitments. We believe our current production and reserves are sufficient to fulfill these delivery commitments. See Note 11 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for more information.

Our Principal Customers

We sell our oil and natural gas production principally to marketers and other purchasers that have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2019, revenues from oil and natural gas sales to Plains Marketing and Transportation, Inc. and Enterprise Crude Oil LLC accounted for approximately 17 percent and 10 percent of our total operating revenues, respectively. While the loss of either purchaser may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions. See Note 13 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

Competition

The oil and natural gas industry in the areas in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties. At higher commodity prices, we also face competition in contracting for drilling, pressure pumping and workover equipment and securing and retaining qualified personnel. Many of these competitors have financial, technical and personnel resources substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling, pressure pumping and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay drilling, workover and exploration activities and cause significant price increases. We are not experiencing material shortages at this time but are unable to predict the timing or duration of any such future shortages.

Working Capital

Based on current market conditions, we have maintained a stable liquidity position. Our principal source of liquidity is available borrowing capacity under our credit facility, as amended and restated (our “Credit Facility”). At December 31, 2019, we had a cash balance of $70 million and did not have any borrowings under our Credit Facility. Additionally, we had approximately $2.0 billion of unused commitments under our Credit Facility. Our primary needs for cash are development, exploration and acquisitions of oil and natural gas assets, payment of contractual obligations and working capital obligations. However, additional borrowings under our Credit Facility or the issuance of additional debt securities will require a greater portion of our cash flow from operations to be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions.

Applicable Laws and Regulations

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require notice to stakeholders of proposed and ongoing operations;
- require the installation of emission control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the production rate of oil and natural gas below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Violations and liabilities with respect to these laws and regulations could result in significant administrative, civil or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and leasehold acreage. Additionally, environmental laws and regulations are revised frequently, and any changes, including changes in implementation or interpretation, that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to regulatory guidance issued by the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Each state also has environmental cleanup laws analogous to CERCLA.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose storage, treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the “Clean Water Act”) and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including dredge and fill activities in regulated wetlands, is prohibited, except in accordance with the terms of a permit issued by the EPA, or, in some circumstances, the U.S. Army Corps of Engineers (the “Corps”), or an analogous state agency. In addition, spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. Further, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. On January 23, 2020, the EPA and the Corps issued the “Navigable Waters Protection Rule,” which narrows the scope of waters federally regulated under the Clean Water Act. The former regulation that had attempted to define the scope of the “Waters of the United States” (the “2015 Rule”) was repealed in 2019. Litigation over the “Navigable Water Protection Rule” and the repeal of the 2015 Rule are expected to continue. An expansion of the scope of the definition of jurisdictional waters subject to regulation under the Clean Water Act could increase our compliance costs.

Safe Drinking Water Act. Our oil and natural gas exploration and production operations generate produced water, drilling muds, and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations. The drilling and operation of these injection wells are regulated by the federal Safe Drinking Water Act (the “SDWA”). The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. Any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and would ultimately increase the cost of our operations, which costs could be significant. For example, in 2014 the Railroad Commission of Texas (the “RRC”) adopted additional permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase, and our ability to continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

Air emissions. The federal Clean Air Act (the “CAA”), and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. These and other laws and regulations may increase the costs of compliance for some facilities where we operate. Obtaining or renewing permits also has the potential to delay the development of our projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. These air emission rules have the potential to increase our compliance costs.

Climate change. In response to findings that emissions of carbon dioxide, methane and other “greenhouse gases” (“GHGs”) present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions resulting from the completion and workover operations of hydraulically fractured oil wells. Recent federal regulatory action with respect to climate change has focused on methane emissions. Both the EPA and the U.S. Bureau of Land Management (the “BLM”) finalized rules in 2016 that limit methane emissions from upstream oil and natural gas exploration and production operations. Increased regulation of methane and other GHGs have the potential to result in increased compliance costs and, consequently, adversely affect our operations. In addition, in August 2019, the EPA issued the Affordable Clean Energy rule (“ACE”) that designates heat rate improvement, or efficiency improvement, as the best system of emissions reduction for carbon dioxide from existing coal-fired electric utility generating units.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established rules aimed at reducing GHG emissions, including GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In addition, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Reduced demand for the oil and natural gas that we produce could also have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. It should also be noted that some scientists have concluded that increasing concentrations of GHGs in the earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Hydraulic fracturing*.* Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing as part of our operations. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel and issued guidance in February 2014 governing such activities. The EPA has also issued final regulations under the CAA establishing performance standards, including standards for the capture of volatile organic compounds (“VOCs”) and methane released during hydraulic fracturing (although the EPA has temporarily suspended or delayed compliance with certain of these standards as they undergo an administrative review); an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico and Texas have adopted hydraulic fracturing fluid disclosure requirements, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition, local governments have also taken steps to regulate hydraulic fracturing, including imposing restrictions or moratoria on oil and natural gas activities occurring within their boundaries. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our well control, general liability and excess liability insurance policies may cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies. If new laws or regulations significantly restrict hydraulic fracturing activities or impose burdens on new permitting or operating requirements, our ability to utilize hydraulic fracturing may be curtailed, and this may in turn reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Operations on Federal Lands. We currently operate on federal lands under the jurisdiction of the BLM. Permitting for oil and natural gas activities on federal lands can take significantly longer than the state permitting process. Delays in obtaining permits necessary can disrupt our operations and have an adverse effect on our business. In November 2016, the BLM finalized rules that restrict methane emissions from oil and natural gas activities on federal lands by limiting venting and flaring of natural gas from wells and other equipment. The final rule also requires operators to pay royalties to the BLM on flared gas from wells already connected to gas capture infrastructure, and allows the agency to set royalty rates at or above 12.5 percent of the value of production. These rules could result in increased compliance costs for our operations, which in turn could have an adverse effect on our business and results of operations.

Endangered species. The federal Endangered Species Act (the “ESA”) and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete drilling and developmental operations and could adversely affect our future production from those areas. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers’ performance of operations.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (“NEPA”). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or even halt development of some of our oil and natural gas projects.

OSHA and other laws and regulations. We are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety.

We are not aware of any existing environmental issues, claims or regulations that will require us to incur material capital expenditures during 2020, and we did not incur material capital expenditures relating to environmental issues, claims or regulations during 2019. However, we cannot assure that the passage or application of more stringent laws or regulations or the application of existing laws in the future will not require us to incur material capital expenditures or have a material adverse effect on our financial position or results of operations.

Our Employees

Our corporate headquarters are located at One Concho Center, 600 West Illinois Avenue, Midland, Texas 79701 and have administrative offices in both Houston, Texas and Dallas, Texas. We also maintain various field offices in Texas and New Mexico. At December 31, 2019, we had 1,453 employees, 511 of whom were employed in field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the U.S. Securities and Exchange Commission (the "SEC") under the Exchange Act. The public can obtain any documents that we file with the SEC at *www.sec.gov*. We also make available free of charge through our website, *www.concho.com*, our reports that we file or furnish with the SEC as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Non-GAAP Financial Measures and Reconciliations

Reconciliation of Standardized Measure to PV-10

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the GAAP standardized measure of discounted future net cash flows to PV-10 (non-GAAP) at December 31, 2019, 2018 and 2017:

	December 31,		
(in millions)	**2019**	**2018**	**2017**
Standardized measure of discounted future net cash flows	$ 9,583	$ 15,555	$ 7,478
Present value of future income taxes discounted at 10%	1,000	2,392	1,001
PV-10	$ 10,583	$ 17,947	$ 8,479

Reconciliation of Net Income (Loss) to Adjusted EBITDAX

Adjusted EBITDAX (as defined below) is presented herein and reconciled from the GAAP measure of net income (loss) because of its wide acceptance by the investment community as a financial indicator.

We define adjusted EBITDAX as net income (loss), plus (1) exploration and abandonments, (2) depreciation, depletion and amortization, (3) accretion of discount on asset retirement obligations, (4) impairments of long-lived assets, (5) impairments of goodwill, (6) non-cash stock-based compensation, (7) (gain) loss on derivatives, (8) net cash receipts from (payments on) derivatives, (9) (gain) loss on disposition of assets and other, (10) interest expense, (11) loss on extinguishment of debt, (12) gain on equity method investments, (13) RSP transaction costs and (14) income tax expense (benefit). Adjusted EBITDAX is not a measure of net income (loss) or cash flows as determined by GAAP.

Our adjusted EBITDAX measure provides additional information that may be used to better understand our operations. Adjusted EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income (loss) as an indicator of operating performance. Certain items excluded from adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. Adjusted EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that adjusted EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements. For example, adjusted EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of our assets and our Company without regard to capital structure or historical cost basis. Adjusted EBITDAX, as used herein, may not be comparable to similarly titled measures reported by other companies.

The following table provides a reconciliation of the GAAP measure of net income (loss) to adjusted EBITDAX (non-GAAP) for the periods indicated:

	Years Ended December 31,				
(in millions)	**2019**	**2018**	**2017**	**2016**	**2015**
Net income (loss)	$ (705)	$ 2,286	$ 956	$ (1,462)	$ 66
Exploration and abandonments	201	65	59	77	59
Depreciation, depletion and amortization	1,964	1,478	1,146	1,167	1,223
Accretion of discount on asset retirement obligations	10	10	8	7	8
Impairments of long-lived assets	890	—	—	1,525	61
Impairments of goodwill	282	—	—	—	—
Non-cash stock-based compensation	85	82	60	59	63
(Gain) loss on derivatives	895	(832)	126	369	(700)
Net cash receipts from (payments on) derivatives	(98)	(218)	79	625	633
(Gain) loss on disposition of assets and other	(456)	(800)	(678)	(118)	54
Interest expense	185	149	146	204	215
Loss on extinguishment of debt	—	—	66	56	—
Gain on equity method investments	(17)	(103)	—	—	—
RSP transaction costs	—	32	—	—	—
Income tax expense (benefit)	(154)	603	(75)	(876)	31
Adjusted EBITDAX	$ 3,082	$ 2,752	$ 1,893	$ 1,633	$ 1,713

Item 1A. Risk Factors

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC before investing in our securities. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our securities could decline and you could lose all or part of your investment.

Risks Related to Our Business

Oil and natural gas prices are volatile. A decline in oil and natural gas prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil and natural gas prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices and levels of production for oil and natural gas are subject to a variety of factors beyond our control, including:

- the overall global demand for oil and natural gas;
- the overall global supply of oil and natural gas;
- the overall North American oil and natural gas supply and demand fundamentals, including:
  - the U.S. economy,
  - weather conditions, and
  - liquefied natural gas ("LNG") deliveries to and exports from the United States;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities, as well as the availability of commodity processing and gathering and refining capacity;
- risks related to the concentration of our operations in the Permian Basin of West Texas and Southeast New Mexico and the level of commodity inventory in the Permian Basin;
- economic conditions worldwide, including adverse conditions driven by political, health or weather events;
- the level of global crude oil, crude oil products and LNG inventories;
- volatility and trading patterns in the commodity-futures markets;
- political and economic developments in oil and natural gas producing regions, including Africa, South America and the Middle East;
- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to influence global oil supply levels;
- changes in trade relations and policies, including the imposition of tariffs by the United States or China;
- technological advances or social attitudes and policies affecting energy consumption and sources of energy supply;
- activism or activities by non-governmental organizations to limit certain sources of capital for the energy sector or restrict the exploration, development and production of oil and gas;
- the effect of energy conservation efforts, alternative fuel requirements and climate change-related initiatives;
- additional restrictions on the exploration, development and production of oil, natural gas and natural gas liquids so as to materially reduce emissions of carbon dioxide and methane GHGs;
- political and economic events that directly or indirectly impact the relative strength or weakness of the U.S. dollar, on which oil prices are benchmarked globally, against foreign currencies;
- domestic and foreign governmental regulations, including limits on the United States' ability to export crude oil, and taxation;

- the cost and availability of products and personnel needed for us to produce oil and natural gas, including rigs, crews, sand, water and water disposal;
- the quality of the oil we produce; and
- the price, availability and acceptance of alternative fuels.

Furthermore, oil and natural gas prices continued to be volatile in 2019. For example, NYMEX oil prices in 2019 ranged from a high of $66.30 to a low of $45.41 per Bbl and the NYMEX natural gas prices in 2019 ranged from a high of $3.59 to a low of $2.07 per MMBtu.

Declines in oil and natural gas prices would not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically. This in turn would lower the amount of oil and natural gas reserves we could recognize and, as a result, could have a material adverse effect on our financial condition and results of operations. If the oil and natural gas industry experiences significant price declines for a sustained period, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can adversely affect the value of our securities.

Approximately 26 percent of our total estimated proved reserves at December 31, 2019 were undeveloped, and those reserves may not ultimately be developed.

At December 31, 2019, approximately 26 percent of our total estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserves data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Our reserve report at December 31, 2019 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $2.4 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC’s reserve rules, because proved undeveloped reserves may be recognized only if they relate to wells planned to be drilled within five years of the date of their initial recognition, we may be required to write-off any proved undeveloped reserves that are not developed within this five-year time frame. For example, as of December 31, 2019, we wrote-off approximately 28 MMBoe of proved undeveloped reserves primarily because we no longer expect to develop these reserves within five years of the date of their initial recognition.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could cause our costs to increase or production volumes to decrease, which would reduce our cash flows.

Our future financial condition and results of operations depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- reductions in oil and natural gas prices;
- delays and costs of drilling wells on lands subject to complex development terms and circumstances;
- oil or natural gas gathering, transportation and processing availability restrictions or limitations;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- adverse weather conditions and natural disasters;
- environmental hazards, such as natural gas leaks, hydrogen sulfide (“H2S”) treating capacity constraints, oil and produced water spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- surface access restrictions;

- failure to obtain regulatory and third-party approvals;
- actions by third-party operators of our properties, including offsetting fracturing stimulation operations;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining sand or water for hydraulic fracturing activities;
- loss of title or other title related issues;
- limitations in the market for oil and natural gas; and
- limited availability of financing at acceptable terms.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, as well as significant liabilities. Moreover, certain of these events could result in environmental pollution and impact to third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries, death or significant damage to property and natural resources.

In addition, the results of our exploratory drilling, including well spacing tests, in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Multi-well pad drilling and project development may result in volatility in our operating results.

We utilize multi-well pad drilling and project development where practical. Project development may involve more than one multi-well pad being drilled and completed at one time in a relatively confined area. Wells drilled on a pad or in a project may not be brought into production until all wells on the pad or project are drilled and completed. Problems affecting one pad or a single well could adversely affect production from all of the wells on the pad or in the entire project. As a result, multi-well pad drilling and project development can cause delays in the scheduled commencement of production, or interruptions in ongoing production. These delays or interruptions may cause declines or volatility in our operating results due to timing as well as declines in oil and natural gas prices. Further, any delay, reduction or curtailment of our development and producing operations, due to operational delays caused by multi-well pad drilling or project development, or otherwise, could result in the loss of acreage through lease expirations.

Additionally, infrastructure expansion, including more complex facilities and takeaway capacity, could become challenging in project development areas. Managing capital expenditures for infrastructure expansion could cause economic constraints when considering design capacity.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing.

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the risk of unintentional communication with other adjacent wells and the potential to reduce total recoverable reserves from the reservoir. If these risks materialize and negatively impact our results of operations relative to guidance or market expectations, and the research analysts who cover our Company may downgrade our common stock or change their recommendations or earnings or performance estimates, which may result in a decline in the market price of our common stock.

Prolonged decreases in our drilling program may require us to pay certain non-use fees or impact our ability to comply with certain contractual requirements.

In the event that oil prices decline for a sustained period, we may experience significant decreases in drilling activity. Due to the nature of our drilling programs and the oil and natural gas industry in general, we are a party to certain agreements that require us to meet various contractual obligations or require us to utilize a certain amount of goods or services, including, but not limited to, water commitments, throughput volume commitments, power commitments and drilling commitments. In the event that oil and natural gas prices decrease, and as a result continue to reduce the demand for drilling and production, this could lead to a decrease in our drilling activity and production levels, which could, in turn, require us to pay for unutilized goods or services or impact our ability to meet these contractual obligations, including drilling commitments that may result in lease expirations if unmet.

We may incur losses as a result of title defects in our oil and natural gas properties.

It is our practice to initially conduct only a cursory title review of the oil and natural gas properties on which we do not have proved reserves. To the extent title opinions or other investigations prior to our commencement of drilling operations reflect defects affecting such properties, we are typically responsible for curing any such defects at our expense. Additionally, the discovery of any such defects could delay or prohibit the commencement of drilling operations on the affected properties. These impacts and other potential losses resulting from title defects in our oil and natural gas properties could have a material adverse effect on our business, financial condition and results of operations.

Our operations are substantially dependent on the availability of water and our ability to dispose of produced water gathered from drilling and production activities. Restrictions on our ability to obtain water or dispose of produced water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. West Texas and Southeast New Mexico have experienced extreme drought conditions in the past and we cannot guarantee what conditions may occur in the future. Severe drought conditions can result in local water districts taking steps to restrict the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

In addition, we must dispose of the fluids produced from oil and natural gas production operations, including produced water, which we do directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern arises from recent seismic events near underground disposal wells that are used for the disposal by injection of produced water resulting from oil and natural gas activities. In March 2016, the United States Geological Survey identified Texas and Colorado as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells to assess any relationship between seismicity and the use of such wells. For example, in Texas, the RRC adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. States may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or by commercial disposal well vendors whom we may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal.

Any one or more of these developments may result in us or our vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require us or our vendors to shut down or curtail the injection into disposal wells, which events could have a material adverse effect on our business, financial condition and results of operations.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA’s Underground Injection Control Program and issued guidance in February 2014, governing such activities. The EPA has also issued: final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing (although the EPA has temporarily suspended or delayed compliance with certain of these standards as they undergo an administrative review); an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Moreover, in March 2015, the BLM issued a final rule that imposes requirements on hydraulic fracturing activities on federal and Indian lands, including new requirements relating to public disclosure, wellbore integrity and handling of flowback water. However, the BLM lacked authority to promulgate the rule. While that decision was on appeal, the BLM rescinded this rule in December 2017. In January 2018, the state of California and a coalition of environmental groups filed a lawsuit in the Northern District of California to challenge the BLM’s rescission of the 2015 rule. This litigation is ongoing and future implementation of the rule is uncertain at this time.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico and Texas have adopted hydraulic fracturing fluid disclosure requirements, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition, local governments have also taken steps to regulate hydraulic fracturing, including imposing restrictions or moratoria on oil and natural gas activities occurring within their boundaries. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements and could also result in permitting delays and potential cost increases. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Climate change legislation, regulations restricting emissions of "greenhouse gases" or legal or other action taken by public or private entities related to climate change could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions resulting from the completion and workover operations of hydraulically fractured oil wells. Recent federal regulatory action with respect to climate change has focused on methane emissions. These methane emission rules have the potential to increase our compliance costs. See "Item 1. Business—Applicable Laws and Regulations—Environmental, Health and Safety Matters" for additional information.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established rules aimed at reducing GHG emissions, including GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In the future, the United States may also choose to adhere to international agreements targeting GHG reductions.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and natural gas that we produce could also have the effect of lowering the value of our reserves. It should also be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors. The ultimate impact of GHG emissions-related agreements, legislation and measures on our company's financial performance is highly uncertain because the Company is unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance, excise and ad valorem taxes, development costs, gathering, processing and transportation costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data, and improvements or other changes in geological, geophysical and engineering evaluation methods may cause reserve estimates to change over time. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on the average previous twelve months first-of-month prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil and natural gas; and
- changes in governmental regulations or taxation.

Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. Therefore, the estimates of discounted future net cash flows in this report should not be construed as accurate estimates of the current market value of our proved reserves.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. At December 31, 2019, we did not have any debt outstanding under our Credit Facility (and total debt at December 31, 2019 of $4.0 billion), and we had approximately $2.0 billion of unused commitments under our Credit Facility. Expenditures for acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We incurred approximately $3.1 billion in acquisition, exploration and development costs during the year ended December 31, 2019. In February 2020, our board of directors approved our 2020 capital budget of up to $2.9 billion. We expect to spend between $2.6 billion and $2.8 billion on drilling and completion activity. We plan to spend approximately $2.4 billion over the next five years on future development costs associated with proved undeveloped reserves.

We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and, if necessary, through borrowings under our Credit Facility. However, our cash flow from operations and access to capital are subject to a number of variables, including:

- the volume of oil and natural gas we are able to produce from existing wells;
- our ability to transport our oil and natural gas to market;
- the prices at which our commodities are sold;
- the costs of producing oil and natural gas;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital;
- our ability to acquire, locate and produce new reserves; and
- the impact of potential changes in our credit ratings.

We may not generate expected cash flows and may have limited ability to obtain the capital necessary to sustain our operations at current or anticipated levels. A decline in cash flow from operations or our financing needs may require us to revise our capital program or alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our Credit Facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our Credit Facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our Credit Facility. If we desire to issue additional debt securities other than as expressly permitted under our Credit Facility, we will be required to seek the consent of the lenders in accordance with the requirements of our Credit Facility, which consent may be withheld by the lenders at their discretion. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

The failure to obtain additional financing could result in a curtailment of our operations relating to the development of our undeveloped acreage or the curtailment of acquisitions that may be favorable to us, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

A decline in general economic, business or industry conditions could have a material adverse effect on our results of operations.

A global economic downturn, particularly with respect to the U.S. economy or the oil and natural gas industry, and global financial and credit market disruptions reduce the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide, which can result in a slowdown in economic activity. Reduced worldwide demand for energy often results in lower commodity prices, which will reduce our cash flows and may affect our borrowing ability. If the economic climate in the United States or abroad deteriorates, we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of oil and natural gas that we can produce economically, which could ultimately decrease our net revenue and profitability. In addition, reduced worldwide demand for securities issued by oil and natural gas companies or depressed trading prices of the debt and equity securities of oil and natural gas companies generally may depress the market value of our securities or make it more difficult for us to raise capital.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated. Additional state taxes on oil and natural gas extraction may be imposed, as a result of future legislation.

In recent years, U.S. lawmakers have proposed certain significant changes to U.S. tax laws applicable to oil and natural gas companies. These changes include, but are not limited to: (i) the elimination of current deductions for intangible drilling and development costs; (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these changes were not included in the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act ("TCJA"), it is unclear whether any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes (or the imposition of, or increases in, production, severance or similar taxes) were to be enacted, as well as any similar changes in state, local or non-U.S. law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil and natural gas.

Our ability to use our existing net operating loss carryforwards or other tax attributes could be limited.

At December 31, 2019, we had approximately $2.6 billion of federal net operating loss (“NOL”) carryforwards available to offset against future taxable income. Of these NOL carryforwards, $1.5 billion were generated prior to the effective date of new limitations on utilization of NOLs imposed by the TCJA and are allowable as a deduction against 100 percent of taxable income in future years but will begin to expire in the tax year 2034. The remaining federal NOL of $1.1 billion is subject to an 80 percent limitation but has an indefinite carryforward life. Included in our $2.6 billion of federal NOL carryforwards is approximately $516 million net NOLs that we acquired as part of the RSP Acquisition. This acquired tax NOL, $40 million of research and development (“R&D”) credits and $38 million of interest expense limitation carryforwards (“tax attributes”) are subject to an annual limitation under Section 382 of the Internal Revenue Code of 1986, as amended (“Section 382”). However, based on the annual limitation amount, our acquired tax attributes are considered more likely than not to be utilized.

Utilization of any tax attribute depends on many factors, including our ability to generate future taxable income, which cannot be assured. In addition, Section 382 generally imposes an annual limitation on the amount of tax attributes that may be used to offset taxable income and tax liability when a corporation has undergone an “ownership change” (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least five percent of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change has occurred, or were to occur, utilization of all of our tax attributes, including those acquired from RSP, would be subject to an annual limitation under Section 382, determined by multiplying the value of our equity at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, and potentially increased for certain gains recognized within five years after the ownership change if we have a net built-in gain in our assets at the time of the ownership change. Any unused annual limitation may be carried over to later years. We do not believe that an ownership change has occurred as a result of our equity offerings or our issuance of shares in connection with various acquisitions. As such, Section 382 is not expected to limit our ability to utilize our NOL carryforward or any other tax attributes at December 31, 2019. Future ownership changes or future regulatory changes could limit our ability to utilize our tax attributes. To the extent we are not able to offset our future income with our NOLs or tax liability with tax credits, this could adversely affect our operating results and cash flows once we attain profitability.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We had approximately $4.0 billion of outstanding aggregate principal indebtedness at December 31, 2019. At December 31, 2019, commitments from our bank group were $2.0 billion, all of which was unused. We continue to review our existing indebtedness, and we may seek to repay, refinance, repurchase, redeem, exchange or otherwise terminate our indebtedness. If we do seek to refinance our existing indebtedness, there can be no guarantee that we would be able to execute the refinancing on favorable terms or at all.

As a result of our indebtedness, we use a portion of our cash flow to pay interest, which reduces the amount we have available to fund our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our Credit Facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense. Financial regulators are working to transition away from LIBOR as a reference rate for financial contracts by the end of 2021 and to develop benchmarks to replace LIBOR. Certain types of borrowings under our Credit Facility are derived from the LIBOR reference rate. Our Credit Facility agreement includes general provisions governing the establishment of an alternate rate of interest to the LIBOR-based rate that gives consideration to the then prevailing market convention for determining a rate of interest for comparable syndicated loans. At this time, the impact on the Company's borrowing costs, if any, under an alternative reference rate scenario is uncertain.

We may incur substantially more debt in the future. Our Credit Facility and the indentures governing our senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures.

Any increase in our level of indebtedness could have adverse effects on our financial condition and results of operations, including:

- imposing additional cash requirements on us in order to support interest payments, which reduces the amount we have available to fund our operations and other business activities;

- increasing the risk that we may default on our debt obligations;
- increasing our vulnerability to adverse changes in general economic and industry conditions, economic downturns and adverse developments in our business;
- limiting our ability to sell assets, engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes;
- limiting our flexibility in planning for or reacting to changes in our business and the industry in which we operate; and
- increasing our exposure to a rise in interest rates, which will generate greater interest expense.

Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance, which is affected by general economic conditions and financial, business and other factors, many of which are out of our control.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest, if any, on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the agreements governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders under our Credit Facility could elect to terminate their commitments thereunder and cease making further loans; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers under our Credit Facility to avoid being in default. If we breach our covenants under our Credit Facility and cannot obtain a waiver from the required lenders, we would be in default under our Credit Facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt credit ratings from S&P Global Ratings ("S&P"), Moody's Investors Service, Inc. ("Moody's") and Fitch Ratings ("Fitch"), which are subject to regular reviews. In determining our ratings, the agencies consider a number of qualitative and quantitative factors including, but not limited to: the industry in which we operate, production growth opportunities, liquidity, debt levels and asset and reserve mix.

A downgrade in our credit ratings could (i) negatively impact our costs of capital and our ability to effectively execute aspects of our strategy, (ii) affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt and (iii) negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing. In September 2017, we elected to enter into an Investment Grade Period under our Credit Facility, as defined in Note 10 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data," which had the effect of releasing all collateral formerly securing our Credit Facility. If we are unable to maintain credit ratings of "Ba2" or better from Moody's and "BB" or better from S&P, the Investment Grade Period will automatically terminate and cause our Credit Facility to once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

As of the filing of this report, no additional changes in our credit ratings have occurred; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, occupational health and safety requirements applicable to our oil and natural gas exploration, development and production, and related saltwater disposal activities or the activities of our suppliers of critical materials and services. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment (including wildlife and natural resources), occupational health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability for a variety of environmental costs may be imposed on us under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. Costs stemming from environmental remediation obligations could be significant and adversely affect our financial condition and results of operations. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. No assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities or result in a material increase in the costs of production, development, exploration or processing operations. If we are not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

Our producing properties are concentrated in the Permian Basin of West Texas and Southeast New Mexico, making us vulnerable to risks associated with operating in one major geographic area. In addition, substantially all of our proved reserves are attributable to this area.

Our producing properties are geographically concentrated in the Permian Basin of West Texas and Southeast New Mexico. At December 31, 2019, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this geographic concentration, we are exposed to the impact of regional supply and demand factors; delays or interruptions of production from wells in this area caused by governmental regulation; processing or transportation capacity constraints, including potential pipeline capacity constraints in the Permian Basin; market limitations; severe weather events; water shortages or other drought related conditions; or interruption of the processing or transportation of oil or natural gas.

In addition to the geographic concentration of our producing properties described above, at December 31, 2019, approximately: (i) 55 percent of our proved reserves were attributable to the Delaware Basin that primarily targets the Avalon, Bone Spring and Wolfcamp formations; and (iii) 45 percent of our proved reserves were attributable to the Midland Basin that primarily targets the Spraberry and Wolfcamp formations. This concentration of assets exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We periodically assess our unproved oil and natural gas properties for impairment and could be required to recognize non-cash charges to earnings of future periods.

At December 31, 2019, we carried unproved property costs of $5.9 billion. GAAP requires periodic assessment of these costs on a project-by-project basis. Our assessment considers:

- future drilling and exploration plans;
- results of exploration activities;
- commodity price outlooks;
- planned future sales; and
- expiration of all or a portion of the projects, contracts and permits relevant to such projects.

Based on our assessments, we may determine that we are unable to fully recover the cost invested in each project, and we will recognize non-cash charges to earnings in future periods if such determination is made. For the years ended December 31, 2019 and 2018, we recorded $147 million and $35 million, respectively, of leasehold abandonments primarily related to expiring acreage and acreage where we had no future plans to drill, which is included in exploration and abandonments expense in our consolidated statements of operations.

We periodically evaluate our goodwill for impairment and could be required to recognize non-cash charges to earnings of future periods.

At December 31, 2019, we had goodwill of approximately $1.9 billion. We assess goodwill for impairment as of July 1 of each year or whenever circumstances indicate that the carrying value of our business may be impaired. If the book value of our reporting unit exceeds the estimated fair value of the reporting unit, an impairment charge will occur, which would negatively impact our results of operations and net worth. We performed an impairment test at December 31, 2019 due to a decline in our fair value during the second half of 2019 and recorded a $201 million impairment charge. See Note 2 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information.

Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in our having to make substantial downward adjustments to the value of our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. The primary factors that may affect management's estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred. We recorded impairment charges of $890 million in 2019. We did not incur an impairment charge in 2018 or 2017. See Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Our commodity price risk management program may cause us to forego additional future profits or result in us making cash payments to our counterparties.

To reduce our exposure to changes in the prices of commodities, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in commodity prices in some circumstances, including the following:

- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties;
- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or
- the counterparty to a commodity price risk management contract may default on its contractual obligations to us.

Our commodity price risk management activities could have the effect of reducing our net income and the value of our securities. At December 31, 2019, we had a net derivative liability of $102 million. An average increase in the commodity price of $5.00 per barrel of oil and $0.50 per MMBtu of natural gas from the commodity price at December 31, 2019 would have resulted in an increase in our net liability of approximately $451 million. We may continue to incur significant gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

Our actual production could differ materially from our forecasts.

From time to time, we provide forecasts of expected quantities of future oil and gas production and other financial and operating results. These forecasts are based on a number of estimates and assumptions. Production forecasts, specifically, are based on assumptions such as:

- expectations of production from existing wells and future drilling activity;
- the absence of facility or equipment malfunctions;
- the absence of adverse weather effects;
- expectations of commodity prices, which could experience significant volatility;
- expected well costs; and
- the assumed effects of regulation by governmental agencies, which could make certain drilling activities or production uneconomical.

Should any of these assumptions prove inaccurate, or should our development plans change, actual production could be materially and adversely affected. Failure to meet operating or financial forecasts and expectations, whether published by us or market participants, could adversely impact the trading price of our common stock.

Our identified inventory of drilling locations and recompletion opportunities are scheduled over several future years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified and scheduled the drilling of certain locations as an estimation of our future multi-year development activities on our existing acreage. These identified locations represent a significant part of our development and growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including those described elsewhere in these risk factors. Because of these and other potential uncertainties, we may never drill the potential locations we have identified or produce oil or natural gas from these or any other potential locations. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, reserves, revenues and results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our securities.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our securities and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production or replace our declining production with new production. We may not be able to develop, exploit, find or acquire sufficient additional reserves or replace our current and future production.

The Standardized Measure and PV-10 of our estimated reserves are not accurate estimates of the current fair value of our estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Our non-GAAP financial measure, PV-10, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure and PV-10 included in this report should not be construed as accurate estimates of the current fair value of our proved reserves.

Our reserve estimates and our computation of future net cash flows at December 31, 2019 are based on SEC pricing of (i) $52.19 per Bbl WTI posted oil price and (ii) $2.58 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property. If average oil prices were $5.00 per barrel lower than the average price we used, our PV-10 at December 31, 2019 would have decreased from $10.6 billion to $9.2 billion. If average natural gas prices were $0.50 per MMBtu lower than the average price we used, our PV-10 at December 31, 2019 would have decreased from $10.6 billion to $10.2 billion. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

We may be unable to make attractive acquisitions or successfully integrate acquired companies or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

One aspect of our business strategy calls for acquisitions of businesses or assets that complement or expand our current business. We may not be able to identify attractive acquisition opportunities, including acreage trades. Even if we do identify attractive candidates, pursuing such acquisitions may be distracting to management and costly to the Company. We may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our Credit Facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or business combination transactions. Our Credit Facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets. If we desire to engage in an acquisition that is otherwise prohibited by our Credit Facility or the indentures governing our senior notes, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of our Credit Facility or the indentures, which consent may be withheld by the lenders under our Credit Facility or such holders of senior notes at their sole discretion.

If we acquire another business or assets, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Any acquisition we complete is subject to substantial risks that could adversely affect our business, including the risk that our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.

We obtained a significant portion of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect that acquisitions, including acreage trades, will continue to contribute to our future growth. In connection with these and potential future acquisitions, we are often only able to perform limited due diligence. The success of any acquisition involves potential risks, including among other things:

- the inability to estimate accurately the costs to develop the reserves, recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;
- the assumption of unknown liabilities, including environmental liabilities, and losses or costs for which we are not indemnified or for which the indemnity we receive is inadequate;
- the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions;
- the diversion of management's attention from other business concerns; and
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact, and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties that we believe to be generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for preclosing liabilities, including environmental liabilities, but we generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, even when we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic labor shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher commodity prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases would decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our exploration and development drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. Drilling for oil and natural gas often involves unprofitable results, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, saltwater, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- blowouts, cratering, fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- damage to and destruction of property and equipment;
- damage to natural resources due to underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- regulatory investigations and penalties;
- loss of well location, acreage, expected production and related reserves;
- suspension or delay of our operations;
- substantial liability claims; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable, and we do not insure for business interruption of the loss of a well. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Some of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost and other challenges to attract and retain qualified personnel may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas, secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas processing or transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas, the proximity of reserves to pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering, storage and transportation systems, pipelines and processing facilities owned and operated by third parties. Throughout 2018 and 2019, concerns emerged that Permian oil and natural gas supply would exceed pipeline capacity. Our ability to market our production may be impacted if such constraints continue or become worse in the future. Our failure to obtain such services on acceptable terms or the failure of counterparties to perform under certain of our transportation or marketing arrangements could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in or otherwise curtail production from wells due to lack of a market or inadequacy or unavailability of oil or natural gas pipeline or gathering, storage, transportation or processing capacity and fractionation, refining or export facilities. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations or that may subject us to fines or penalties for any failure to comply.

Our oil and natural gas exploration, development and production, and related saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. If we fail to comply with the existing laws and regulations, we may incur additional costs, including fines and penalties, in order to come back into compliance. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted or if the government agencies responsible for enforcing certain existing laws and regulations applicable to us change their priorities or policies, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations. In addition, certain candidates for the 2020 presidential election have espoused as part of their overall campaign platform support for climate change regulation and bans on hydraulic fracturing that could materially impact our business. Approximately 20 percent of our acreage was located on federal lands at December 31, 2019. We cannot be certain of the impact of any new legislation at the state or federal level, but it could harm our business, operating results and financial condition. In addition, speculation regarding potential changes in the regulatory environment creates uncertainties that could lead to increased volatility in the market price of our common stock in the short term.

The implementation of derivatives legislation adopted by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”), became law on July 21, 2010 and requires the Commodity Futures Trading Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents; however, this initial position limits rule was vacated by the U.S. District Court for the District of Columbia in September 2012. The CFTC has subsequently issued proposals for new rules that would place position limits on certain core futures contracts and equivalent swap contracts for or linked to certain physical commodities, subject to certain exceptions for bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps subject to mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If our swaps do not qualify for the end-user exception from mandatory clearing, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or our ability to hedge may be impacted. The ultimate effect of the rules and any additional regulations on our business is uncertain at this time.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. While we are exempt from such requirements for the mandatory exchange of margin for uncleared swaps, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. Further, if we did not qualify for an exemption and were required to post collateral for our swaps, it could reduce our liquidity and cash available for capital expenditures and our ability to manage commodity price volatility and the volatility in cash flows.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. When fully implemented, the Act and any new regulations could increase the operational and transactional cost of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize and restructure our existing derivatives contracts, impact commodity prices and affect the number and/or creditworthiness of available counterparties. If we reduce our use of derivatives as a result of the Act and regulations implementing the Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The loss of our chief executive officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of our chief executive officer, Timothy A. Leach, and other officers and key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and natural gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Because we do not operate and therefore control the development of certain properties in which we own interests, we may not be able to produce economic quantities of oil and natural gas in a timely manner.

At December 31, 2019, approximately 5 percent of our proved reserves were attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on properties operated by others depend upon a number of factors that are beyond our control, including:

- the nature and timing of drilling and operational activities controlled by others;
- the timing and amount of the operators’ capital expenditures;
- the operators’ expertise and financial resources;
- the approval of other participants in such properties; and
- the selection and application of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted as we expect, we may be unable to increase our production or offset normal production declines or we will be required to write-off the reserves attributable to such properties, which may adversely affect our production, revenues and results of operations.

We do not control certain of the entities in which we own equity interests.

Certain of the entities in which we own equity interests are managed by their respective governing bodies, which we do not control. As a result, our ability to influence decisions with respect to the operation of such entities’ businesses and distributions from such entities is limited. Such ability varies depending on the amount of control we exercise under the applicable governing agreement, including with respect to cash distributions, capital calls, capital expenditures and the incurrence of additional indebtedness.

A terrorist or cyber attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts, cyber attacks and other armed conflicts involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our production and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of oil and natural gas production are destroyed or damaged. Additionally, as an oil and natural gas producer, we constantly face various cybersecurity threats, including threats to gain unauthorized access to sensitive information or to render data or systems unusable, and there can be no assurance that our implementation of various procedures and controls to monitor and mitigate security threats will be sufficient to prevent security breaches from occurring. Costs for insurance, recovery, remediation, potential litigation and other security measures may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our reliance on information technology, including those hosted by third parties, exposes us to cyber security risks that could affect our business, financial condition or reputation and increase compliance challenges.

We rely extensively on information technology systems, including internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information technology systems, as well as those of third parties we use in our operations, may be vulnerable to a variety of evolving cybersecurity risks, such as those involving unauthorized access or control, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions. These cybersecurity threat actors, whether internal or external to us, are becoming more sophisticated and coordinated in their attempts to access the company’s information technology systems and data, including the information technology systems of cloud providers and other third parties with whom the company conducts business.

Although we have implemented information technology controls and systems that are designed to protect information and mitigate the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the enhanced controls we have installed may be breached. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations which may include drilling, completion, production and corporate functions. A cyber attack involving our information systems and related infrastructure, or that of our business associates, could negatively impact our operations in a variety of ways, including, but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and natural gas resources;
- Data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;
- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;
- A cyber attack on third-party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;
- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- A cyber attack on our automated and surveillance systems could cause a loss in production and potential environmental hazards;
- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and
- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer’s, supplier’s or landowner’s data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

All of the above could negatively impact our operational and financial results. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. Additionally, the growth of cyber attacks has resulted in evolving legal and compliance matters which impose significant costs that are likely to increase over time.

Risks Related to Our Common Stock

Our certificate of incorporation, our bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, our bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;
- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 66 2/3 percent of the voting power of all outstanding voting stock;
- the prohibition of stockholder action by written consent; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

The payment of dividends will be at the discretion of our board of directors.

While the Company declared a quarterly dividend of $0.125 per share for each quarter in 2019 and intends to continue to pay a dividend in the future, the payment and amount of future dividend payments, if any, are subject to declaration by our board of directors. Such payments will depend on various factors, including actual results of operations, liquidity and financial condition, net cash provided by operating activities, restrictions imposed by applicable law, our taxable income, our operating expenses and other factors our board of directors deems relevant. Covenants contained in our Credit Agreement and the indentures governing our senior notes could limit the payment of dividends. The Company is under no obligation to make dividend payments on our common stock and may cease such payments at any time in the future.

The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities to raise cash for acquisitions. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our Company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

We cannot guarantee that our recently announced share repurchase program will be fully consummated or that such program will enhance the long-term value of our common stock.

In September 2019, we announced that our board of directors authorized the initiation of a $1.5 billion share repurchase program. We funded the 2019 repurchases primarily with proceeds from our New Mexico Shelf divestiture, which closed in November 2019. The Company is under no obligation to repurchase any specific dollar amount of common stock, and the repurchase program may be extended, suspended or discontinued at any time by our board of directors. As such, we cannot guarantee that this program will be fully consummated, or that such program will enhance the long-term value of our common stock. The extent to which we repurchase our common stock and the timing and funding of such repurchases are dependent upon a variety of factors, including market conditions, regulatory requirements and other corporate considerations, as determined by our management and board of directors. As of December 31, 2019, the Company had repurchased and retired 3,300,370 shares under the program at an aggregate cost of $250 million.

Item 1B. Unresolved Staff Comments

There are no unresolved staff comments.

Item 2. Properties

Our Oil and Natural Gas Reserves

The estimates of our proved reserves at December 31, 2019, all of which were located in the United States, were based on evaluations prepared by the independent petroleum engineering firms of Cawley, Gillespie & Associates, Inc. ("CGA") and Netherland, Sewell & Associates, Inc. ("NSAI") (collectively, our "external engineers"). Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the "FASB").

Internal controls. Our proved reserves are estimated at the property level by external engineers and compiled for reporting purposes by our corporate reservoir engineering staff. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interact with our internal staff of petroleum engineers, geoscience professionals and land professionals in each of our operating areas and with accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by members of our senior management and the health, safety, environment and reserves committee, a committee of our board of directors.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their preparation of our reserves.

Qualifications of responsible technical persons

Keith Corbett is our Senior Vice President of Corporate Engineering and Planning. In this role, Mr. Corbett is responsible for corporate reservoir engineering and strategic planning. Mr. Corbett joined the Company in 2005 as a Reservoir Engineer and has served in several Asset Manager roles and as an Operations Supervisor before he was appointed as Vice President of Texas (later, Vice President of Midland Basin) in 2015. Prior to joining Concho, Mr. Corbett held drilling, reservoir and production engineering positions at Pennzoil (later Devon Energy) and Stallion Energy. Mr. Corbett is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

Rick Morton joined the Company in 2011 and currently serves as the Corporate Engineering Director. Prior to joining the Company, Mr. Morton served as Division Acquisition Coordinator for EOG Resources, Inc. Mr. Morton was also previously employed by Southwest Royalties, Inc. as Vice President and Exploitation Manager and by Merit Energy Company in various engineering positions. Mr. Morton began his career in 1983 with Arco Oil and Gas Company as an Operations/Analytical Engineer before moving to a Production Supervisor position. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

CGA. Approximately 55 percent of the proved reserves estimates shown herein at December 31, 2019 have been independently prepared by CGA, a leader of petroleum property analysis for industry and financial institutions. CGA was founded in 1960 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 27, 2020, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 32 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

NSAI. Approximately 45 percent of the proved reserve estimates shown herein at December 31, 2019 have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 23, 2020, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Craig H. Adams. Mr. Adams, a Licensed Professional Engineer in the State of Texas (License No. 68137), has been practicing consulting petroleum engineering at NSAI since 1997 and has over 12 years of prior industry experience. He graduated from Texas Tech University in 1985 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Adams meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Our oil and natural gas reserves. The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2019. Our reserve estimates and our calculation of future net cash flows are based on SEC pricing of (i) $52.19 per Bbl WTI posted oil price and $2.58 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality differentials by property.

	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)
Operating Areas:			
Delaware Basin	339	1,300	556
Midland Basin	280	998	446
Total	619	2,298	1,002

The following table sets forth our estimated proved reserves by category at December 31, 2019:

	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)	Percent of Total
Proved developed producing	432	1,779	728	72%
Proved developed non-producing	10	39	17	2%
Proved undeveloped	177	480	257	26%
Total proved	619	2,298	1,002	100%
Total proved developed	442	1,818	745	74%

Changes to proved reserves. The following table sets forth the changes in our proved reserve volumes by area during the year ended December 31, 2019 (in MMBoe):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
Operating Areas:					
Delaware Basin	(79)	111	6	(102)	(54)
Midland Basin	(42)	66	3	(3)	(91)
Total	(121)	177	9	(105)	(145)

Extensions and discoveries. Extensions and discoveries of approximately 177 MMBoe were primarily the result of our horizontal drilling programs in our operating areas. Proved developed reserves increased approximately 106 MMBoe due to our drilling activity in 2019, and based upon this activity, we added approximately 71 MMBoe of new proved undeveloped reserves.

Purchases and sales of minerals-in-place. Our purchases of minerals-in-place were primarily the result of certain acquisitions and nonmonetary transactions during 2019. Our sales of 105 MMBoe of minerals-in-place were the result of various divestitures and nonmonetary transactions during 2019, primarily the New Mexico Shelf divestiture. See Note 5 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information.

Revisions of previous estimates. Revisions of previous estimates were composed of (i) 28 MMBoe of negative revisions primarily due to the reclassification of proved undeveloped reserves to unproved as they were no longer expected to be developed within five years of the date of their initial recognition, (ii) 82 MMBoe of net negative performance and other revisions and (iii) 35 MMBoe of negative price revisions. Our proved reserves at December 31, 2019 were determined using the SEC prices of $52.19 per Bbl of oil for WTI and $2.58 per MMBtu of natural gas for Henry Hub spot, as compared to corresponding prices of $62.04 per Bbl of oil and $3.10 per MMBtu of natural gas at December 31, 2018. Negative performance revisions were primarily the result of our recent capital programs that included projects testing tighter well spacing. We have modified our development approach to prioritize wider spacing between wells in order to maximize well performance and program economics.

Proved undeveloped reserves. At December 31, 2019, we had approximately 257 MMBoe of proved undeveloped reserves as compared to 363 MMBoe at December 31, 2018.

The following table summarizes the changes in our proved undeveloped reserves during 2019 (in MMBoe):

At December 31, 2018	363
Extensions and discoveries	71
Purchases of minerals-in-place	3
Sales of minerals-in-place	(4)
Revisions of previous estimates	(83)
Conversion to proved developed reserves	(93)
At December 31, 2019	257

Extensions and discoveries. Extensions and discoveries of approximately 71 MMBoe are primarily the result of new proved undeveloped locations that were added as a result of our drilling program during 2019.

Revisions of previous estimates. Negative revisions of previous estimates of approximately 83 MMBoe are primarily attributable to (i) 48 MMBoe of negative revisions primarily due to revisions in our spacing assumptions, (ii) 28 MMBoe of negative revisions for properties that are no longer expected to be developed within five years of the date of their initial recognition and were removed from our current drilling plans, and (iii) 7 MMBoe of other negative revisions including negative price revisions. Negative performance revisions were primarily the results of our recent capital programs that included projects testing tighter well spacing. We have modified our development approach to prioritize wider spacing between wells in order to maximize well performance and program economics.

Conversion to proved developed reserves. The following table sets forth proved undeveloped reserves converted to proved developed reserves and the associated investment required to convert proved undeveloped reserves to proved developed reserves during the year ended December 31, 2019:

Proved Undeveloped Reserves Converted to Proved Developed Reserves			**Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves**
Oil (MMBbl)	**Natural Gas (Bcf)**	**Total (MMBoe)**	**(in millions)**
63	178	93	$ 1,086 (a)

(a) Of this amount, approximately $100 million was spent in 2019 on proved undeveloped reserves that were not converted to proved developed reserves by December 31, 2019.

Historically, our drilling programs were substantially funded from our cash flows from operations and borrowings from our Credit Facility. Based on our current expectations of our cash flows and drilling programs over the next five years, which includes drilling of proved undeveloped and unproved locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and with borrowings from our Credit Facility, if needed. Based on SEC pricing as of December 31, 2019, estimated future development costs required for the development of proved undeveloped reserves are projected to be approximately $2.4 billion over the next five years.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by area at December 31, 2019:

	Developed Acres (a)		Undeveloped Acres (b)		Total Acres	
(in thousands)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Operating Areas:						
Delaware Basin	325	220	199	132	524	352
Midland Basin	213	152	72	45	285	197
Total	538	372	271	177	809	549

(a) Developed acres are acres attributable or assigned to wells producing economic quantities of oil or natural gas and do not include undrilled acreage held by production.

(b) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2019 by operating area:

	2020		2021		2022		Thereafter	
(in thousands)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Operating Areas:								
Delaware Basin	14	4	8	4	5	3	8	8
Midland Basin	—	—	1	1	2	—	—	—
Total	14	4	9	5	7	3	8	8

At December 31, 2019, we had approximately 82,000 gross and 69,000 net acres subject to a continuous development clause or similar drilling commitments. Historically, we have not experienced material expiration of acres due to non-compliance and we do not anticipate any material expirations during 2020 or any future periods.

Drilling Activities

For summary tables that set forth information with respect to wells drilled and completed for the years ended December 31, 2019, 2018 and 2017, see “Item 1. Business—Drilling Activities.”

Our Production, Prices and Expenses

For a summary table that sets forth information concerning our production and operating data from operations for the years ended December 31, 2019, 2018 and 2017, see “Item 1. Business—Our Production, Prices and Expenses.”

Productive Wells

For a summary table that sets forth the number of productive oil and natural gas wells on our properties at December 31, 2019, 2018 and 2017, see “Item 1. Business—Productive Wells.”

Title to Our Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties, and depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens that we believe do not materially interfere with the use or affect our carrying value of the properties.

Item 3. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information

Our common stock trades on the NYSE under the symbol "CXO." As of February 14, 2020, there were 1,467 holders of record of our common stock.

Dividend Policy

For information about dividends, see "Item 8. Financial Statements and Supplementary Data."

Issuer Purchases of Equity Securities

The following table sets forth repurchases of our common stock during the three months ended December 31, 2019:

Period	Total number of shares purchased (a)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (b)	Approximate dollar value of shares that may yet be purchased under the plans or programs (b) (in billions)
October 1, 2019 - October 31, 2019	1,457	$ 64.77	—	$ 1.50
November 1, 2019 - November 30, 2019	2,367,490	$ 74.41	2,367,243	$ 1.30
December 1, 2019 - December 31, 2019	933,904	$ 79.15	933,127	$ 1.25
Total	3,302,851	$ 75.75	3,300,370	$ 1.25

(a) Includes 2,481 shares that were withheld by us to satisfy tax withholding obligations of certain employees that arose upon the lapse of restrictions on share-based awards during the fourth quarter of 2019.

(b) During the fourth quarter of 2019, we repurchased and retired 3,300,370 common shares for $250 million under our $1.5 billion share repurchase program that was publicly announced in September 2019. The program does not have a stated expiration date.

Item 6. Selected Financial Data

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included in this report.

Selected Historical Financial Information

Our results of operations for the periods presented below may not be comparable either from period to period or going forward. We have completed numerous acquisitions, dispositions and nonmonetary transactions that impact the comparability of the selected financial data between periods. In addition, and due in part to the aforementioned factors, the selected financial data between periods was impacted by significant changes in our capital structure, including various debt and equity financing transactions.

Our financial data below is derived from (i) our audited consolidated financial statements included in this report and (ii) other audited consolidated financial statements of ours not included in this report.

	Years Ended December 31,				
(in millions, except per share amounts)	**2019 (a) (b)**	**2018 (a)**	**2017 (a)**	**2016 (b)**	**2015**
Statement of operations data:					
Total operating revenues	$ 4,592	$ 4,151	$ 2,586	$ 1,635	$ 1,804
Total operating costs and expenses	(5,579)	(1,221)	(1,515)	(3,709)	(1,479)
Income (loss) from operations	$ (987)	$ 2,930	$ 1,071	$ (2,074)	$ 325
Net income (loss)	$ (705)	$ 2,286	$ 956	$ (1,462)	$ 66
Earnings per share:					
Basic net income (loss)	$ (3.55)	$ 13.28	$ 6.44	$ (10.85)	$ 0.54
Diluted net income (loss)	$ (3.55)	$ 13.25	$ 6.41	$ (10.85)	$ 0.54
Dividends declared per share	$ 0.50	$ —	$ —	$ —	$ —
Other financial data:					
Net cash provided by operations	$ 2,836	$ 2,558	$ 1,695	$ 1,384	$ 1,530
Net cash used in investing activities	$ (1,993)	$ (2,216)	$ (1,719)	$ (2,225)	$ (2,602)
Net cash provided by (used in) financing activities	$ (773)	$ (342)	$ (29)	$ 665	$ 1,301
Adjusted EBITDAX (non-GAAP) (d)	$ 3,082	$ 2,752	$ 1,893	$ 1,633	$ 1,713

	December 31,				
(in millions)	**2019 (a) (b)**	**2018 (a)**	**2017 (a)**	**2016 (b) (c)**	**2015 (c)**
Balance sheet data:					
Cash and cash equivalents	$ 70	$ —	$ —	$ 53	$ 229
Property and equipment, net	21,327	22,313	13,041	11,302	10,976
Total assets	24,732	26,294	13,732	12,119	12,642
Long-term debt	3,955	4,194	2,691	2,741	3,332
Stockholders' equity	17,782	18,768	8,915	7,623	6,943

(a) See Notes 4 and 5 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a summary of acquisitions, divestitures and nonmonetary transactions included in our financial data for the selected years, and Note 10 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of associated debt financing transactions. In addition, see Note 2 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a summary of certain other asset divestitures.

(b) Impairments of long-lived assets of $890 million and $1.5 billion are included in income (loss) from operations for the years ended December 31, 2019 and December 31, 2016, respectively. In addition, a goodwill impairment charge of $282 million is included in income (loss) from operations for the year ended December 31, 2019.

(c) During 2016 and 2015, we issued approximately 10.4 million and 15.8 million shares of our common stock, respectively, in public offerings and received net proceeds of approximately $1.3 billion and $1.5 billion, respectively.

(d) Refer to "Item 1. Business—Non-GAAP Financial Measures and Reconciliations" for a definition and reconciliation of adjusted EBITDAX.

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this report.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from those implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements" and "Item 1A. Risk Factors" for further details about these statements.

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. We are one of the largest operators in the Permian Basin of West Texas and Southeast New Mexico. Concho's legacy in the Permian Basin provides us a deep understanding of operating and geological trends, and we are actively developing our resource base utilizing large-scale development projects, which include long-lateral wells and multi-well pad locations, throughout our operating areas. Oil comprised 62 percent of our 1,002 MMBoe of estimated proved reserves at December 31, 2019 and 63 percent of our 121 MMBoe of production for 2019. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 93 percent of our proved developed producing reserves and 75 percent of our 5,981 gross wells at December 31, 2019. By controlling operations, we are able to more effectively manage the development strategy as well as the cost and timing of exploration and development of our properties.

Financial and Operating Performance

Our financial and operating performance for 2019 included the following highlights:

- Net loss was $705 million ($(3.55) per diluted share) as compared to net income of $2,286 million ($13.25 per diluted share) in 2018. The decrease was primarily due to:
    - $1,727 million change in (gain) loss on derivatives due to a loss on derivatives of $895 million during 2019, as compared to a gain of $832 million during 2018;
    - $890 million of impairments of long-lived assets during 2019;
    - $282 million of impairments of goodwill during 2019;
    - $630 million decrease in gain on disposition of assets due to a $170 million net gain during 2019 primarily due to the contribution of certain infrastructure assets in exchange for a cash distribution and an equity ownership interest in the entity in July 2019, partially offset by net losses from certain nonmonetary transactions, as compared to a net gain of $800 million primarily related to certain acquisitions and divestitures during 2018, as discussed in Note 5 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data”; and
    - $486 million increase in depreciation, depletion and amortization expense, primarily due to the increase in production and the increase in the depletion rate per Boe.

  partially offset by:
    - $441 million increase in oil and natural gas revenues as a result of a 26 percent increase in production, partially offset by a 12 percent decrease in commodity price realizations per Boe (excluding the effects of derivative activities);
    - $205 million increase in other income, primarily due to the gain of $289 million on the sale of our ownership interest in the subsidiary of our equity method investment, Oryx Southern Delaware Holdings, LLC (“Oryx”); and
    - $757 million change in income taxes due to a $154 million tax benefit during 2019, as compared to a $603 million tax expense during 2018.
- Average daily sales volumes increased by 26 percent from 262,937 Boe per day during 2018 to 331,086 Boe per day during 2019.
- Net cash provided by operating activities increased by $278 million to $2,836 million in 2019, as compared to $2,558 million in 2018, primarily due to an increase in oil and natural gas revenues and changes related to cash settlements on derivatives, partially offset by an increase in operating costs on our oil and natural gas properties.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. See “Item 1A. Risk Factors” for a description of the factors that may impact future commodity prices, including the price of oil, natural gas and natural gas liquids.

Although we cannot predict the occurrence of events that may affect future commodity prices, or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Notes 9 and 19 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our commodity derivative positions at December 31, 2019 and additional derivative contracts entered into subsequent to December 31, 2019, respectively.

The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2019, 2018 and 2017, as well as the high and low NYMEX prices for the same periods:

	Years Ended December 31,		
	2019	2018	2017
Average NYMEX prices:			
Oil (Bbl)	$ 57.03	$ 64.81	$ 50.97
Natural gas (MMBtu)	$ 2.53	$ 3.07	$ 3.02
High and Low NYMEX prices:			
Oil (Bbl):			
High	$ 66.30	$ 76.41	$ 60.42
Low	$ 45.41	$ 42.53	$ 42.53
Natural gas (MMBtu):			
High	$ 3.59	$ 4.84	$ 3.72
Low	$ 2.07	$ 2.55	$ 2.56

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $63.27 and $49.57 per Bbl and $2.20 and $1.77 per MMBtu, respectively, during the period from January 1, 2020 to February 14, 2020. At February 14, 2020, the NYMEX oil price and NYMEX natural gas price were $52.05 per Bbl and $1.84 per MMBtu, respectively.

Historically, and during the year ended December 31, 2019, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $20.19 per Bbl, $29.94 per Bbl and $25.06 per Bbl during the years ended December 31, 2019, 2018 and 2017, respectively.

Potential cost inflation. Oilfield service and supply costs are also subject to supply and demand dynamics. As companies expand their drilling and development activities, the demand for third-party oilfield services and suppliers may also increase. As such, when commodity prices begin to trend upward, we expect demand for oilfield services and supplies to grow, and the costs of drilling, equipping and operating our wells and infrastructure could increase.

Recent Events

The following are significant recent developments since our last quarterly report on Form 10-Q was filed on October 30, 2019:

2020 capital budget. In February 2020, our board of directors approved our 2020 capital budget of up to $2.9 billion. We expect to spend between $2.6 billion and $2.8 billion on drilling and completion activity.

Dividends. On February 18, 2020, our board of directors approved a cash dividend of $0.20 per share for the first quarter of 2020 that is expected to be paid on March 27, 2020 to stockholders of record as of February 28, 2020. The total cash dividend paid to our stockholders during 2019 was $100 million.

New Mexico Shelf divestiture. In November 2019, we closed on our New Mexico Shelf asset divestiture and received cash proceeds of $837 million, subject to post-closing adjustments. Refer to Note 5 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding the New Mexico Shelf divestiture. We used the proceeds from this divestiture to repay outstanding borrowings under our Credit Facility and initiate the share repurchase program, as discussed below.

Share repurchase program. In September 2019, we announced that our board of directors authorized the initiation of a share repurchase program for up to $1.5 billion of our common stock. A portion of the proceeds from the New Mexico Shelf divestiture was used to initiate the share repurchase program. As of December 31, 2019, we had repurchased and retired 3,300,370 shares under the program at an aggregate cost of $250 million.

Derivative Financial Instruments

Derivative financial instrument exposure. At December 31, 2019, the fair value of our financial derivatives was a net liability of $102 million. Under the terms of our financial derivative instruments, we do not have exposure to potential “margin calls” on our financial derivative instruments. The terms of our Credit Facility do not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party.

New commodity derivative contracts. After December 31, 2019, we entered into derivative contracts to hedge additional amounts of estimated future production. Refer to Note 19 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding these commodity derivative contracts.

Results of Operations

The following table sets forth summary production and operating data for the years ended December 31, 2019, 2018 and 2017. The actual historical data in this table excludes results from the RSP Acquisition for periods prior to July 19, 2018. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions and divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2019	2018	2017
Production and operating data:			
Net production volumes:			
Oil (MBbl)	76,369	61,251	43,472
Natural gas (MMcf)	266,865	208,326	161,089
Total (MBoe)	120,847	95,972	70,320
Average daily production volumes:			
Oil (Bbl)	209,230	167,811	119,101
Natural gas (Mcf)	731,137	570,756	441,340
Total (Boe)	331,086	262,937	192,658
Average prices per unit: (a)			
Oil, without derivatives (Bbl)	$ 54.03	$ 56.22	$ 48.13
Oil, with derivatives (Bbl) (b)	$ 52.35	$ 52.73	$ 49.93
Natural gas, without derivatives (Mcf)	$ 1.74	$ 3.40	$ 3.07
Natural gas, with derivatives (Mcf) (b)	$ 1.86	$ 3.37	$ 3.06
Total, without derivatives (Boe)	$ 38.00	$ 43.25	$ 36.78
Total, with derivatives (Boe) (b)	$ 37.19	$ 40.98	$ 37.88
Operating costs and expenses per Boe: (a)			
Oil and natural gas production	$ 5.93	$ 6.14	$ 5.80
Production and ad valorem taxes	$ 2.89	$ 3.19	$ 2.82
Gathering, processing and transportation	$ 0.96	$ 0.58	$ —
Depreciation, depletion and amortization	$ 16.25	$ 15.41	$ 16.29
General and administrative	$ 2.69	$ 3.25	$ 3.46

(a) Per unit and per Boe amounts calculated using dollars and volumes rounded to thousands.

(b) Includes the effect of net cash receipts from (payments on) derivatives:

	Years Ended December 31,		
(in millions)	2019	2018	2017
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ (129)	$ (213)	$ 79
Natural gas derivatives	31	(5)	—
Total	$ (98)	$ (218)	$ 79

The presentation of average prices with derivatives is a result of including the net cash receipts from (payments on) commodity derivatives that are presented in our consolidated statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

The following table presents selected production data for the fields that represent greater than 15 percent of our total proved reserves at December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
	2019	2018	2017
Production:			
Delaware Basin:			
Oil (MMBbl)	44	34	25
Natural gas (Bcf)	170	130	103
Total (MMBoe)	72	56	42
Midland Basin:			
Oil (MMBbl)	29	21	11
Natural gas (Bcf)	76	52	30
Total (MMBoe)	42	30	16
Yeso:			
Oil (MMBbl)	(a)	(a)	7
Natural gas (Bcf)	(a)	(a)	28
Total (MMBoe)	(a)	(a)	12

(a) Represents less than 15% of our total proved reserves for the year indicated.

The following tables and related discussion set forth key operating and financial data as of and for the years ended December 31, 2019 and 2018. For similar operating and financial data and discussion of our 2018 results compared to our 2017 results, refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" under Part II of our annual report on Form 10-K for the year ended December 31, 2018, which was filed with the SEC on February 20, 2019.

Oil and natural gas revenues. Revenue from oil and natural gas operations was $4,592 million for the year ended December 31, 2019, an increase of $441 million (11 percent) from $4,151 million for 2018. The increase was primarily due to the increase in oil and natural gas production, in part due to the RSP Acquisition, partially offset by the decrease in realized oil and natural gas prices (excluding the effects of derivative activities).

Specific factors affecting oil and natural gas revenues for the years ended December 31, 2019 and 2018 include the following:

	Years Ended December 31,	
	2019	**2018**
Net production volumes:		
Oil (MBbl)	76,369	61,251
Natural gas (MMcf)	266,865	208,326
Average prices per unit:		
Average NYMEX oil price (Bbl)	$ 57.03	$ 64.81
Realized oil price (Bbl)	$ 54.03	$ 56.22
Differential to NYMEX	$ (3.00)	$ (8.59)
Average NYMEX natural gas price (MMBtu)	$ 2.53	$ 3.07
Realized natural gas price (Mcf)	$ 1.74	$ 3.40
Average realized natural gas price as a percentage of NYMEX	69%	111%

- total oil production increased 15,118 MBbl (25 percent) for the year ended December 31, 2019 as compared to 2018;
- average realized oil price (excluding the effects of derivative activities) decreased 4 percent for the year ended December 31, 2019 as compared to 2018. The decrease in average realized oil price was primarily due to a decrease in the average NYMEX price, partially offset by the narrowing of the basis differential. The basis differential (referred to as the "Mid-Cush differential") between the location of Midland, Texas and Cushing, Oklahoma (settlement location for NYMEX pricing) for our oil directly impacts our realized oil price. For the years ended December 31, 2019 and 2018, the average market Mid-Cush differentials were price reductions of $1.49 per Bbl and $6.51 per Bbl, respectively;
- total natural gas production increased 58,539 MMcf (28 percent) for the year ended December 31, 2019 as compared to 2018; and
- average realized natural gas price (excluding the effects of derivative activities) decreased 49 percent for the year ended December 31, 2019 as compared to 2018. We derive a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids decreased from $29.94 per Bbl during the year ended December 31, 2018 to $20.19 per Bbl during the year ended December 31, 2019. In addition, during the latter part of 2018 and into 2019, amid concerns of rising natural gas production relative to the ability to transport natural gas out of the Permian Basin, the price differential for natural gas residue increased significantly. These widening natural gas residue differentials negatively impacted our realized natural gas prices during the year ended December 31, 2019. The combination of these factors resulted in a realized natural gas price of 69 percent of the average NYMEX natural gas price for the year ended December 31, 2019. Because of our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues and the Permian Basin local markets for residue gas settling more in parity with NYMEX price, our realized natural gas price (excluding the effects of derivatives) for the year ended December 31, 2018 reflected a price greater than the related NYMEX natural gas price.

Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the years ended December 31, 2019 and 2018:

	Years Ended December 31,			
	2019		2018	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 681	$ 5.64	$ 553	$ 5.76
Workover costs	35	0.29	37	0.38
Total oil and natural gas production expenses	$ 716	$ 5.93	$ 590	$ 6.14

Lease operating expenses were $681 million ($5.64 per Boe) for the year ended December 31, 2019, an increase of $128 million (23 percent) from $553 million ($5.76 per Boe) for 2018. The increase in lease operating expenses during 2019 as compared to the prior year was primarily the result of an increase in well count due to our acquisitions during 2018, and additional wells successfully drilled and completed during 2018 and 2019, partially offset by the New Mexico Shelf divestiture. The decrease in lease operating expenses per Boe was primarily due to higher production from our drilling program during 2019 and the New Mexico Shelf divestiture.

Workover costs were $35 million ($0.29 per Boe) for the year ended December 31, 2019, a decrease of $2 million from $37 million ($0.38 per Boe) for 2018. The decrease in workover costs per Boe during 2019 was primarily due to increased production and decreased workover activity.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the years ended December 31, 2019 and 2018:

	Years Ended December 31,			
	2019		2018	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Production taxes	$ 282	$ 2.33	$ 272	$ 2.84
Ad valorem taxes	67	0.56	33	0.35
Total production and ad valorem taxes	$ 349	$ 2.89	$ 305	$ 3.19

Production taxes per unit of production were $2.33 per Boe during the year ended December 31, 2019, a decrease of 18 percent from $2.84 per Boe during 2018. Over the same period, our revenue per Boe (excluding the effects of derivatives) decreased 12 percent. The decrease in production taxes per unit of production was due to lower realized revenue per Boe along with a higher percentage of our total production originating in Texas, which has a lower tax rate than New Mexico.

Production taxes fluctuate with the market value of our production sold, while ad valorem taxes are generally based on the valuation of our oil and natural gas properties at the beginning of the year, which vary across the different areas in which we operate.

Ad valorem taxes increased $34 million during the year ended December 31, 2019 as compared to the year ended December 31, 2018, primarily due to additional wells drilled and completed, new wells acquired and an increase in tax rates in certain counties. The increase in ad valorem taxes per Boe during the year ended December 31, 2019 as compared to the year ended December 31, 2018 was primarily due to an increase in tax rates.

Gathering, processing and transportation costs. The following table shows the gathering, processing and transportation costs for the years ended December 31, 2019 and 2018:

	Years Ended December 31,			
	2019		2018	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Gathering, processing and transportation costs	$ 115	$ 0.96	$ 55	$ 0.58

Gathering, processing and transportation costs were $115 million ($0.96 per Boe) for the year ended December 31, 2019, an increase of 109 percent from $55 million for 2018. The increase in gathering, processing and transportation costs for 2019 was primarily due to a certain crude oil gathering and transportation contract that, among other things, was modified to allow repurchase rights. As such, costs related to this contract that were previously recorded as a deduction to revenue during 2018 are now recorded in gathering, processing and transportation costs. In addition, contributing to the increase in gathering, processing and transportation costs was the RSP Acquisition and the increase in production. The increase in gathering, processing and transportation costs per Boe was primarily related to the aforementioned crude oil gathering and transportation contract and fixed costs associated with certain contracts. Additionally, we entered into a marketing contract that requires us to deliver 50,000 barrels of oil per day that began in October 2019. As a result of this contract, we expect our realized oil prices, as well as our gathering, processing and transportation costs, to increase for the related oil production in future periods.

Exploration and abandonments expense. The following table provides the components of our exploration and abandonments expense for the years ended December 31, 2019 and 2018:

	Years Ended December 31,	
(in millions)	**2019**	**2018**
Geological and geophysical	$ 17	$ 12
Leasehold abandonments	147	35
Other	37	18
Total exploration and abandonments	$ 201	$ 65

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis.

We recorded $147 million and $35 million of leasehold abandonments for the years ended December 31, 2019 and 2018, respectively, primarily related to certain expiring acreage where we had no plans to extend the lease and acreage where we had no long-term plans to drill.

Our other expense for the periods presented above primarily consists of surface and title costs on locations we no longer intend to drill, certain plugging costs and delay rentals. The increase in other expense during 2019 was primarily due to the abandonments of certain exploratory wells, in part due to mechanical issues encountered during the completion of certain wells that made them unable to produce hydrocarbons in economic quantities.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2019 and 2018:

	Years Ended December 31,			
	2019		2018	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 1,932	$ 15.98	$ 1,453	$ 15.14
Depreciation of other property and equipment	30	0.25	22	0.23
Amortization of intangible assets	2	0.02	3	0.04
Total depletion, depreciation and amortization	$ 1,964	$ 16.25	$ 1,478	$ 15.41
Oil price used to estimate proved oil reserves at period end	$ 52.19		$ 62.04	
Natural gas price used to estimate proved natural gas reserves at period end	$ 2.58		$ 3.10	

Depletion of proved oil and natural gas properties was $1,932 million ($15.98 per Boe) for the year ended December 31, 2019, an increase of $479 million (33 percent) from $1,453 million ($15.14 per Boe) for 2018. The increase in depletion expense was due to an increase in production and the depletion rate per Boe. The increase in depletion expense per Boe was primarily due to the RSP Acquisition and certain downward adjustments to our proved oil and natural gas reserves, partially offset by lower depletion of the Yeso field due to the impairment charge recognized during 2019, as discussed below, and the New Mexico Shelf divestiture.

Impairments of long-lived assets. During the year ended December 31, 2019, we recognized impairments of long-lived assets of $890 million. During the second quarter of 2019, we recognized an impairment charge of $868 million that was primarily attributable to certain downward adjustments to our economically recoverable proved oil and natural gas reserves associated with properties in our Yeso field due to the decline in commodity prices. During the third quarter of 2019, we recognized an additional impairment charge of $20 million primarily to reduce the carrying value of the remaining assets in the Yeso field to their fair value. Our Yeso field was primarily composed of the New Mexico Shelf assets that we sold in November 2019. We did not recognize an impairment during 2018. See Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information on the fair value assumptions used for long-lived assets.

It is reasonably possible that the estimate of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to further impair carrying values. The primary factors that may affect estimates of future net cash flows are (i) commodity prices including differentials, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) changes in income and expenses from integrated assets.

Impairments of goodwill. During the year ended December 31, 2019, we recognized goodwill impairments of $282 million. The impairments were due to a decline in our market capitalization along with declines in observed control premiums during the second half of 2019 and the New Mexico Shelf divestiture. See Note 2 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information on the impairment of our goodwill.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2019 and 2018:

	Years Ended December 31,			
	2019		2018	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 259	$ 2.13	$ 248	$ 2.58
Less: Operating fee reimbursements	(18)	(0.15)	(19)	(0.19)
Non-cash stock-based compensation	85	0.71	82	0.86
Total general and administrative expenses	$ 326	$ 2.69	$ 311	$ 3.25

Total general and administrative expenses were $326 million ($2.69 per Boe) for the year ended December 31, 2019, an increase of $15 million (5 percent) from $311 million ($3.25 per Boe) for 2018. The increase in total general and administrative expenses was primarily due to an increase in the average employee headcount, in part due to the RSP Acquisition, partially offset by lower variable compensation accruals during 2019. The decrease in total general and administrative expenses per Boe was primarily the result of increased production, partially offset by the increase in total general and administrative expenses.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions to general and administrative expenses in the consolidated statements of operations. We earned reimbursements of approximately $18 million and $19 million during the years ended December 31, 2019 and 2018, respectively.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the years ended December 31, 2019 and 2018:

	Years Ended December 31,	
(in millions)	**2019**	**2018**
Gain (loss) on derivatives:		
Oil derivatives	$ (1,003)	$ 848
Natural gas derivatives	108	(16)
Total	$ (895)	$ 832

The following table represents our net cash receipts from (payments on) derivatives for the years ended December 31, 2019 and 2018:

	Years Ended December 31,	
(in millions)	**2019**	**2018**
Net cash receipts from (payments on) derivatives:		
Oil derivatives	$ (129)	$ (213)
Natural gas derivatives	31	(5)
Total	$ (98)	$ (218)

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains; while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain on disposition of assets, net. During the year ended December 31, 2019, we recorded a net gain on disposition of assets of $170 million, primarily due to a gain of $297 million related to our contribution of certain water infrastructure assets in exchange for a cash distribution and an equity ownership interest in an entity, partially offset by losses related to certain nonmonetary transactions and the New Mexico Shelf divestiture.

During the year ended December 31, 2018, we recognized a net gain on disposition of assets of $800 million, which was primarily due to (i) a gain of $575 million related to our February 2018 acquisition and divestiture primarily in the Midland Basin, (ii) a gain of $134 million related to our Delaware Basin divestiture in January 2018 and (iii) a gain of $79 million related to the contribution of certain infrastructure assets in the southern portion of the Delaware Basin. In addition, during 2018, we completed multiple nonmonetary transactions that included the exchange of both proved and unproved oil and natural gas properties that resulted in pre-tax gains of $15 million.

Refer to Notes 2 and 5 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for further discussion of certain of the 2019 and 2018 transactions mentioned above.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2019 and 2018:

	Years Ended December 31,	
(in millions)	**2019**	**2018**
Interest expense, as reported	$ 185	$ 149
Capitalized interest	19	8
Interest expense, excluding impact of capitalized interest	$ 204	$ 157
Weighted average interest rate – Credit Facility	4.2%	4.5%
Weighted average interest rate – senior notes	4.4%	4.3%
Total weighted average interest rate	4.4%	4.3%
Weighted average Credit Facility balance	$ 439	$ 172
Weighted average senior notes balance	4,000	3,195
Total weighted average debt balance	$ 4,439	$ 3,367

The increase in interest expense during the year ended December 31, 2019 as compared to 2018 was primarily due to the increase in the weighted average debt balance, partially offset by the increase in capitalized interest and lower weighted average interest rate on our Credit Facility. The increase in the weighted average senior notes balance was primarily due to the senior notes issued in connection with the RSP Acquisition.

Other income, net. During the year ended December 31, 2019, we recorded other income of $313 million, primarily related to $289 million of cash proceeds from the sale of our ownership interest in Oryx I, a crude oil gathering and transportation system in the Delaware Basin (“Oryx I”). See Note 2 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding this sale.

During the year ended December 31, 2018, we recorded other income of $108 million primarily related to a cash distribution received from Oryx. See Note 2 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding this distribution.

Income tax provisions. We recorded an income tax benefit of $154 million and an income tax expense of $603 million for the years ended December 31, 2019 and 2018, respectively. The change to income tax benefit in 2019 from income tax expense in 2018 was primarily due to the pre-tax loss during 2019 as compared to pre-tax income during 2018.

For the year ended December 31, 2019, we recorded an income tax benefit of $21 million due to the decrease in our applicable state tax rate in New Mexico as a result of the New Mexico Shelf divestiture. During the second quarter of 2019, the state of New Mexico enacted a tax law which, among other changes, amended the apportioned net operating loss carryforwards for corporations. As a result of this law change, we recorded a deferred state tax benefit of $6 million for the year ended December 31, 2019.

For the year ended December 31, 2018, the Company completed its accounting for all of the enactment-date tax effects of the TCJA and recognized an adjustment to the provisional amount recorded as of the enactment date of approximately $7 million primarily related to the deductibility of certain performance-based compensation expenses.

Our effective income tax rates were 18 percent and 21 percent for the years ended December 31, 2019 and 2018, respectively. Our effective income tax rate of 18 percent for the year ended December 31, 2019 differed from the federal statutory tax rate of 21 percent primarily due to (i) nondeductible goodwill impairment; (ii) deferred benefit recognized from the decrease in the applicable state tax rate as a result of the New Mexico Shelf divestiture; (iii) state income taxes, including the impact of the enacted New Mexico tax law change; and (iv) research and development credits, net of unrecognized tax benefits.

Our effective tax rate of 21 percent for the year ended December 31, 2018 approximated the federal statutory tax rate of 21 percent primarily due to the benefits from (i) research and development credits, net of unrecognized tax benefits; (ii) the change in the applicable state tax rates due to the RSP Acquisition; and (iii) the adjustment to provisional TCJA tax effects; offset by (iv) other recurring permanent differences and state income taxes that affect our rates.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are for (i) development, exploration and acquisition of oil and natural gas assets, (ii) midstream joint ventures and other capital commitments, (iii) payment of contractual obligations and (iv) working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our Credit Facility, proceeds from the disposition of assets or alternative financing sources, as discussed in "— Capital resources" below.

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions, during the years ended December 31, 2019 and 2018 totaled $3.0 billion and $2.6 billion, respectively. The primary reason for the differences in costs incurred and cash flow expenditures included in our consolidated statements of cash flows was the timing of payments. Our 2019 capital expenditures were primarily funded from cash flows from operations and borrowings under our Credit Facility.

2020 capital budget. In February 2020, our board of directors approved our 2020 capital budget of up to $2.9 billion. We expect to spend between $2.6 billion and $2.8 billion on drilling and completion activity.

Dividends. On February 18, 2020, our board of directors declared a cash dividend of $0.20 per share for the first quarter of 2020 that is expected to be paid on March 27, 2020 to stockholders of record as of February 28, 2020. Total cash dividends paid to our stockholders during the year ended December 31, 2019 were $100 million. We intend to continue to pay a quarterly dividend of $0.20 in the future, however, any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant.

Share repurchase program. In September 2019, we announced that our board of directors authorized the initiation of a share repurchase program for up to $1.5 billion of our common stock. The maximum aggregate dollar amount of repurchases that may be made in any quarter requires advance approval of the board of directors. The share repurchase program may be modified, suspended or terminated at any time by our board of directors and we are not obligated to acquire any specific number of shares.

We used a portion of the proceeds from the New Mexico Shelf divestiture, which closed in November 2019, to initiate share repurchases in the fourth quarter of 2019, while maintaining sufficient liquidity to fund our capital commitments and dividend payments. All additional future repurchases will require the approval of the Company's board of directors. As of December 31, 2019, we repurchased and retired 3,300,370 shares under the program at an aggregate cost of $250 million.

Other than the customary purchase of leasehold acreage, our capital budgets are exclusive of acquisitions. We do not have a specific acquisition budget because the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise.

Acquisitions. The following table reflects our expenditures for acquisitions of proved and unproved properties for the years ended December 31, 2019 and 2018:

	Years Ended December 31,	
(in millions)	**2019**	**2018**
Property acquisition costs:		
Proved	$ 8	$ 4,136
Unproved	50	3,617
Total property acquisition costs (a)	$ 58	$ 7,753

(a) Included in the property acquisition costs above are budgeted unproved leasehold acreage acquisitions of $50 million and $51 million for the years ended December 31, 2019 and 2018, respectively. Our unbudgeted acquisitions during 2018 were primarily comprised of approximately $7.6 billion of property acquisition costs related to the RSP Acquisition.

Contractual obligations. We had the following contractual obligations at December 31, 2019:

	Payments Due by Period				
(in millions)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Long-term debt (a)	$ 4,000	$ —	$ —	$ —	$ 4,000
Cash interest expense on debt (b)	2,769	235	350	350	1,834
Derivative liabilities (c)	119	112	7	—	—
Asset retirement obligations (d)	139	9	11	5	114
Employment agreements with officers (e)	10	10	—	—	—
Purchase obligations (f)	333	51	109	70	103
Lease obligations (g)	43	21	19	1	2
Total contractual obligations (h)	$ 7,413	$ 438	$ 496	$ 426	$ 6,053

(a) See Note 10 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding future interest payment obligations on our long-term debt. The amounts included in the table above represent principal maturities only.

(b) Cash interest expense on our senior notes is estimated assuming no principal repayment until their maturity dates. Also included in the “Less than 1 year” column is accrued interest at December 31, 2019 of approximately $60 million. At December 31, 2019, we had no variable-rate debt outstanding under our Credit Facility.

(c) Derivative obligations represent commodity derivatives that were valued at December 31, 2019. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market risk. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” and Note 9 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our derivative obligations.

(d) Amounts represent costs related to expected oil and natural gas property abandonments, net of any future accretion.

(e) Represents amounts of cash compensation we are obligated to pay to our officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

(f) Relates to purchase agreements we have entered into including water commitment agreements, throughput volume delivery commitments, fixed and variable power commitments, sand commitment agreements and other commitments.

(g) Relates to our operating and financing leases, including office space, office equipment, drilling rigs, field equipment and vehicles. See Note 11 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding our lease obligations. Included in the “Less than 1 year” column are the Company’s drilling rigs. Drilling rigs are short-term leases and are not capitalized under the lease standard. A portion of these costs will be reimbursed to the Company by other working interest owners.

(h) The amounts above do not include the liability for unrecognized tax benefits. See Note 12 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information.

Off-balance sheet arrangements. Currently, we do not have any material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from (i) operating activities, (ii) borrowings under our Credit Facility, (iii) asset dispositions and (iv) proceeds from bond and equity offerings. In February 2020, our board of directors approved our 2020 capital budget of up to $2.9 billion. We expect to spend between $2.6 billion and $2.8 billion on drilling and completion activity. We expect to fund our 2020 capital budget primarily with operating cash flows. We believe that our current cash and cash equivalents, together with cash flows generated from operating activities and available borrowings under our Credit Facility, will be sufficient to meet our anticipated cash requirements for at least the next 12 months.

The following table summarizes our changes in cash and cash equivalents for the years ended December 31, 2019 and 2018. The discussion of changes in cash and cash equivalents for the year ended December 31, 2017 is included in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under Part II of our Annual Report on Form 10-K for the year ended December 31, 2018, which was filed with the SEC on February 20, 2019.

	Years Ended December 31,	
(in millions)	**2019**	**2018**
Net cash provided by operating activities	$ 2,836	$ 2,558
Net cash used in investing activities	(1,993)	(2,216)
Net cash used in financing activities	(773)	(342)
Net change in cash and cash equivalents	$ 70	$ —

Cash flow from operating activities. The increase in operating cash flows during the year ended December 31, 2019 as compared to 2018 was primarily due to an increase in our total operating revenues of $441 million and an increase of $120 million due to $98 million of settlements paid on derivatives during the year ended December 31, 2019, as compared to $218 million during 2018. The increase was partially offset by an increase in operating expenses on our oil and natural gas properties.

Our net cash provided by operating activities included a reduction of $40 million and a benefit of $4 million for the years ended December 31, 2019 and 2018, respectively, associated with changes in working capital items. Changes in working capital items adjust for the timing of receipts and payments of actual cash.

Cash flow from investing activities. Our investing activities consist primarily of drilling and completion activity, acquisitions and divestitures. The primary reason for the differences in costs incurred on oil and natural gas properties, including acquisitions, and cash flow expenditures is the timing of payments and the issuances of shares of common stock to fund certain acquisitions.

For the year ended December 31, 2019, our net cash used in investing activities was approximately $2.0 billion, which consisted primarily of our investment of approximately $3.1 billion for additions to oil and natural gas properties. This was partially offset by approximately $1.3 billion of cash proceeds from asset dispositions primarily due to the New Mexico Shelf divestiture, the sale of Oryx I and the contribution of certain water infrastructure assets to an entity. We used the proceeds from these and other divestitures to repay our outstanding balance under our Credit Facility. Our capital expenditures during the year ended December 31, 2019 were funded with cash flows from operations and borrowings under our Credit Facility.

For the year ended December 31, 2018, our net cash used in investing activities was approximately $2.2 billion, which consisted primarily of our investment of approximately $2.5 billion for additions to oil and natural gas properties and $136 million of oil and natural gas property acquisitions, partially offset by (i) $361 million of proceeds received from the disposition of certain assets and (ii) a $148 million distribution received from Oryx, one of our equity method investments. The total distribution from Oryx was $157 million, of which $9 million represented cumulative Oryx earnings and was classified as cash flow from operating activities, while the remaining amount of $148 million was classified as cash flow from investing activities. The 2018 expenditures were primarily funded with cash flows from operations.

Cash flow from financing activities. For the year ended December 31, 2019, our net cash used in financing activities was $773 million primarily due to $250 million of common stock repurchases under our share repurchase program, $242 million of net payments under our Credit Facility and $100 million of dividends paid on our common stock. During the year ended December 31, 2019, we decreased our book overdrafts by $159 million.

For the year ended December 31, 2018, our net cash used in financing activities was $342 million. In July 2018, we issued $1.6 billion in aggregate principal amount of senior unsecured notes and used the net proceeds to redeem and cancel certain senior unsecured notes assumed in the RSP Acquisition ("RSP Notes"). We made aggregate payments of approximately $1.2 billion to redeem and cancel the RSP Notes, including make-whole call premiums of $68 million. We also paid accrued interest of $14 million on the RSP Notes. The remaining proceeds, along with borrowings under our Credit Facility, were used to repay the $540 million of outstanding principal under RSP's revolving credit facility, including $1 million in accrued interest. We also made net payments of $80 million on our Credit Facility during 2018.

In September 2017, we elected to enter into an Investment Grade Period under our Credit Facility, which had the effect of releasing all collateral formerly securing our Credit Facility. If the Investment Grade Period under our Credit Facility terminates (whether automatically or by our election), our Credit Facility will once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries. At December 31, 2019, we had unused commitments under our Credit Facility of $2.0 billion.

Advances on our Credit Facility bear interest, at our option, based on:

(i) an alternative base rate, which is equal to the highest of

(a) the prime rate of JPMorgan Chase Bank (4.8 percent at December 31, 2019),

(b) the federal funds effective rate plus 0.5 percent, and

(c) the LIBOR plus 1.0 percent; or

(ii) LIBOR.

Our Credit Facility's interest rates and commitment fees on the unused portion of the available commitment vary depending on our credit ratings from Moody's and S&P. At our current credit ratings, LIBOR Rate Loans and Alternate Base Rate Loans bear interest margins of 150 basis points and 50 basis points per annum, respectively, and commitment fees on the unused portion of the available commitment are 25 basis points per annum.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Historically, we have demonstrated our use of the capital markets by issuing common stock and senior unsecured debt. There are no assurances that we can access the capital markets to obtain additional funding, if needed, and at cost and terms that are favorable to us. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in energy companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time. Utilization of some of these financing sources may require approval from the lenders under our Credit Facility.

Liquidity. Our principal source of liquidity is the available borrowing capacity under our Credit Facility. At December 31, 2019, our commitments from our bank group totaled $2.0 billion, all of which was unused.

Debt ratings. We receive debt credit ratings from S&P, Moody's and Fitch and are designated as investment grade with all three agencies. In determining our ratings, the agencies perform regular reviews and consider a number of qualitative and quantitative factors including, but not limited to, the industry in which we operate, production growth opportunities, liquidity, debt levels and asset and reserve mix.

A downgrade in our credit ratings could (i) negatively impact our costs of capital and our ability to effectively execute aspects of our strategy, (ii) affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt and (iii) negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing. Further, if we are unable to maintain credit ratings of "Ba2" or better from Moody's and "BB" or better from S&P, the Investment Grade Period under our Credit Facility will automatically terminate and cause our Credit Facility to once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

As of the filing date of this Annual Report on Form 10-K, there have been no changes to our credit ratings; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Book capitalization and current ratio. Our net book capitalization at December 31, 2019 was $21.8 billion, consisting of cash and cash equivalents of $70 million, debt of $4.0 billion and stockholders' equity of $17.8 billion. Our net book capitalization at December 31, 2018 was $23.0 billion, consisting of debt of $4.2 billion and stockholders' equity of $18.8 billion. Our ratio of net debt to net book capitalization was 18 percent and 18 percent at December 31, 2019 and 2018, respectively. Our ratio of current assets to current liabilities was 0.89 to 1.0 at December 31, 2019 as compared to 1.04 to 1.0 at December 31, 2018.

Inflation and changes in prices. Our revenues, the value of our assets and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that we are unable to control or predict. During the year ended December 31, 2019, we received an average of $54.03 per barrel of oil and $1.74 per Mcf of natural gas before consideration of commodity derivative contracts compared to $56.22 and $48.13 per barrel of oil and $3.40 and $3.07 per Mcf of natural gas in the years ended December 31, 2018 and 2017, respectively. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business.

Critical Accounting Policies, Practices and Estimates

Our historical consolidated financial statements and related notes to consolidated financial statements contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management's opinion, the more significant reporting areas impacted by management's judgments and estimates are the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairments of long-lived assets, valuation of stock-based compensation, valuation of business combinations, accounting and valuation of nonmonetary transactions, impairments of goodwill, litigation and environmental contingencies, valuation of financial derivative instruments, uncertain tax positions and income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are capitalized. Exploratory drilling costs are initially capitalized, but are charged to expense if and when a well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing fields are sold. This accounting method may yield significantly different results than the full cost method of accounting.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively impair our leasehold positions.

Depletion of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on total estimated proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of two to 39 years.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

This report presents estimates of our proved reserves as of December 31, 2019, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2019 was based on the 12-month unweighted average of the first-day-of-the-month WTI posted price of $52.19 per Bbl for oil and Henry Hub spot natural gas price of $2.58 per MMBtu for natural gas.

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

It should not be assumed that the Standardized Measure included in this report as of December 31, 2019 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2019 Standardized Measure on the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See "Item 1A. Risk Factors" and "Item 2. Properties" for additional information regarding estimates of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

Asset Retirement Obligations

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets. When the judgments used to estimate the initial fair value of the asset retirement obligation change, an adjustment is recorded to both the obligation and the carrying amount of the related long-lived asset. Historically, there have been no significant revisions to our initial estimates once future results became known. See Note 6 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our asset retirement obligations.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than management's estimates of its future net cash flows, including cash flows from proved reserves, risk-adjusted probable and possible reserves, and integrated assets. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates, cash flows from integrated assets and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. At December 31, 2019, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2020 price of $58.83 per barrel of oil decreasing to a 2023 price of $51.31 per barrel of oil then rising to a 2026 price of $52.57 per barrel of oil. Natural gas prices ranged from a 2020 price of $2.29 per Mcf of natural gas increasing to a 2026 price of $2.55 per Mcf of natural gas. Both oil and natural gas commodity prices for this purpose were held flat after 2026.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. During the years ended December 31, 2019, 2018 and 2017, we recognized expense of approximately $147 million, $35 million and $27 million, respectively, related to abandoned and expiring acreage, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Valuation of Stock-Based Compensation

In accordance with GAAP, we calculate the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. We utilize (i) the average of the high and low stock price on the date of grant for the fair value of restricted stock awards and (ii) the Monte Carlo simulation method for the fair value of performance unit awards. The significant assumptions used in these models include expected volatility, expected term, risk-free interest rate, forfeiture rate, dividends, and the probability of meeting performance targets. Each of these valuation methods were chosen as management believes they give the best estimate of fair value for the respective stock-based awards. See Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information regarding our stock-based compensation.

Valuation of Business Combinations

In connection with a purchase business combination, the acquiring company must record assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas properties and integrated assets. To estimate the fair values of these properties, we utilize estimates of oil and natural gas reserves. We make future price assumptions to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subject to additional project-specific risking factors. To estimate the fair value of unproved properties, we apply risk-weighting factors of the future net cash flows of unproved reserves, or we may evaluate acreage values through recent market transactions in the area.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded. Historically, we have had no material revisions to valuations of business combinations once the valuation estimate was finalized.

Accounting and Valuation of Nonmonetary Transactions

In connection with nonmonetary transactions, which include exchanges of producing and non-producing assets, we must evaluate the transaction to determine appropriate accounting treatment. In general, the basic principle of accounting for nonmonetary transactions is based on the fair values involved, which is the same basis used in monetary transactions and results in the recognition of gains and losses. However, certain nonmonetary transactions meet criteria that require modification of the basic principle that necessitate recording values based on historical book value. We determine the treatment of nonmonetary transactions based on the individual facts and circumstances of each transaction. In cases where nonmonetary transactions are recorded at fair value, we make various assumptions. The most significant assumptions are related to the estimated fair values assigned to proved and unproved oil and natural gas properties, similar to our valuation of the fair value of oil and natural gas assets acquired during a business combination described above. Any resulting difference between the fair value of the assets involved and their carrying value is recorded as a gain or loss in the consolidated statement of operations.

Estimated fair values assigned to assets exchanged can have a significant effect on our results of operations in the future. If future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value, we would record an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Impairments of Goodwill

Goodwill is assessed for impairment on an annual basis, or more frequently if indicators of impairment exist. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, is performed as of July 1 of each year. As we operate as a single operating segment and a single reporting unit, we evaluate goodwill for impairment based on an evaluation of the fair value of the company as a whole. The fair value of the reporting unit is our enterprise value (combined market capitalization of our equity plus a control premium, and the fair value of our long-term debt). There are multiple valuation methodologies available to us in determining the fair values; however, given that we are one reporting unit, we use quoted market prices in active markets as the basis for our measurement as we believe they are the best evidence of fair value. There is considerable judgment involved in estimating fair values, particularly in determining the control premium. To establish a reasonable control premium, we consider the premiums paid in recent market acquisitions and analyze current industry, market and economic conditions along with other factors or available information specific to our business. Deteriorating industry, market and economic conditions could negatively impact our control premium and our enterprise value, which could lead to an impairment of our goodwill balance.

As discussed in Note 5 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data,” in August 2019, we entered into a definitive agreement to sell our assets in the New Mexico Shelf. We classified these assets as held for sale at August 29, 2019. We allocated $81 million of goodwill to this disposal group, all of which we impaired. In addition, we performed an impairment test at September 30, 2019 due to declines in our market capitalization and at December 31, 2019 due to declines in observed control premiums. The fair value of the reporting unit at September 30, 2019 exceeded the carrying value of our net assets. However, during the fourth quarter of 2019, our fair value declined further resulting in a $201 million goodwill impairment charge at December 31, 2019.

It is reasonably possible that the estimates of our enterprise value may change in the future and result in the need to impair goodwill. Currently, the primary factors that may negatively affect our enterprise value are the continued depressed level of our stock price and estimated control premium we use in the fair value of our reporting unit. We use an average stock price over a determined period to estimate the fair value of our reporting unit, which we believe removes the impact of short-term market fluctuations. We used an average stock price of $72.23 in determining our market capitalization at December 31, 2019. In addition, our control premium is based on the estimated median control premium of transactions involving companies in our industry. Further declines in our average stock price and/or in our estimated control premium could result in additional impairments of goodwill. Many factors affecting our stock price are beyond our control and we cannot predict their potential effects on the price of our common stock. In addition, stock markets in general can experience considerable price and volume fluctuations. Other assumptions such as the control premium and the value of our long-term debt will likely change in the future, and these and other assumptions may worsen or partially mitigate some of the effects of a reduction in our average stock price. As a result, we are unable to predict with certainty whether or not a decline in our stock price alone will or will not cause us to recognize an impairment charge or the magnitude of such impairment charge.

See Notes 2 and 4 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for more information regarding goodwill.

Litigation and Environmental Contingencies

We make judgments and estimates in recording liabilities for ongoing litigation and environmental remediation. Actual costs can vary from such estimates for a variety of reasons. The costs to settle litigation can vary from estimates based on differing interpretations of laws and opinions and assessments on the amount of damages. Similarly, environmental remediation liabilities are subject to change because of changes in laws and regulations, developing information relating to the extent and nature of site contamination and improvements in technology. A liability is recorded for these types of contingencies if we determine the loss to be both probable and reasonably estimable. If we are unable to reasonably estimate an amount but we are able to estimate a range of reasonably possible amounts, then the low end of the range is recorded. See Notes 2 and 11 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for more information regarding our commitments and contingencies.

Valuation of Financial Derivatives

In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our oil and natural gas, we enter into commodity price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties’ creditworthiness. All derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net liability position with a fair value of $102 million at December 31, 2019. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates and Eurodollar futures rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on average published yields by credit rating.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2019, we reported a $895 million loss on commodity derivative instruments.

We compare our estimates of the fair values of our commodity derivative instruments with those provided by our counterparties. There have been no significant differences.

Income Taxes

On December 22, 2017, the President of the United States signed the TCJA into law, which enacted significant changes to the federal income tax laws. According to ASC 740, “Income Taxes,” a company is required to record the effects of an enacted tax law or rate change in the period of enactment. Based on the comprehensiveness of TCJA and the challenges faced by calendar year-end registrants to complete the accounting for the income tax effects of the TCJA in the period of enactment, the SEC issued SAB 118 “Income Tax Accounting Implications of the Tax Cuts and Jobs Act,” which allowed companies to report provisional amounts when based on reasonable estimates and to adjust these amounts during a measurement period of up to one year.

We elected to apply SAB 118 and recorded provisional amounts of our income tax balances in our consolidated financial statements at December 31, 2017. We calculated our best estimate of the impact of the TCJA, including the federal statutory tax rate change noted below, in our 2017 income tax provision in accordance with our understanding of the TCJA and recorded a $398 million decrease to our income tax provision at December 31, 2017. The provisional amount related to the re-measurement of certain deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future. At December 31, 2018, the Company completed its accounting for all of the enactment-date tax effects of the TCJA and recognized an adjustment of $7 million to the provisional amount recorded at December 31, 2017. This adjustment was primarily related to the deductibility of certain performance-based compensation based on additional available regulatory and interpretive guidance.

On July 19, 2018, we completed the RSP Acquisition. For federal income tax purposes, the transaction qualified as a tax-free merger whereby we acquired carryover tax basis in RSP’s assets and liabilities. As of December 31, 2018, we recorded an opening balance sheet deferred tax liability of $515 million based on our assessment of the carryover tax basis, which includes a deferred tax asset related to tax attributes acquired from RSP. The acquired income tax attributes primarily consist of NOLs and research and development credits that are subject to an annual limitation under Internal Revenue Code Section 382. The Company expects that these tax attributes will be fully utilized prior to expiration.

Our provision for income taxes includes both federal and state taxes of the jurisdictions in which we operate. We estimate our overall tax rate using a combination of the enacted federal statutory tax rate, which decreased from 35 percent to 21 percent effective

January 1, 2018 as a result of the TCJA, and a blend of enacted state tax rates. Acquisitions or dispositions of assets and changes in our drilling plan by tax jurisdiction could change the apportionment of our state taxes, which would impact our overall tax rate.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to our deferred tax liability and will affect our effective tax rate in the period it is recognized. The assessment of potential uncertain tax positions requires a significant amount of judgment and are reviewed and adjusted on a periodic basis.

Our federal and state income tax returns are not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities and tax attributes, which are based on numerous judgments and assumptions inherent in the determination of taxable income, at the end of each period. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Historically, we have had no significant changes as a result of filing our tax returns. Material changes to our tax accruals and uncertain tax positions may occur in the future based on audits, changes in legislation or resolution of pending matters.

See Note 12 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our current year income tax benefit, deferred tax balances and uncertain tax positions.

New accounting pronouncements issued but not yet adopted. See Note 2 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding new accounting pronouncements issued but not yet adopted.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks, including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at December 31, 2019, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries and, to a lesser extent, our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set-off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 9 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities, we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management arrangements are recorded at fair value and thus changes to the future commodity prices will have an impact on our earnings. The following table sets forth the hypothetical impact on the fair value of the commodity price risk management arrangements from an average increase and decrease in the commodity price of $5.00 per Bbl of oil and $0.50 per MMBtu of natural gas from the average commodity prices for the years ended December 31, 2019 and 2018:

	2019		2018	
(in millions)	**Increase of $5.00 per Bbl and $0.50 per MMBtu**	**Decrease of $5.00 per Bbl and $0.50 per MMBtu**	**Increase of $5.00 per Bbl and $0.50 per MMBtu**	**Decrease of $5.00 per Bbl and $0.50 per MMBtu**
Gain (loss):				
Oil derivatives	$ (369)	$ 369	$ (369)	$ 370
Natural gas derivatives	(82)	82	(37)	37
Total	$ (451)	$ 451	$ (406)	$ 407

Our commodity price risk management arrangements expose us to risk of non-performance by the counterparty to the agreements. Our exposure to the risk of non-performance is diversified over large, investment grade financial institutions. In addition, we have master netting agreements with the counterparties that allow for offsetting payables against receivables from separate contracts with the same counterparty. At December 31, 2019, the counterparties to our commodity price risk management arrangements include 14 financial institutions, the majority of which are lenders under our Credit Facility. Risk of non-performance is considered when determining the fair value of our commodity price risk management arrangements. The fair value adjustment for non-performance risk was immaterial at December 31, 2019. If at any point a counterparty's financial position deteriorates, such deterioration could have a significant impact on the collectability of that counterparty's related commodity price risk management arrangement asset. See Note 9 and Note 13 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our significant derivative counterparties.

At December 31, 2019, we had (i) oil price swaps covering future oil production from January 1, 2020 through December 31, 2021 and (ii) oil basis swaps covering our Midland to Cushing basis differential from January 1, 2020 to December 31, 2021. The NYMEX oil price at December 31, 2019 was $61.06 per Bbl. At February 14, 2020, the NYMEX oil price was $52.05 per Bbl.

At December 31, 2019, we had (i) natural gas price swaps that settle on a monthly basis covering future natural gas production from January 1, 2020 to December 31, 2021 and (ii) natural gas basis swaps covering our El Paso Permian to Henry Hub and

WAHA to Henry Hub basis differentials from January 1, 2020 to December 31, 2021. The NYMEX natural gas price at December 31, 2019 was $2.19 per MMBtu. At February 14, 2020, the NYMEX natural gas price was $1.84 per MMBtu.

An increase in the average forward NYMEX oil and natural gas prices above those at December 31, 2019 would increase the fair value liability of our commodity derivative contracts from their recorded balances at December 31, 2019. Changes in the recorded fair value of our commodity derivative contracts are marked to market through earnings as gains or losses. The potential increase in our fair value liability would be recorded in earnings as a loss. However, a decrease in the average forward NYMEX oil and natural gas prices below those at December 31, 2019 would decrease the fair value liability of our commodity derivative contracts from their recorded balances at December 31, 2019. The potential decrease in our fair value liability would be recorded in earnings as a gain. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

We recorded a loss on derivatives of $895 million for the year ended December 31, 2019, compared to a gain of $832 million for the year ended December 31, 2018. The largest factor in the change from 2018 to 2019 related to the change in commodity future price curves at the respective measurement and settlement periods.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during the year ended December 31, 2019. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the year ended December 31, 2019:

(in millions)		**Commodity Derivative Instruments Net Assets (Liabilities)**
Fair value of contracts outstanding December 31, 2018	$	695
Changes in fair values (a)		(895)
Contract maturities		98
Fair value of contracts outstanding December 31, 2019 (b)	$	(102)

(a) At inception, new derivative contracts entered into by us have no intrinsic value.

(b) Represents the fair values of open derivative contracts subject to market risk.

See Note 9 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our derivative instruments.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we may, in the future, enter into interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable-rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We had no outstanding interest rate derivative contracts at December 31, 2019. We are exposed to changes in interest rates as a result of our Credit Facility, and the terms of our Credit Facility require us to pay higher interest rate margins as our credit ratings decrease.

We had no indebtedness outstanding under our Credit Facility at December 31, 2019.

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Consolidated Financial Statements of Concho Resources Inc.:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Concho Resources Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 19, 2020 expressed an unqualified opinion.

Basis for opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the 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 supporting the amounts and disclosures in the 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matters
The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

Depletion and impairment of oil and natural gas properties
As described further in Note 2 to the financial statements, depletion and impairment of oil and natural gas properties involve judgments and estimates related to the Company's oil and natural gas reserve quantities and associated future net cash flows. We identified depletion and impairment of oil and natural gas properties as a critical audit matter.

The principal considerations for our determination that depletion and impairment of oil and natural gas properties is a critical audit matter are due to the high risk of estimation uncertainty of the Company's oil and natural gas reserve quantities and associated future net cash flows, which are key inputs within the Company's depletion calculations and impairment analyses. The estimates of oil and natural gas reserve quantities and associated future net cash flows include management's use of internal petroleum engineers and independent petroleum engineers and geologists (referred to as "management's specialists").

Our audit procedures related to depletion and impairment of oil and natural gas properties included the following, among others.

- We tested the Company's key inputs and assumptions used to estimate reserve quantities and future net cash flows, which include estimates of oil and natural gas prices, production costs, capital expenditures, division of interests, and the future estimated revenues based upon historical results and recent performance.
- We obtained the Company's oil and natural gas reserve reports prepared by management's specialists and performed disaggregated analytical procedures to assess the reasonableness of the Company's estimates.
- We performed substantive testing on a sample of the data used by management's specialists for reasonableness and accuracy.
- We tested the Company's depletion calculations and impairment analyses that included these oil and natural gas reserve quantities and future net cash flows.
- We evaluated the level of knowledge, skill, and ability of management's specialists and their relationship to the Company and made inquiries of management's specialists regarding the process followed and judgments used to estimate the Company's oil and natural gas reserves.

- We tested the design and operating effectiveness of key controls related to oil and natural gas reserve estimates, depletion and impairment of oil and natural gas properties.

Nonmonetary transactions
As described further in Notes 2 and 5 to the financial statements, the Company completed multiple nonmonetary transactions, involving exchanges of both proved and unproved oil and natural gas properties. Certain of these transactions resulted in the Company recording the fair value of the assets and liabilities acquired and the recognition of non-cash gains and losses. We identified nonmonetary transactions as a critical audit matter.

The principal considerations for our determination that nonmonetary transactions is a critical audit matter are due to the high risk of estimation uncertainty of the fair value of proved and unproved oil and natural gas properties exchanged. These estimates of fair value are significantly based on the Company's estimates of oil and natural gas reserve quantities and associated future net cash flows, which include management's use of internal petroleum engineers (referred to as "management's specialists").

Our audit procedures related to nonmonetary transactions included the following, among others.

- We obtained and inspected the contractual arrangements and the Company's technical accounting documentation for the transactions tested.
- We tested the Company's key inputs and assumptions used to estimate reserve quantities and future net cash flows, which include estimates of oil and natural gas prices, production costs, division of interests, and the future estimated revenues based upon historical results and recent performance for properties received and divested.
- We obtained the Company's oil and natural gas reserves and performed disaggregated analytical procedures to assess the reasonableness of the Company's estimates.
- We performed substantive testing on a sample of the data used by management's specialists for reasonableness and accuracy.
- We tested the Company's estimated fair value of unproved oil and natural gas properties exchanged based on available market data.
- We utilized a valuation specialist to assist in the evaluation of these fair value estimates.
- We evaluated the level of knowledge, skill, and ability of management's specialists and their relationship to the Company and made inquiries of management's specialists regarding the process followed and judgments used to estimate the Company's oil and natural gas reserves.
- We tested the design and operating effectiveness of key controls related to nonmonetary transactions.

Goodwill impairment
As described further in Note 2 to the financial statements, goodwill is assessed for impairment on an annual basis, or more frequently if indicators of impairment exist. The balance of goodwill is allocated in its entirety to the Company's one reporting unit. We identified goodwill impairment as a critical audit matter.

The principal considerations for our determination that goodwill impairment is a critical audit matter are due to the high risk of estimation uncertainty related to the estimated fair value of the business operations with which goodwill is associated. The fair value estimate is based on the Company's enterprise value calculated as the combined market capitalization of the Company's equity, which includes a control premium, plus the fair value of the Company's long-term debt. Changes in the estimates and judgments could have a significant impact on the fair value of the Company and the resulting amount of any goodwill impairment. Auditing management's estimates and judgments regarding the Company's stock prices, control premiums used, and the fair value of long-term debt involved a high degree of auditor subjectivity and required an increased extent of effort when performing audit procedures to evaluate the reasonableness of management's estimates and assumptions, including the need to involve a valuation specialist.

Our audit procedures related to goodwill impairment included the following, among others.

- We obtained and tested the Company's key inputs and assumptions used to estimate the Company's enterprise value.
- We obtained market evidence to evaluate the estimated fair value of the Company's equity, including historical stock price information and control premiums of recent stock transactions.
- We obtained market evidence to evaluate the estimated fair value of the Company's long-term debt.
- We utilized a valuation specialist to assist in the evaluation of these fair value estimates.
- We tested the design and operating effectiveness of key controls related to goodwill impairment.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2004.

Oklahoma City, Oklahoma
February 19, 2020

GLOSSARY OF TERMS

The following terms are used throughout this report:

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.
Bcf	One billion cubic feet of natural gas.
Boe	One barrel of oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or condensate.
Basin	A large natural depression on the earth's surface in which sediments accumulate.
Brent	Brent oil price, a major trading classification of sweet light oil that serves as a benchmark price for purchases of oil worldwide.
Development wells	Wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry hole	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses, taxes and the royalty burden.
Exploratory wells	Wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
GAAP	Generally Accepted Accounting Principles in the United States of America.
Gross wells	The number of wells in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.
Infill drilling	Drilling into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.
LIBOR	London Interbank Offered Rate, which is a market rate of interest.
MBbl	One thousand barrels of oil, condensate or natural gas liquids.
MBoe	One thousand Boe.
Mcf	One thousand cubic feet of natural gas.
MMBoe	One million Boe.
MMBtu	One million British thermal units.
MMcf	One million cubic feet of natural gas.
NYMEX	The New York Mercantile Exchange.
NYSE	The New York Stock Exchange.
Net acres	The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres.
Net wells	The total of fractional working interests owned in gross wells.
PV-10	When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10 percent. PV-10 is a non-GAAP financial measure.
Productive wells	Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.
Proved developed reserves	Proved developed reserves are proved reserves that can be expected to be recovered:

(i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

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

Supplemental definitions from the 2007 Petroleum Resources Management System:

Proved Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Proved Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Proved reserves

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) the area identified by drilling and limited by fluid contacts, if any, and

(B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated 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.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves

Proved undeveloped oil and natural gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

	(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
	(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years from initial booking, unless the specific circumstances justify a longer time.
Recompletion	The addition of production from another interval or formation in an existing wellbore.
Reservoir	A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.
Spacing	The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.
Standardized Measure	The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with FASB guidelines, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.
Undeveloped acreage	Acreage owned or leased on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Wellbore	The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called a well or borehole.
Working interest	The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.
Workover	Operations on a producing well to restore or increase production.
WTI	West Texas Intermediate - light, sweet blend of oil produced from fields in western Texas.

Concho Resources Inc.
Consolidated Balance Sheets

(in millions, except share and per share amounts)	December 31, 2019	2018
Assets		
Current assets:		
Cash and cash equivalents	$ 70	$ —
Accounts receivable, net of allowance for doubtful accounts:		
Oil and natural gas	584	466
Joint operations and other	304	365
Inventory	30	35
Derivative instruments	6	484
Prepaid costs and other	61	59
Total current assets	1,055	1,409
Property and equipment:		
Oil and natural gas properties, successful efforts method	28,785	31,706
Accumulated depletion and depreciation	(7,895)	(9,701)
Total oil and natural gas properties, net	20,890	22,005
Other property and equipment, net	437	308
Total property and equipment, net	21,327	22,313
Deferred loan costs, net	7	10
Goodwill	1,917	2,224
Intangible assets, net	17	19
Noncurrent derivative instruments	11	211
Other assets	398	108
Total assets	$ 24,732	$ 26,294
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable - trade	$ 53	$ 50
Book overdrafts	—	159
Revenue payable	268	253
Accrued drilling costs	386	574
Derivative instruments	112	—
Other current liabilities	363	320
Total current liabilities	1,182	1,356
Long-term debt	3,955	4,194
Deferred income taxes	1,654	1,808
Noncurrent derivative instruments	7	—
Asset retirement obligations and other long-term liabilities	152	168
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Common stock, $0.001 par value; 300,000,000 authorized; 198,863,681 and 201,288,884 shares issued at December 31, 2019 and 2018, respectively	—	—
Additional paid-in capital	14,608	14,773
Retained earnings	3,320	4,126
Treasury stock, at cost; 1,175,026 and 1,031,655 shares at December 31, 2019 and 2018, respectively	(146)	(131)
Total stockholders' equity	17,782	18,768
Total liabilities and stockholders' equity	$ 24,732	$ 26,294

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

Concho Resources Inc.
Consolidated Statements of Operations

	Years Ended December 31,		
(in millions, except per share amounts)	2019	2018	2017
Operating revenues:			
Oil sales	$ 4,126	$ 3,443	$ 2,092
Natural gas sales	466	708	494
Total operating revenues	4,592	4,151	2,586
Operating costs and expenses:			
Oil and natural gas production	716	590	408
Production and ad valorem taxes	349	305	199
Gathering, processing and transportation	115	55	—
Exploration and abandonments	201	65	59
Depreciation, depletion and amortization	1,964	1,478	1,146
Accretion of discount on asset retirement obligations	10	10	8
Impairments of long-lived assets	890	—	—
Impairments of goodwill	282	—	—
General and administrative (including non-cash stock-based compensation of $85, $82 and $60 for the years ended December 31, 2019, 2018 and 2017, respectively)	326	311	244
(Gain) loss on derivatives	895	(832)	126
Gain on disposition of assets, net	(170)	(800)	(678)
Transaction costs	1	39	3
Total operating costs and expenses	5,579	1,221	1,515
Income (loss) from operations	(987)	2,930	1,071
Other income (expense):			
Interest expense	(185)	(149)	(146)
Loss on extinguishment of debt	—	—	(66)
Other, net	313	108	22
Total other income (expense)	128	(41)	(190)
Income (loss) before income taxes	(859)	2,889	881
Income tax (expense) benefit	154	(603)	75
Net income (loss)	$ (705)	$ 2,286	$ 956
Earnings per share:			
Basic net income (loss)	$ (3.55)	$ 13.28	$ 6.44
Diluted net income (loss)	$ (3.55)	$ 13.25	$ 6.41

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

Concho Resources Inc.
Consolidated Statements of Stockholders' Equity

(in millions, except share data)	Common Stock Issued Shares (in thousands)	Common Stock Issued Amount	Additional Paid-in Capital	Retained Earnings	Treasury Stock Shares (in thousands)	Treasury Stock Amount	Total Stockholders' Equity
BALANCE AT JANUARY 1, 2017	146,489	$ —	$ 6,791	$ 884	430	$ (44)	$ 7,631
Net income	—	—	—	956	—	—	956
Common stock issued in business combinations	2,177	—	291	—	—	—	291
Stock options exercised	20	—	—	—	—	—	—
Grants of restricted stock	490	—	—	—	—	—	—
Performance unit share conversion	249	—	—	—	—	—	—
Cancellation of restricted stock	(100)	—	—	—	—	—	—
Stock-based compensation	—	—	60	—	—	—	60
Purchase of treasury stock	—	—	—	—	168	(23)	(23)
BALANCE AT DECEMBER 31, 2017	149,325	—	7,142	1,840	598	(67)	8,915
Net income	—	—	—	2,286	—	—	2,286
Common stock issued in business combinations	50,915	—	7,549	—	—	—	7,549
Grants of restricted stock	687	—	—	—	—	—	—
Performance unit share conversion	447	—	—	—	—	—	—
Cancellation of restricted stock	(85)	—	—	—	—	—	—
Stock-based compensation	—	—	82	—	—	—	82
Purchase of treasury stock	—	—	—	—	434	(64)	(64)
BALANCE AT DECEMBER 31, 2018	201,289	—	14,773	4,126	1,032	(131)	18,768
Net loss	—	—	—	(705)	—	—	(705)
Common stock repurchased and retired	(3,300)	—	(250)	—	—	—	(250)
Grants of restricted stock	776	—	—	—	—	—	—
Performance unit share conversion	246	—	—	—	—	—	—
Cancellation of restricted stock	(147)	—	—	—	—	—	—
Stock-based compensation	—	—	85	—	—	—	85
Common stock dividends ($0.50 per share)	—	—	—	(101)	—	—	(101)
Purchase of treasury stock	—	—	—	—	143	(15)	(15)
BALANCE AT DECEMBER 31, 2019	198,864	$ —	$ 14,608	$ 3,320	1,175	$ (146)	$ 17,782

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

Concho Resources Inc.
Consolidated Statements of Cash Flows

(in millions)	Years Ended December 31, 2019	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (705)	$ 2,286	$ 956
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,964	1,478	1,146
Accretion of discount on asset retirement obligations	10	10	8
Impairments of long-lived assets	890	—	—
Impairments of goodwill	282	—	—
Exploration and abandonments	166	35	27
Non-cash stock-based compensation expense	85	82	60
Deferred income taxes	(154)	605	(71)
Net gain on disposition of assets and other non-operating items	(459)	(800)	(678)
(Gain) loss on derivatives	895	(832)	126
Net settlements received from (paid on) derivatives	(98)	(218)	79
Loss on extinguishment of debt	—	—	66
Other	—	(92)	(1)
Changes in operating assets and liabilities, net of acquisitions and dispositions:			
Accounts receivable	(90)	(35)	(126)
Prepaid costs and other	(2)	(10)	(9)
Inventory	1	(12)	—
Accounts payable	3	1	14
Revenue payable	28	52	52
Other current liabilities	20	8	46
Net cash provided by operating activities	2,836	2,558	1,695
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and natural gas properties	(3,069)	(2,496)	(1,581)
Acquisitions of oil and natural gas properties	(54)	(136)	(908)
Additions to property, equipment and other assets	(117)	(90)	(44)
Proceeds from the disposition of assets	1,260	361	832
Direct transaction costs for asset acquisitions and dispositions	(13)	(3)	(18)
Distribution from equity method investment	—	148	—
Net cash used in investing activities	(1,993)	(2,216)	(1,719)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facility	2,935	3,316	1,001
Payments on credit facility	(3,177)	(3,396)	(679)
Issuance of senior notes, net	—	1,595	1,794
Repayments of senior notes	—	—	(2,150)
Repayments of RSP debt	—	(1,690)	—
Debt extinguishment costs	—	(83)	(63)
Payments for loan costs	—	(16)	(25)
Payment of common stock dividends	(100)	—	—
Purchases of treasury stock	(15)	(64)	(23)
Purchases of common stock under share repurchase program	(250)	—	—
Increase (decrease) in book overdrafts	(159)	(4)	116
Other	(7)	—	—
Net cash used in financing activities	(773)	(342)	(29)
Net increase (decrease) in cash and cash equivalents	70	—	(53)
Cash and cash equivalents at beginning of period	—	—	53
Cash and cash equivalents at end of period	$ 70	$ —	$ —
SUPPLEMENTAL CASH FLOWS:			
Cash paid for interest	$ 207	$ 118	$ 139

Cash paid for income taxes	$	—	$	2	$	13
NON-CASH INVESTING AND FINANCING ACTIVITIES:						
Issuance of common stock for business combinations	$	—	$	7,549	$	291

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

Concho Resources Inc.
Notes to Consolidated Financial Statements
December 31, 2019, 2018 and 2017

Note 1. ***Organization and nature of operations***

Concho Resources Inc., a Delaware corporation (the "Company") is an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. The Company's operations are primarily focused in the Permian Basin of West Texas and Southeast New Mexico.

Note 2. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its 100 percent owned subsidiaries. The consolidated financial statements also included the accounts of a variable interest entity ("VIE") where the Company was the primary beneficiary of the arrangements until the VIE structure dissolved in January 2018. See Note 5 for additional information regarding the circumstances surrounding the VIE. The Company consolidates the financial statements of these entities. All material intercompany balances and transactions have been eliminated.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2019 presentation. These reclassifications had no impact on net income (loss), total assets, liabilities and stockholders' equity or total cash flows.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties is determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves, commodity price outlooks and prevailing market rates of other sources of income and costs. Other significant estimates include, but are not limited to, asset retirement obligations, goodwill, fair value of stock-based compensation, fair value of business combinations, fair value of nonmonetary transactions, fair value of derivative financial instruments and income taxes.

Assets held for sale. On the date at which the Company determines the asset group met all of the held for sale criteria, the Company discontinues the recording of depletion and depreciation of the asset or asset group to be sold and reclassifies these assets as held for sale in its consolidated balance sheets. The assets held for sale are measured at the fair value less cost to sell.

Cash and cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company's cash and cash equivalents are generally held in financial institutions in amounts that may exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected. At December 31, 2019, the majority of the Company's cash was invested in stable value government money market funds.

Accounts receivable. The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Oil and natural gas sales receivables related to these operations are generally unsecured. Joint interest receivables are generally secured pursuant to the operating agreement between or among the co-owners of the operated property. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners and the Company's ability to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had an allowance for doubtful accounts of $7 million and $5 million for the years ended December 31, 2019 and 2018, respectively.

Inventory. Inventory consists primarily of tubular goods, water and other oilfield equipment that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of weighted average cost or net realizable value.

Oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized leasehold costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized drilling and development costs and integrated assets is based on the unit-of-production method using proved developed reserves. The Company recognized depletion expense of approximately $1.9 billion, $1.5 billion and $1.1 billion during the years ended December 31, 2019, 2018 and 2017, respectively.

Concho Resources Inc.
Notes to Consolidated Financial Statements
December 31, 2019, 2018 and 2017

The Company generally does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

(i) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and

(ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the Company's large multi-well project development program, capital intensive nature and geographical location of certain projects, it may take longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. The Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves and is transferred to proved oil and natural gas properties or is noncommercial and is charged to exploration and abandonments expense. See Note 3 for additional information regarding the Company's exploratory well costs.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire depletion base is sold. However, gain or loss is recognized from the sale of less than an entire depletion base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base. Ordinary maintenance and repair costs are expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until the related project is completed. The Company capitalizes interest on expenditures for significant development projects until such projects are ready for their intended use. During the years ended December 31, 2019 and 2018, the Company capitalized interest of $19 million and $8 million, respectively, primarily related to the Company's development projects.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. The Company reviews its oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties and integrated assets would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and risk-adjusted unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs and cash flows from integrated assets. The Company recognized an impairment expense of $890 million during the year ended December 31, 2019 related to its proved oil and natural gas properties, but did not recognize an impairment expense during the years ended December 31, 2018 and 2017. See Note 8 for additional information regarding the Company's impairment expense.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. During the years ended December 31, 2019, 2018 and 2017, the Company recognized expense of $147 million, $35 million and $27 million, respectively, related to abandoned and expiring acreage, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Other property and equipment. Other capital assets include buildings, transportation equipment, computer equipment and software, telecommunications equipment, leasehold improvements and furniture and fixtures. These items are recorded at cost, or fair value if acquired, and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two years to 39 years. The Company had other capital assets of $437 million and $308 million, net of accumulated depreciation of $126 million and $109 million, at December 31, 2019 and December 31, 2018, respectively. During the years ended December 31, 2019, 2018 and 2017, the Company recognized depreciation expense of $30 million, $22 million and $21 million, respectively.

Nonmonetary transactions. In connection with nonmonetary transactions, which include exchanges of producing and non-producing assets, the Company must evaluate the transaction to determine appropriate accounting treatment. In general, the basic principle of accounting for nonmonetary transactions is based on the fair values involved, which is the same basis used in monetary transactions and results in the recognition of gains and losses. However, certain nonmonetary transactions meet criteria that require modification of the basic principle that necessitate recording values based on historical book value. The Company determines the treatment of nonmonetary transactions based on the individual facts and circumstances of each transaction. In cases where nonmonetary transactions are recorded at fair value, the Company makes various assumptions. The most significant assumptions are related to the estimated fair values assigned to proved and unproved oil and natural gas properties, similar to the valuation of the fair value of oil and natural gas assets acquired during a business combination. Any resulting difference between the fair value of the assets involved and their carrying value is recorded as a gain or loss in the consolidated statement of operations.

Goodwill. Goodwill is assessed for impairment on an annual basis, or more frequently if indicators of impairment exist. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, are performed as of July 1 of each year. The balance of goodwill is allocated in its entirety to the Company's one reporting unit. The reporting unit's fair value is the Company's enterprise value calculated as the combined market capitalization of the Company's equity plus a control premium, and the fair value of the Company's long-term debt. If the results of the quantitative test are such that the fair value of the reporting unit is less than the carrying value, goodwill is then reduced by an amount that is equal to the amount by which the carrying value of the reporting unit exceeds the fair value.

The Company performed an annual quantitative impairment test during the third quarter of 2019. The fair value of the reporting unit exceeded the carrying value of net assets at July 1, 2019.

As discussed in Note 5, in August 2019, the Company entered into a definitive agreement to sell its assets in the New Mexico Shelf. The Company classified these assets as held for sale at August 29, 2019. The Company allocated $81 million of goodwill to this disposal group, all of which the Company impaired. This impairment charge was recorded in impairments of goodwill on the consolidated statements of operations for the year ended December 31, 2019. See Note 8 for additional impairment discussion of this disposal group. In conjunction with the allocation and impairment of goodwill related to the New Mexico Shelf disposal group, the Company performed a quantitative impairment test for the remaining goodwill. No additional impairment was recorded as the fair value of the reporting unit exceeded the carrying value.

The Company also performed an impairment test at September 30, 2019 due to declines in the Company's market capitalization and at December 31, 2019 due to declines in observed control premiums. The estimated fair value of the reporting unit at September 30, 2019 exceeded the carrying value of our net assets. However, during the fourth quarter of 2019, the Company's estimated fair value declined further resulting in a $201 million impairment charge at December 31, 2019. As such, the Company recorded total impairment charges of $282 million during the year ended December 31, 2019. The Company used an average stock price over a determined period to estimate the fair value of the reporting unit at December 31, 2019, which the Company believes removes the impact of short term market fluctuations. In addition, the Company's control premium was based on the estimated median control premium of transactions involving companies in the Company's industry. The Company did not recognize an impairment expense during the year ended December 31, 2018.

It is reasonably possible that the estimates of our enterprise value may change in the future resulting in the need to impair goodwill. Currently, the primary factor that may negatively affect the Company's enterprise value is a continued depressed level of the Company's stock price. Many factors affecting the Company's stock price are beyond the Company's control and the Company cannot predict the potential effects on the price of its common stock. Stock markets in general can also experience considerable price and volume fluctuations. In addition, deteriorating industry, market and economic conditions could negatively impact the control premium and the Company's enterprise value, which could lead to additional impairments of the Company's goodwill balance.

Equity method investments. The Company holds membership interests in certain entities and accounts for these investments using the equity method of accounting.

- The Company owns a 50 percent membership interest in Beta Holding Company, LLC, a midstream joint venture formed to construct a crude oil gathering system in the Midland Basin.
- The Company owns a 20 percent membership interest in Solaris Midstream Holdings, LLC, an entity that owns and operates water gathering, transportation, disposal, recycling and storage infrastructure assets in the Permian Basin.
- The Company owns a preferred membership interest in WaterBridge Operating LLC, an entity that operates and manages various water infrastructure assets located in the Permian Basin.

The Company includes its equity method investment balance in other assets on the consolidated balance sheets. The Company records its share of equity investment earnings and losses in other income (expense) on the consolidated statements of operations. Equity investment earnings and losses are adjusted to account for any basis difference. The Company recorded equity method investment income of $12 million, $4 million and $7 million for the years ended December 31, 2019, 2018 and 2017, respectively. The Company also contributed certain water infrastructure assets and recorded a gain of $297 million and $79 million, which is included in gain on disposition of assets, net on the Company's consolidated statements of operations for the years ended December 31, 2019 and 2018, respectively.

Until May 2019, the Company owned a 23.75 percent membership interest in Oryx Southern Delaware Holdings, LLC ("Oryx"), an entity that owned and operated Oryx I, a crude oil gathering and transportation system in the Delaware Basin ("Oryx I"). In February 2018, Oryx obtained a term loan of $800 million. The proceeds were used in part to fund a cash distribution to its equity holders, of which the Company received a distribution of $157 million. Of this amount, $54 million fully offset the Company's net investment in Oryx. The net investment of $54 million included $45 million of the Company's contributions made to Oryx and $9 million of equity income. The remaining distribution of $103 million was recorded in other income (expense) on the Company's consolidated statement of operations for the year ended December 31, 2018. In May 2019, Oryx completed the sale of 100 percent of its equity interests in Oryx I. The Company received $289 million, net of closing costs, in connection with the sale of Oryx I and recorded a gain in other income (expense) on the Company's consolidated statement of operations for the year ended December 31, 2019.

In February 2017, the Company closed on the divestiture of its 50 percent membership interest in a midstream joint venture, Alpha Crude Connector, LLC ("ACC"), that constructed a crude oil gathering and transportation system in the Delaware Basin. See Note 5 for additional information regarding the disposition of ACC.

Regulatory and environmental compliance. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Regulatory liabilities relate to acquisitions where additional equipment is necessary to have facilities compliant with local, state and federal obligations and are capitalized. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures that are noncapital in nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Environmental liabilities normally involve estimates that are subject to revisions until settlement occurs. See Note 11 for additional information.

Litigation contingencies. The Company is a party to proceedings and claims incidental to its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its consolidated financial statements. The amount of any resulting losses may differ from these estimates. An accrual is recorded for a material loss contingency when its occurrence is probable and the amount is reasonably estimable. See Note 11 for additional information.

Income taxes. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. At December 31, 2019 and 2018, the Company had unrecognized tax benefits primarily related to research and development credits. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period recognized. The timing as to when the Company will substantially resolve the uncertainties associated with the unrecognized tax benefit is uncertain. The Company has not recognized any interest or penalties relating to unrecognized tax benefits in its consolidated financial statements. Any interest or penalties would be recognized as a component of income tax expense.

On December 22, 2017, the President of the United States (the "President") signed into law the tax bill commonly referred to as the "Tax Cuts and Job Act" ("TCJA"), significantly changing federal income tax laws. According to the Accounting Standards Codification ("ASC") section 740, "Income Taxes," ("ASC 740"), a company is required to record the effects of an enacted tax law or rate change in the period of enactment, which is the date the bill is signed by the President and becomes law. As a result of the enactment of the TCJA, the U.S. Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin ("SAB") No. 118, "Income Tax Accounting Implications of the Tax Cuts and Jobs Act," ("SAB 118") to provide guidance for companies that have not completed the accounting for the income tax effects of the TCJA in the period of enactment. SAB 118 allowed companies to report provisional amounts when based on reasonable estimates and to adjust these amounts during a measurement period of up to one year. The Company elected to apply SAB 118 and, as such, recorded provisional amounts for the income tax balances reported in its consolidated financial statements at December 31, 2017. At December 31, 2018, the Company completed its accounting for all tax effects of the TCJA and made an adjustment to its provisional amounts related to the deductibility of certain compensation based on available regulatory and interpretive guidance.

Derivative instruments. The Company recognizes its derivative instruments, other than commodity derivative contracts that are designated as normal purchase and normal sale contracts, as either assets or liabilities measured at fair value. The Company nets the fair value of the derivative instruments by counterparty in the accompanying consolidated balance sheets when the right of offset exists. The Company does not have any derivatives designated as fair value or cash flow hedges. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company's consolidated balance sheets.

Asset retirement obligations. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related oil and natural gas property asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are recognized as an increase in the carrying amount of the liability through accretion expense. Based on certain factors, including commodity prices and costs, the Company may revise its previous estimates of the liability, which would also increase or decrease the related oil and natural gas property asset.

Purchases of common stock. Common stock purchased and held in treasury is recorded at cost. For common stock repurchased and retired, the excess of cost over par value is charged to additional paid-in capital.

Revenue recognition. On January 1, 2018, the Company adopted ASC Topic 606, "Revenue from Contracts with Customers," ("ASC 606") using the modified retrospective approach. The adoption did not require an adjustment to opening retained earnings for the cumulative effect adjustment and does not have a material impact on the Company's reported net income (loss), cash flows from operations or statement of stockholders' equity.

The Company recognizes revenues from the sales of oil and natural gas to its customers and presents them disaggregated on the Company's consolidated statements of operations. All revenues are recognized in the geographical region of the Permian Basin. Prior to the adoption of ASC 606, the Company recorded oil and natural gas revenues at the time of physical transfer of such products to the purchaser, which for the Company is primarily at the wellhead. The Company followed the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company's actual proceeds from the oil and natural gas sold to purchasers.

The Company enters into contracts with customers to sell its oil and natural gas production. Revenue on these contracts is recognized in accordance with the five-step revenue recognition model prescribed in ASC 606. Specifically, revenue is recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production. At December 31, 2019 and 2018, the Company had receivables related to contracts with customers of $584 million and $466 million, respectively.

Oil Contracts. The majority of the Company's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. The majority of the oil produced is sold under contracts using market-based pricing which is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred after the transfer of control of the oil, the differentials are included in oil sales on the statements of operations as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in gathering, processing and transportation on the Company's consolidated statements of operations and are accounted for as costs incurred directly and not netted from the transaction price.

Natural Gas Contracts. The majority of the Company's natural gas is sold at the lease location, which is generally when control of the natural gas has been transferred to the purchaser. The natural gas is sold under (i) percentage of proceeds processing contracts, (ii) fee-based contracts or (iii) a hybrid of percentage of proceeds and fee-based contracts. Under the majority of the Company's contracts, the purchaser gathers the natural gas in the field where it is produced and transports it via pipeline to natural gas processing plants where natural gas liquid products are extracted. The natural gas liquid products and remaining residue gas are then sold by the purchaser. Under the percentage of proceeds and hybrid percentage of proceeds and fee-based contracts, the Company receives a percentage of the value for the extracted liquids and the residue gas. Under the fee-based contracts, the Company receives natural gas liquids and residue gas value, less the fee component, or is invoiced the fee component. To the extent control of the natural gas transfers upstream of the transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those activities, revenue is recognized on a gross basis, and the related costs are classified in gathering, processing and transportation on the Company's consolidated statements of operations.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption in accordance with ASC 606. The exemption, as described in ASC 606-10-50-14A, applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

General and administrative expense. The Company receives fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and records such reimbursements as reductions of general and administrative expense. Such fees totaled $18 million, $19 million and $16 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Stock-based compensation. Stock-based compensation expense is recognized in the Company's financial statements on an accelerated basis over the awards' vesting periods based on their grant date fair values. Stock-based compensation awards vest over a period generally ranging from one to ten years. The Company utilizes the average of the high and low stock prices at each grant date to determine the fair value of restricted stock and the Monte Carlo simulation method to determine the fair value of performance unit awards. The Company recognizes forfeitures on stock-based compensation awards as they occur.

Recently adopted accounting pronouncements. In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, "Leases (Topic 842)" ("ASU 2016-02"), which requires all leases with a term greater than one year to be recognized on the consolidated balance sheet while maintaining similar classifications for finance and operating leases. Lease expense recognition on the consolidated statements of operations was effectively unchanged. The Company adopted this guidance on January 1, 2019. The Company made policy elections not to capitalize short-term leases for all asset classes and not to separate non-lease components from lease components for all asset classes except for vehicles. The Company also did not elect the package of practical expedients that allowed for certain considerations under the original "Leases (Topic 840)" accounting standard ("Topic 840") to be carried forward upon adoption of ASU 2016-02.

In January 2018, the FASB issued ASU No. 2018-01, "Land Easement Practical Expedient for Transition to Topic 842," which provides an optional practical expedient not to evaluate land easements that existed or expired before the adoption of ASU 2016-02 and that were not previously accounted for as leases under Topic 840. The Company enters into land easements on a routine basis as part of its ongoing operations and has many such agreements currently in place; however, the Company did not account for any land easements under Topic 840. As this guidance serves as an amendment to ASU 2016-02, the Company elected this practical expedient, which became effective upon the date of adoption of ASU 2016-02. The Company will assess any new land easements to determine whether the arrangement should be accounted for as a lease. In July 2018, the FASB issued ASU No. 2018-11, "Targeted Improvements," which provides a transition election not to restate comparative periods for the effects of applying the new lease standard. This transition election permits entities to change the date of initial application to the beginning of the year of adoption and to recognize the effects of applying the new standard as a cumulative-effect adjustment to the opening balance of retained earnings. The Company elected this transition approach, however the cumulative impact of adoption in the opening balance of retained earnings as of January 1, 2019 was zero.

The Company enters into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles, field equipment and drilling rigs. Upon adoption, the Company recognized $35 million of right-of-use assets, of which $19 million and $16 million relate to the Company's operating and finance leases, respectively, and $37 million of associated lease liabilities. See Note 11 for additional disclosures of the Company's leases.

In August 2018, the SEC issued a final rule that amends certain of its disclosure requirements that have become redundant, duplicative, overlapping, outdated or superseded, in light of other disclosure requirements, U.S. GAAP or changes in the information environment. The amendments are intended to facilitate the disclosure of information to investors and simplify compliance without significantly altering the total mix of information provided to investors. The final rule amends numerous SEC rules, items and forms covering a diverse group of topics, including, but not limited to, changes in stockholders' equity. The final rule extends the annual disclosure requirement in SEC Regulation S-X, Rule 3-04, of presenting changes in stockholders' equity to interim periods. Registrants are required to analyze changes in stockholders' equity in the form of a reconciliation for the current quarter and year-to-date interim periods and comparative periods in the prior year. In addition, the final rule requires the presentation of dividends per share to be disclosed in the statement of stockholders' equity.

New accounting pronouncements issued but not yet adopted. In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments" ("Topic 326"), which replaces the current "incurred loss" methodology for recognizing credit losses with an "expected loss" methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. In November 2018, the FASB issued ASU No. 2018-19, "Codification Improvements to Topic 326, Financial Instruments–Credit Losses," which makes amendments to clarify the scope of the guidance, including the amendment clarifying that receivables arising from operating leases are not within the scope of Topic 326. This guidance is effective for fiscal years beginning after December 15, 2019. The Company has completed the process of determining which financial assets are in scope for this new guidance and has developed an internal model to measure the expected credit losses for those balances as required by the new guidance. Financial assets in scope for the Company include oil and natural gas sales receivables and joint interest receivables. The Company adopted this new guidance on January 1, 2020 and recognized an immaterial non-cash cumulative effect adjustment to retained earnings on our opening consolidated balance sheet at the date of adoption.

In November 2018, the FASB issued ASU No. 2018-18, "Collaborative Arrangements (Topic 808): Clarifying the Interaction between Topic 808 and Topic 606" ("ASU 2018-18"), which, among other things, clarifies that (i) certain transactions between collaborative arrangement participants should be accounted for as revenue under Topic 606 when the collaborative arrangement participant is a customer in the context of a unit of account, (ii) adds unit-of-account guidance in Topic 808 to align with the guidance in Topic 606 and (iii) requires that in a transaction with a collaborative arrangement participant that is not directly related to sales to third parties, presenting the transaction together with revenue recognized under Topic 606 is precluded if the collaborative arrangement participant is not a customer. ASU 2018-18 is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. The amendments in this update should be applied retrospectively to the date of initial application of Topic 606. An entity should recognize the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings of the later of the earliest annual period presented and the annual period that includes the date of the entity's initial application of Topic 606. The Company adopted this guidance on January 1, 2020. The adoption did not have a material impact on the Company's consolidated financial statements.

In December 2019, the FASB issued ASU No. 2019-12, "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes" ("ASU 2019-12"), which simplifies various aspects of the income tax accounting guidance in ASC 740, including requirements related to the following: (i) hybrid tax regimes; (ii) the tax basis step-up in goodwill obtained in a transaction that is not a business combination; (iii) separate financial statements of entities not subject to tax; (iv) the intraperiod tax allocation exception to the incremental approach; (v) ownership changes in investments - changes from a subsidiary to an equity method investment (and vice versa); (vi) interim-period accounting for enacted changes in tax laws; and (vii) the year-to-date loss limitation in interim-period tax accounting. ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years and early adoption is permitted. If an entity early adopts these amendments in an interim period, it should reflect any adjustments as of the beginning of the annual period that includes that interim period. In addition, an entity that elects to early adopt ASU 2019-12 is required to adopt all of the amendments in the same period. The Company is currently assessing the effect that ASU 2019-12 will have on its financial position, results of operations and disclosures.

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Note 3. *Exploratory well costs*

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Unaudited Supplementary Data for the proved and unproved components of oil and natural gas properties. If the exploratory well is determined to be impaired, the well costs are charged to exploration and abandonments expense in the consolidated statements of operations.

The following table reflects the Company's net capitalized exploratory well activity during each of the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Beginning capitalized exploratory well costs	$ 523	$ 182	$ 151
Additions to exploratory well costs pending the determination of proved reserves (a)	271	581	180
Reclassifications due to determination of proved reserves	(503)	(226)	(147)
Exploratory well costs charged to expense	(6)	—	—
Disposition of wells	(7)	(14)	(2)
Ending capitalized exploratory well costs	$ 278	$ 523	$ 182

(a) Balance at December 31, 2018 includes $82 million of exploratory well costs acquired as part of the RSP Acquisition, as defined in Note 4.

The following table provides an aging at December 31, 2019 and 2018 of capitalized exploratory well costs based on the date drilling was completed:

	December 31,	
(in millions, except number of projects)	**2019**	**2018**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 263	$ 523
Capitalized exploratory well costs that have been capitalized for a period greater than one year	15	—
Total capitalized exploratory well costs	$ 278	$ 523
Number of projects with exploratory well costs that have been capitalized for a period greater than one year	2	—

The Company expects to complete three gross wells associated with two projects with $15 million of capitalized exploratory well costs greater than one year at December 31, 2019 in early 2020.

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Note 4. ***RSP Acquisition***

On July 19, 2018, the Company completed the acquisition of RSP Permian, Inc. (“RSP”) through an all-stock transaction (the “RSP Acquisition”). RSP was an independent oil and natural gas company engaged in the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. The vast majority of RSP’s acreage was located on large, contiguous acreage blocks in the core of the Midland Basin and the Delaware Basin. The acquisition added approximately 92,000 net acres. Under the terms of the Agreement and Plan of Merger (the “Acquisition Agreement”), each share of RSP common stock was converted into 0.320 of a share of the Company’s common stock. The Company issued approximately 51 million shares of common stock at a price of $148.27 per share, resulting in total consideration paid by the Company to the former RSP shareholders of approximately $7.5 billion.

In connection with the closing of the RSP Acquisition, the Company repaid outstanding principal under RSP’s revolving credit facility and redeemed and canceled all of RSP’s outstanding unsecured senior notes. See Note 10 for additional information regarding the Company’s debt activity.

In connection with the RSP Acquisition, the Company incurred $32 million of costs related to consulting, investment banking, advisory, legal and other acquisition-related fees during the year ended December 31, 2018, which are included in transaction costs in operating costs and expenses on the consolidated statements of operations. In addition, the Company acquired 670,369 shares of common stock from RSP employees for the payment of withholding taxes due on the vesting of their restricted shares pursuant to the Acquisition Agreement, resulting in an increase of $32 million in the Company’s treasury stock balance during the year ended December 31, 2018.

Purchase price allocation. The RSP Acquisition has been accounted for as a business combination, using the acquisition method. The following table represents the allocation of the total purchase price of RSP to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill. Goodwill is not deductible for income tax purposes.

The following table sets forth the Company’s final purchase price allocation:

(in millions)		
Total purchase price	**$**	**7,549**
Fair value of liabilities assumed:		
Accounts payable – trade	$	48
Accrued drilling costs		79
Current derivative instruments		10
Other current liabilities		116
Long-term debt		1,758
Deferred income taxes		515
Asset retirement obligations		20
Noncurrent derivative instruments		5
Total liabilities assumed	**$**	**2,551**
Total purchase price plus liabilities assumed	**$**	**10,100**
Fair value of assets acquired:		
Accounts receivable	$	194
Current derivative instruments		36
Other current assets		21
Proved oil and natural gas properties		4,055
Unproved oil and natural gas properties		3,565
Other property and equipment		5
Noncurrent derivative instruments		2
Implied goodwill		2,222
Total assets acquired	**$**	**10,100**

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

Oil and natural gas properties

The fair value of proved and unproved oil and natural gas properties was measured using valuation techniques that convert the future cash flows to a single discounted amount. Significant inputs to the valuation of proved and unproved oil and natural gas properties include estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average costs of capital. The Company utilized a combination of the NYMEX strip pricing and consensus pricing, adjusted for differentials, to value the reserves. The Company's estimates of commodity prices for purposes of determining discounted cash flows ranged from a 2018 price of $66.59 per barrel of oil decreasing to a 2022 price of $63.41 per barrel of oil. Similarly, natural gas prices ranged from a 2018 price of $2.80 per MMBtu then rising to a 2022 price of $3.09 per MMBtu. Both oil and natural gas commodity prices were held flat after 2022 and adjusted for inflation. The Company 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.

The fair value of asset retirement obligations totaled $20 million and is included in proved oil and natural gas properties with a corresponding liability in the table above. The fair value was determined based on a discounted cash flow model, which included assumptions of the estimated current abandonment costs, discount rate, inflation rate and timing associated with the incurrence of these costs.

The inputs used to value oil and natural gas properties and asset retirement obligations 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 the market prices and represent Level 1 inputs. The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves, implied market volatility, contract terms and prices and discount factors as of the close date of the RSP Acquisition and represent Level 2 inputs. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk and the derivative instruments in a liability position include a measure of the Company's own nonperformance risk, each based on the current published credit default swap rates.

The fair values determined for accounts receivable, accounts payable – trade, accrued drilling costs and other current liabilities were equivalent to the carrying value due to their short-term nature.

Other current liabilities include $10 million of liabilities primarily related to certain regulatory obligations.

Deferred income taxes

The RSP Acquisition qualified as a tax-free merger whereby the Company acquired carryover tax basis in RSP's assets and liabilities, adjusted 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 12 for additional discussion of deferred income taxes.

Goodwill recognized was primarily attributable to the following factors: (i) operating and administrative synergies and (ii) net deferred tax liabilities arising from the differences between the purchase price allocated to RSP's assets and liabilities based on fair value and the tax basis of these assets and liabilities. For the operating and administrative synergies, the total consideration for the RSP Acquisition included a control premium, which resulted in a higher value compared to the fair value of net assets acquired. There are also other qualitative assumptions of long-term factors that the RSP Acquisition creates for the Company's stockholders, including additional potential for exploration and development opportunities and additional scale and efficiencies in basins in which the Company operates.

Approximately $506 million of operating revenues and $274 million of income from operations attributed to the RSP Acquisition are included in the Company's results of operations from the closing date on July 19, 2018 through December 31, 2018.

Pro forma data. The following unaudited pro forma combined condensed financial data for the years ended December 31, 2018 and 2017 was derived from the historical financial statements of the Company giving effect to the RSP Acquisition, as if it had occurred on January 1, 2017. The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for RSP's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including (i) the Company's common stock issued to convert RSP's outstanding shares of common stock and equity awards as of the closing date of the RSP Acquisition, (ii) the depletion of RSP's fair-valued proved oil and gas properties and (iii) the estimated tax impacts of the pro forma adjustments.

Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company of $32 million for the year ended December 31, 2018 and acquisition-related costs incurred by RSP and severance payments to certain RSP employees that totaled $56 million for the year ended December 31, 2018. The pro forma results of operations do not include any cost savings or other synergies that may result from the RSP Acquisition. The pro forma financial data does not include the pro forma results of operations for any other acquisitions made during the period. The pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the RSP Acquisition taken place on January 1, 2017 and is not intended to be a projection of future results.

	Years Ended December 31,	
(in millions, except per share amounts)	**2018**	**2017**
	(unaudited)	
Operating revenues	$ 4,798	$ 3,390
Net income	$ 2,552	$ 1,197
Earnings per share:		
Basic net income	$ 12.75	$ 6.02
Diluted net income	$ 12.73	$ 5.99

Note 5. *Acquisitions, divestitures and nonmonetary transactions*

During the year ended December 31, 2019, the Company closed on the following transactions:

New Mexico Shelf divestiture. On August 29, 2019, the Company entered into a definitive agreement to sell its assets in the New Mexico Shelf. The Company determined these assets and liabilities to be held for sale at August 29, 2019 and recorded an impairment charge of $3 million, included in impairments of long-lived assets on the Company's consolidated statement of operations for the year ended December 31, 2019, to reduce the carrying value of these assets to their estimated fair value less costs to sell. This transaction closed in November 2019 for total proceeds of $837 million, subject to post-closing adjustments. The Company recorded a pre-tax loss of $27 million, included in gain on disposition of assets, net on the Company's consolidated statement of operations for the year ended December 31, 2019. Additionally, the Company impaired the carrying value of goodwill by $81 million, reflecting the portion of the Company's goodwill allocated to the assets sold.

Nonmonetary transactions. During 2019, the Company completed multiple nonmonetary transactions. These transactions included exchanges of both proved and unproved oil and natural gas properties. Certain of these transactions were accounted for at fair value and, as a result, the Company recorded net pre-tax losses of $104 million, including a $23 million reduction of the carrying value of goodwill, reflecting the portion of the Company's goodwill related to the assets sold.

During the year ended December 31, 2018, the Company closed on the following transactions (exclusive of the RSP Acquisition disclosed in Note 4):

February 2018 acquisition and divestiture. In February 2018, the Company closed on an acquisition treated as a business combination where it received producing wells with approximately 21,000 net acres, primarily located in the Midland Basin. As consideration for the non-cash acquisition, the Company divested approximately 34,000 net acres located primarily in the northern portion of the Delaware Basin. The business acquired was valued at approximately $755 million as compared to the historical book value of the divested assets of approximately $180 million, which resulted in a non-cash gain of approximately $575 million, included in gain on disposition of assets, net on the Company's consolidated statement of operations for the year ended December 31, 2018. The fair value of the assets acquired totaled approximately $755 million, which was comprised of approximately $245 million of proved properties, approximately $480 million of unproved properties and approximately $30 million of other assets. The fair value of the assets received in the business combination approximated the fair value of assets disposed.

Delaware Basin divestitures. In January 2018, the Company closed on two asset sales transactions of certain non-core assets in Reeves and Ward Counties, Texas, with combined proceeds of approximately $280 million. After direct transaction costs, the Company recorded a pre-tax gain of approximately $134 million, which is included in gain on disposition of assets, net on its consolidated statement of operations for the year ended December 31, 2018. The assets divested included proved and unproved oil and natural gas properties on approximately 20,000 net acres.

These divestitures completed a transaction structured as a reverse like-kind exchange ("Reverse 1031 Exchange") in accordance with Section 1031 of the Internal Revenue Code of 1986, as amended, that the Company entered into concurrent with its July 2017 Midland Basin acquisition, as further described below.

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Upon completion of the Reverse 1031 Exchange in January 2018, the assets and liabilities attributable to the acquisition that were held by the VIE were conveyed to the Company, and the VIE structure was dissolved.

Nonmonetary transactions. During 2018, the Company completed multiple nonmonetary transactions. These transactions included exchanges of both proved and unproved oil and natural gas properties. Certain of these transactions were accounted for at fair value and, as a result, the Company recorded pre-tax gains of approximately $15 million.

During the year ended December 31, 2017, the Company closed on the following transactions:

Delaware Basin acquisition. In January and April 2017, the Company closed on the two-part acquisition in the northern Delaware Basin. As consideration for the entire acquisition, the Company paid approximately $160 million in cash, of which $43 million was held in escrow at December 31, 2016, and issued to the seller approximately 2.2 million shares of its common stock with an approximate value of $291 million.

ACC divestiture. In February 2017, the Company closed on the divestiture of its ownership interest in ACC. The Company and its joint venture partner entered into separate agreements to sell 100 percent of their respective ownership interests in ACC. After adjustments for debt and working capital, the Company received cash proceeds from the sale of approximately $801 million. After direct transaction costs, the Company recorded a pre-tax gain on disposition of assets of approximately $655 million which is included in gain on disposition of assets, net on its consolidated statement of operations for the year ended December 31, 2017. The Company's net investment in ACC at the time of closing was approximately $129 million.

Midland Basin acquisition. In July 2017, the Company completed an acquisition in the Midland Basin. As consideration for the acquisition, the Company paid approximately $595 million in cash.

Concurrent with the acquisition, the Company entered into a transaction structured as a Reverse 1031 Exchange. In connection with the Reverse 1031 Exchange, the Company assigned the ownership of the oil and natural gas properties acquired to a VIE formed by an exchange accommodation titleholder. The Company operated the properties pursuant to a management agreement with the VIE. At December 31, 2017, the Company was determined to be the primary beneficiary of the VIE, as the Company had the ability to control the activities that most significantly impact the VIE's economic performance. The assets held by the VIE attributable to the acquisition were conveyed to the Company and the VIE structure terminated upon the completion of the Reverse 1031 Exchange.

Nonmonetary transactions. During 2017, the Company completed multiple nonmonetary transactions. The transactions included exchanges of both proved and unproved oil and natural gas properties. Certain of these transactions were accounted for at fair value and as a result the Company recorded pre-tax gains totaling approximately $26 million.

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Note 6. *Asset retirement obligations*

The Company's asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

The Company's asset retirement obligation transactions during the years ended December 31, 2019, 2018 and 2017 are summarized in the table below:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Asset retirement obligations, beginning of period	$ 179	$ 141	$ 130
Liabilities incurred from new wells	7	4	2
Liabilities assumed in acquisitions	4	26	10
Accretion expense	10	10	8
Disposition of wells	(66)	(4)	(1)
Liabilities settled upon plugging and abandoning wells	(7)	(7)	(5)
Revision of estimates (a)	12	9	(3)
Asset retirement obligations, end of period	$ 139	$ 179	$ 141

(a) The revisions to the Company's asset retirement obligation estimates for the years ended December 31, 2019 and 2018 were primarily due to increased costs in New Mexico.

Note 7. *Incentive plans*

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of its employees. During the years ended December 31, 2019, 2018 and 2017, the Company matched 100 percent of employee contributions, not to exceed 10 percent of the employee's annual eligible compensation, subject to federal limits. The Company's contributions to the plan for the years ended December 31, 2019, 2018 and 2017 were $15 million, $12 million and $10 million, respectively.

Stock incentive plan. On May 16, 2019, the Company's stockholders approved and adopted the Company's 2019 Stock Incentive Plan ("the Plan"), which, among other things, increased the total shares authorized for issuance from 10.5 million to 15.0 million. At December 31, 2019, the Company had 5.0 million shares of common stock available for future grants. Shares issued as a result of awards granted under the Plan are generally new common shares.

Restricted stock awards. All restricted shares are legally issued and outstanding. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and canceled and are no longer considered issued and outstanding. A summary of the Company's restricted stock award activity for the year ended December 31, 2019 is presented below:

	Number of Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Outstanding at December 31, 2018	1,364,699	$ 128.08
Shares granted	776,189	$ 98.83
Shares cancelled / forfeited	(147,336)	$ 113.69
Lapse of restrictions	(508,200)	$ 126.82
Outstanding at December 31, 2019	1,485,352	$ 113.74

For restricted stock awards granted, stock-based compensation expense is recognized in the Company's consolidated financial statements on an accelerated basis over the awards' vesting periods based on their grant date fair values. The restricted stock-based compensation awards generally vest over a period ranging from one to ten years. The Company utilizes the average of the high and low stock prices on the grant date for the fair value of restricted stock.

The following table summarizes information about stock-based compensation for the Company's restricted stock awards activity under the Plan for the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Fair value for awards granted during the period (a)	$ 77	$ 94	$ 60
Fair value for awards vested during the period	$ 52	$ 54	$ 49
Stock-based compensation expense from restricted stock	$ 63	$ 60	$ 43
Income tax benefit related to restricted stock	$ 10	$ 14	$ 11

(a) The weighted average grant date fair value per share amounts were $98.83, $137.31 and $123.16 for the years ended December 31, 2019, 2018 and 2017, respectively.

Performance unit awards. During the years ended December 31, 2019, 2018 and 2017, the Company awarded performance units to its officers under the Plan. The number of shares of common stock that will ultimately be issued will be determined by a combination of (i) comparing the Company's total shareholder return relative to the total shareholder return of a predetermined group of peer companies at the end of the performance period and (ii) the Company's absolute total shareholder return at the end of the performance period. Other than the performance units with a five-year performance period described below, the performance period is typically 3 years.

In January 2019, the Company granted 212,947 performance unit awards. Included in this grant were 38,952 performance unit awards granted to certain officers, of which 19,476 have a three-year performance period and 19,476 have a five-year performance period. For these 38,952 performance unit awards, at the end of each performance period, each of these performance unit awards will convert into a restricted stock award with the number of shares determined based upon performance criteria, which will then vest at a rate of 20 percent per year commencing on the sixth anniversary of the grant date. All other performance unit awards granted during 2019 will vest at the end of a three-year performance period.

The grant date fair value is determined using the Monte Carlo simulation method and is expensed ratably over the performance period. Expected volatilities utilized in the model were estimated using a historical period consistent with the remaining performance period. The risk-free interest rate was based on the U.S. Treasury rate for a term commensurate with the expected life of the grant.

The Company used the following assumptions to estimate the fair value of performance unit awards granted during the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
	2019	**2018**	**2017**
Risk-free interest rate	2.45% - 2.47%	2.00%	1.47%
Range of volatilities	23.3% - 50.0%	23.5% - 64.0%	24.8% - 60.2%

The following table summarizes the performance unit activity for the year ended December 31, 2019:

	Number of Units		Grant Date Fair Value
Performance units:			
Outstanding at December 31, 2018	218,391	$	201.97
Units granted (a)	212,947	$	144.03
Lapse of restrictions (b)	(106,901)	$	187.31
Outstanding at December 31, 2019	324,437	$	168.77

(a) Includes 38,952 performance unit awards granted to certain officers in January 2019 that may convert into shares of restricted stock awards at the end of each performance period that will be subject to additional vesting conditions.

(b) On December 31, 2019, the performance period ended for these performance units. Each unit converted into 0.38 shares representing 40,631 shares of common stock issued on January 2, 2020.

The following table summarizes information about stock-based compensation expense for performance units for the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,					
(in millions)		**2019**		**2018**		**2017**
Fair value for awards granted during the period (a)	$	31	$	24	$	20
Fair value for awards vested during the period	$	26	$	68	$	68
Stock-based compensation expense from performance units	$	22	$	22	$	17
Income tax benefit related to performance units	$	5	$	14	$	2

(a) The weighted average grant date fair value per unit amounts were $144.03, $216.03 and $183.48 for the years ended December 31, 2019, 2018 and 2017, respectively.

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at December 31, 2019:

(in millions)		
2020	$	61
2021		36
2022		12
2023		2
2024		1
Thereafter		2
Total	$	114

Note 8. ***Disclosures about fair value measurements***

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

***Level 1*:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

***Level 2*:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, collars and floors, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

***Level 3*:** Prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

Financial Assets and Liabilities Measured at Fair Value

The following table presents the carrying amounts and fair values of the Company's financial instruments at December 31, 2019 and 2018:

	December 31, 2019		December 31, 2018	
(in millions)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Assets:				
Derivative instruments	$ 17	$ 17	$ 695	$ 695
Liabilities:				
Derivative instruments	$ 119	$ 119	$ —	$ —
Credit facility	$ —	$ —	$ 242	$ 242
$600 million 4.375% senior notes due 2025 (a)	$ 595	$ 620	$ 594	$ 591
$1,000 million 3.75% senior notes due 2027 (a)	$ 990	$ 1,054	$ 989	$ 939
$1,000 million 4.3% senior notes due 2028 (a)	$ 989	$ 1,091	$ 988	$ 980
$800 million 4.875% senior notes due 2047 (a)	$ 789	$ 941	$ 789	$ 761
$600 million 4.85% senior notes due 2048 (a)	$ 592	$ 697	$ 592	$ 573

(a) The carrying value includes associated deferred loan costs and any discount.

Credit facility. The carrying amount of the Company's amended and restated credit facility ("Credit Facility") approximates its fair value, as the applicable interest rates are variable and reflective of market rates.

Senior notes. The fair values of the Company's senior notes are based on quoted market prices. The debt securities are not actively traded and, therefore, are classified as Level 2 in the fair value hierarchy.

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Other financial assets and liabilities. The Company has other financial instruments consisting primarily of receivables, payables and other current assets and liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Derivative instruments. The fair value of the Company's derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following tables summarize (i) the valuation of each of the Company's financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets at December 31, 2019 and 2018. The Company nets the fair value of derivative instruments by counterparty in the Company's consolidated balance sheets.

	December 31, 2019					
	Fair Value Measurements Using					
(in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:						
Commodity derivatives	$ —	$ 108	$ —	$ 108	$ (102)	$ 6
Noncurrent:						
Commodity derivatives	—	31	—	31	(20)	11
Liabilities						
Current:						
Commodity derivatives	—	(214)	—	(214)	102	(112)
Noncurrent:						
Commodity derivatives	—	(27)	—	(27)	20	(7)
Net derivative instruments	$ —	$ (102)	$ —	$ (102)	$ —	$ (102)

	December 31, 2018					
	Fair Value Measurements Using					
(in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:						
Commodity derivatives	$ —	$ 543	$ —	$ 543	$ (59)	$ 484
Noncurrent:						
Commodity derivatives	—	243	—	243	(32)	211
Liabilities						
Current:						
Commodity derivatives	—	(59)	—	(59)	59	—
Noncurrent:						
Commodity derivatives	—	(32)	—	(32)	32	—
Net derivative instruments	$ —	$ 695	$ —	$ 695	$ —	$ 695

Concentrations of credit risk. At December 31, 2019, the Company's primary concentrations of credit risk are the risk of collecting accounts receivable and the risk of counterparties' failure to perform under derivative obligations. See Note 13 for information regarding the Company's major customers and derivative counterparties.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 9 for additional information regarding the Company's derivative activities.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company's consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets. The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. The Company reviews its oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of the Company's assets, it recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

At June 30, 2019, the carrying amount of the proved properties of the Company's Yeso field exceeded the expected undiscounted future net cash flows resulting in an impairment charge against earnings of $868 million, reducing the carrying value of the Yeso field to its estimated fair value of $968 million. This impairment charge represented the amount by which the carrying amount exceeded the estimated fair value of the assets and was attributable primarily to certain downward adjustments to the Company's economically recoverable proved oil and natural gas reserves. Additionally, during the third quarter of 2019, the Company further impaired the Yeso Field due to the decrease in future commodity prices and recorded an additional impairment charge of $20 million. These impairment charges were included in impairments of long-lived assets on the consolidated statement of operations for the year ended December 31, 2019.

At December 31, 2019, the expected undiscounted future net cash flows were greater than the carrying amounts of the Company's assets and no additional impairment was recorded.

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The assumptions used in calculating the estimated fair value of the Yeso field at June 30, 2019 and the Company's assets at December 31, 2019 are below.

The Company calculates the expected undiscounted future net cash flows of its long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets.

At June 30, 2019, the Company's estimates of commodity prices for purposes of determining undiscounted future cash flows, which were based on the NYMEX strip, ranged from a 2019 price of $58.32 per barrel of oil decreasing to a 2022 price of $53.58 then rising to a 2026 price of $54.47 per barrel of oil. Natural gas prices ranged from a 2019 price of $2.38 per Mcf of natural gas increasing to a 2026 price of $2.99 per Mcf. Both oil and natural gas commodity prices for this purpose were held flat after 2026.

At December 31, 2019, the Company's estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2020 price of $58.83 per barrel of oil decreasing to a 2023 price of $51.31 per barrel of oil then rising to a 2026 price of $52.57 per barrel of oil. Natural gas prices ranged from a 2020 price of $2.29 per Mcf of natural gas increasing to a 2026 price of $2.55 per Mcf of natural gas. Both oil and natural gas commodity prices for this purpose were held flat after 2026. The Company did not recognize any impairment loss during the years ended December 31, 2018 or 2017.

The Company calculates the estimated fair values of its long-lived assets and their integrated assets using a discounted future cash flow model. Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices, and (v) a market-based weighted average cost of capital. The Company utilized a combination of the NYMEX strip pricing and consensus pricing, adjusted for differentials, to value the reserves. These are classified as Level 3 fair value assumptions.

At June 30, 2019, the Company's estimate of commodity prices for purposes of determining discounted future cash flows ranged from a 2019 price of $58.32 per barrel of oil increasing to a 2026 price of $62.06 per barrel of oil. Natural gas prices ranged from a 2019 price of $2.38 per Mcf of natural gas increasing to a 2026 price of $3.00 per Mcf of natural gas. These prices were then adjusted for location and quality differentials. Both oil and natural gas commodity prices for this purpose were inflated by two percent each year after 2026. The expected future net cash flows were discounted using a rate of 10 percent.

At December 31, 2019, the Company's estimate of commodity prices for purposes of determining discounted future cash flows ranged from a 2020 price of $58.83 per barrel of oil decreasing to a 2021 price of $54.38 per barrel of oil then rising to a 2026 price of $59.01 per barrel of oil. Natural gas prices ranged from a 2020 price of $2.29 per Mcf of natural gas increasing to a 2026 price of $2.63 per Mcf of natural gas. These prices were then adjusted for location and quality differentials. Both oil and natural gas commodity prices for this purpose were inflated by two percent each year after 2026. The expected future net cash flows were discounted using a rate of 10 percent.

It is reasonably possible that the estimate of undiscounted future net cash flows of the Company's long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity prices including differentials, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities, and (v) changes in income and expenses from integrated assets.

Assets held for sale. The Company's Yeso field was primarily composed of the New Mexico Shelf assets that the Company sold in November 2019. The assets and liabilities associated with the New Mexico Shelf divestiture were classified as held for sale at August 29, 2019 and were measured at their estimated fair value less cost to sell. The related fair value at August 29, 2019 was based upon anticipated sales proceeds less costs to sell. Because the Company's closing and post-closing adjustments, primarily revenues and operating expenses, used to calculate the fair value less costs to sell were estimates that were both significant and unobservable, they were considered Level 3 fair value measurements. This transaction closed in November 2019 for total proceeds of $837 million, subject to additional post-closing adjustments. Refer to Note 5 for additional information related to the New Mexico Shelf asset divestiture.

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Note 9. ***Derivative financial instruments***

The Company uses derivative financial instruments to manage its exposure to commodity price fluctuations. Commodity derivative instruments are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company's capital budget and expenditure plans and (iii) support the economics associated with acquisitions. The Company does not enter into derivative financial instruments for speculative or trading purposes.

At December 31, 2019, the Company's derivative financial instruments consisted of oil and natural gas swaps and basis swaps. Swap contracts allow the Company to receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. Basis swap contracts allow the Company to receive a fixed price differential between market indices for the price of oil or natural gas.

In connection with the RSP Acquisition, the Company assumed certain oil collar and three-way collar contracts. In these contracts, each collar has an established floor price and ceiling price, and certain collars also include a short put price (three-way collars). When the settlement price is below the established floor price, the Company receives an amount from its counterparty equal to the difference between the settlement price and the floor price multiplied by the hedged contract volume. When the settlement price is above the established ceiling price, the Company pays its counterparty an amount equal to the difference between the settlement price and the ceiling price multiplied by the hedged contract volume. When the settlement price is between the established floor and the ceiling, no amounts are due to or from the counterparty. In case of a three-way collar, when the settlement price is below the short put price, the Company receives from its counterparty an amount equal to the difference of the floor price and the short put price multiplied by the hedged contract volume. The Company had no outstanding collars or three-way collars at December 31, 2019.

The Company also enters into fixed-price forward physical power purchase contracts to manage the volatility of the price of power needed for ongoing operations. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these physical contracts are not expected to be net cash settled, the Company has elected normal purchase or normal sale treatment and records these contracts at cost.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its consolidated statements of operations as they occur.

The following table summarizes the amounts reported in earnings related to the commodity derivative instruments for the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Gain (loss) on derivatives:			
Oil derivatives	$ (1,003)	$ 848	$ (172)
Natural gas derivatives	108	(16)	46
Total	$ (895)	$ 832	$ (126)

The following table represents the Company's net cash receipts from (payments on) derivatives for the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ (129)	$ (213)	$ 79
Natural gas derivatives	31	(5)	—
Total	$ (98)	$ (218)	$ 79

Commodity derivative contracts. The following table sets forth the Company's outstanding derivative contracts at December 31, 2019. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at December 31, 2019 are expected to settle by December 31, 2021.

	2020					
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	2021
Oil Price Swaps – WTI: (a)						
Volume (MBbl)	14,674	12,494	11,080	10,045	48,293	18,612
Price per Bbl	$ 57.13	$ 56.90	$ 56.88	$ 57.00	$ 56.98	$ 54.19
Oil Price Swaps – Brent: (b)						
Volume (MBbl)	2,578	2,031	1,768	1,503	7,880	—
Price per Bbl	$ 60.78	$ 60.33	$ 60.29	$ 60.14	$ 60.43	$ —
Oil Basis Swaps: (c)						
Volume (MBbl)	14,951	11,284	10,856	10,120	47,211	18,980
Price per Bbl	$ (0.43)	$ (0.56)	$ (0.62)	$ (0.71)	$ (0.57)	$ 0.64
Natural Gas Price Swaps – Henry Hub: (d)						
Volume (BBtu)	35,023	32,314	30,038	28,498	125,873	40,150
Price per MMBtu	$ 2.46	$ 2.46	$ 2.47	$ 2.47	$ 2.47	$ 2.52
Natural Gas Basis Swaps – Henry Hub/El Paso Permian: (e)						
Volume (BBtu)	25,770	23,960	22,080	21,770	93,580	36,500
Price per MMBtu	$ (1.06)	$ (1.07)	$ (1.07)	$ (1.07)	$ (1.07)	$ (0.66)
Natural Gas Basis Swaps – Henry Hub/WAHA: (f)						
Volume (BBtu)	7,280	7,280	7,360	7,360	29,280	10,950
Price per MMBtu	$ (1.10)	$ (1.10)	$ (1.10)	$ (1.10)	$ (1.10)	$ (0.66)

(a) These oil derivative contracts are settled based on the NYMEX – WTI calendar-month average futures price.

(b) These oil derivative contracts are settled based on the Brent calendar-month average futures price.

(c) The basis differential price is between Midland – WTI and Cushing – WTI. These contracts are settled on a calendar-month basis.

(d) The natural gas derivative contracts are settled based on the NYMEX – Henry Hub last trading day futures price.

(e) The basis differential price is between NYMEX – Henry Hub and El Paso Permian.

(f) The basis differential price is between NYMEX – Henry Hub and WAHA.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Company believes that all of its derivative counterparties are currently acceptable credit risks. The Company is not required to provide credit support or collateral to any counterparties under its derivative contracts, nor are they required to provide credit support to the Company.

In September 2017, the Company elected to enter into an "Investment Grade Period," as defined in Note 10, under the Credit Facility, which had the effect of releasing all collateral formerly securing the Credit Facility. Additionally, as a result of the Company's Investment Grade Period election along with amendments to certain ISDA Agreements with the Company's derivative counterparties, the Company's derivatives are no longer secured. See Note 10 for additional information regarding the Credit Facility.

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Note 10. *Debt*

The Company's debt consisted of the following at December 31, 2019 and 2018:

	December 31,	
(in millions)	**2019**	**2018**
Credit facility due 2022	$ —	$ 242
4.375% unsecured senior notes due 2025 (a)	600	600
3.75% unsecured senior notes due 2027	1,000	1,000
4.3% unsecured senior notes due 2028	1,000	1,000
4.875% unsecured senior notes due 2047	800	800
4.85% unsecured senior notes due 2048	600	600
Unamortized original issue discount	(9)	(10)
Senior notes issuance costs, net	(36)	(38)
Less: current portion	—	—
Total long-term debt	$ 3,955	$ 4,194

(a) For each of the twelve month periods beginning on January 15, 2020, 2021, 2022, 2023 and thereafter, these notes are callable at 103.281%, 102.188%, 101.094% and 100%, respectively.

Credit Facility. The Credit Facility has a maturity date of May 9, 2022. At December 31, 2019, the Company's commitments from its bank group were $2.0 billion.

In April 2017, the Company amended the Credit Facility to extend the maturity date and decrease unused lender commitments. The amendment also lowered the corporate ratings floor sufficient to automatically terminate an Investment Grade Period under the Credit Facility from (i) "Ba1" to "Ba2" for Moody's Investors Service, Inc. ("Moody's") and (ii) "BB+" to "BB" for S&P Global Ratings ("S&P").

In September 2017, the Company elected to enter into an Investment Grade Period under the Credit Facility, which had the effect of releasing all collateral formerly securing the Credit Facility. If the Investment Grade Period under the Credit Facility terminates (whether automatically due to a downgrade of the Company's credit ratings below certain thresholds or by the Company's election), the Credit Facility will once again be secured by a first lien on substantially all of the Company's oil and natural gas properties and by a pledge of the equity interests in its subsidiaries. At December 31, 2019, certain of the Company's 100 percent owned subsidiaries were guarantors under the Credit Facility.

During an Investment Grade Period, advances on the Credit Facility bear interest, at the Company's option, based on (i) an alternative base rate, which is equal to the highest of (a) the prime rate of JPMorgan Chase Bank (4.8 percent at December 31, 2019), (b) the federal funds effective rate plus 0.5 percent and (c) LIBOR plus 1.0 percent or (ii) LIBOR. The Credit Facility's interest rates and commitment fees on the unused portion of the available commitment vary depending on the Company's credit ratings from Moody's and S&P. At the Company's current credit ratings, LIBOR Rate Loans and Alternate Base Rate Loans bear interest margins of 150 basis points and 50 basis points per annum, respectively, and commitment fees on the unused portion of the available commitment are 25 basis points per annum. During the years ended December 31, 2019, 2018 and 2017, the Company incurred commitment fees on the unused portion of the available commitments of $4 million, $5 million and $6 million, respectively. The Company had $2.0 billion of unused commitments under the Credit Facility at December 31, 2019.

The Credit Facility contains various restrictive covenants and compliance requirements, which include:

- maintenance of certain financial ratios, including maintenance of a quarterly ratio of consolidated total debt to consolidated earnings, as defined, before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other non-cash income and expenses to be no greater than 4.25 to 1.0, and during an Investment Grade Period, if the Company does not have both a rating of "Baa3" or better from Moody's and a rating of "BBB-" or better from S&P, maintenance of a quarterly ratio of PV-9 of the Company's oil and natural gas properties reflected in its most recently delivered reserve report to consolidated total debt to be no less than 1.50 to 1.0;

- limits on the incurrence of additional indebtedness and certain types of liens;

- restrictions as to mergers, combinations and dispositions of assets; and

- restrictions on the payment of cash dividends.

Senior notes. Interest on the Company's senior notes is paid in arrears semi-annually. The senior notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's 100 percent owned subsidiaries, subject to customary release provisions as described in Note 18, and rank equally in right of payments with one another.

On July 2, 2018, the Company issued $1,600 million in aggregate principal amount of unsecured senior notes, consisting of $1,000 million in aggregate principal amount of 4.3% unsecured senior notes due 2028 (the "4.3% Notes") and $600 million in aggregate principal amount of 4.85% unsecured senior notes due 2048 (the "4.85% Notes" and, together with the 4.3% Notes, the "Notes"). The 4.3% Notes were issued at a price equal to 99.660 percent of par, and the 4.85% Notes were issued at a price equal to 99.740 percent of par. The net proceeds of $1,579 million were used to redeem and cancel all of RSP's outstanding $700 million aggregate principal amount of 6.625% unsecured senior notes due 2022 (the "RSP 2022 Notes") and $450 million aggregate principal amount of 5.25% unsecured senior notes due 2025 (the "RSP 2025 Notes" and, together with the RSP 2022 Notes, the "RSP Notes"). The Company made aggregate payments of approximately $1.2 billion to redeem and cancel the RSP Notes, including make-whole call premiums of $35 million and $33 million for the RSP 2022 Notes and RSP 2025 Notes, respectively. The Company also paid accrued interest of $14 million on the RSP Notes. The remaining proceeds, along with borrowings under the Credit Facility, were used to repay the $540 million of outstanding principal under RSP's revolving credit facility, including $1 million in accrued interest. See Note 4 for additional information regarding the RSP Acquisition.

In September 2017, the Company issued $1,800 million in aggregate principal amount of unsecured senior notes, consisting of $1,000 million in aggregate principal amount of 3.75% unsecured senior notes due 2027 (the "3.75% Notes") and $800 million in aggregate principal amount of 4.875% unsecured senior notes due 2047 (the "4.875% Notes" and, together with the 3.75% Notes, the "2017 Notes"). The 3.75% Notes were issued at a price equal to 99.636 percent of par, and the 4.875% Notes were issued at a price equal to 99.749 percent of par. The Company received net proceeds of $1,777 million.

Additionally, in September 2017, the Company completed a cash tender offer (the "Tender Offer") to purchase any and all of the outstanding $600 million aggregate principal amount of its 5.5% unsecured senior notes due 2022 and the outstanding $1,550 million aggregate principal amount of its 5.5% unsecured senior notes due 2023 (collectively, the "5.5% Notes"). The Company received tenders from the holders of $1,232 million in aggregate principal amount, or approximately 57.3 percent, of its outstanding 5.5% Notes in connection with the Tender Offer at a price of 102.934 percent of the unpaid principal amount plus accrued and unpaid interest to the settlement date.

In connection with the Tender Offer, the Company redeemed the remaining outstanding 5.5% Notes not purchased in the Tender Offer at a price, including the make-whole premium as determined in accordance with the indentures, of 102.75 percent of the unpaid principal amount plus accrued and unpaid interest. Additionally in September 2017, the Company completed a satisfaction and discharge of the redeemed notes, where the Company prepaid interest to October 13, 2017. The Company used the net proceeds from the offering of the 2017 Notes, together with cash on hand and borrowings under its Credit Facility, to fund the Tender Offer and the redemption of its obligations under the indentures of the 5.5% Notes.

As a result of these transactions, the Company recorded a loss on extinguishment of debt of $65 million for the year ended December 31, 2017.

At December 31, 2019, the Company was in compliance with the covenants under all of its debt instruments.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at December 31, 2019 were as follows:

(in millions)		
2020	$	—
2021		—
2022		—
2023		—
2024		—
Thereafter		4,000
Total	$	4,000

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Cash payments for interest	$ 207	$ 118	$ 139
Non-cash interest	6	5	6
Net changes in accruals	(9)	34	4
Interest costs incurred	204	157	149
Less: capitalized interest	(19)	(8)	(3)
Total interest expense	$ 185	$ 149	$ 146

Note 11. *Commitments and contingencies*

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company's officers covered under such agreements total $10 million.

Indemnifications. The Company has agreed to indemnify its directors and officers with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. Assessing contingencies is highly subjective and requires judgment about uncertain future events. When evaluating contingencies related to legal proceedings, the Company may be unable to estimate losses due to a number of factors, including potential defenses, the procedural status of the matter in question, the presence of complex legal and/or factual issues, the ongoing discovery and/or development of information important to the matter. For material matters that the Company believes an unfavorable outcome is reasonably possible, it would disclose the nature of the matter and a range of potential exposure, unless an estimate cannot be made at this time. The Company does not believe that the loss for any other litigation matters and claims that are reasonably possible to occur will have a material adverse effect on its financial position, results of operations or liquidity. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any estimated accruals as appropriate.

Severance tax, royalty and joint interest audits. The Company is subject to routine severance, royalty and joint interest audits from regulatory bodies and non-operators and makes accruals as necessary for estimated exposure when deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise primarily from interpretations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, allowable costs under joint interest arrangements and other matters. Although the Company believes that it has estimated its exposure with respect to the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued.

Regulatory and environmental compliance. Regulatory liabilities relate to acquisitions where additional equipment is necessary to have facilities compliant with local, state and federal obligations. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Environmental liabilities normally involve estimates that are subject to revision until settlement occurs. At December 31, 2019 and 2018, the Company had regulatory and environmental liabilities of $10 million and $26 million, respectively, which are included in other current liabilities on the accompanying consolidated balance sheets. During the years ended December 31, 2019, 2018 and 2017, the Company recognized regulatory and environmental charges of $13 million, $23 million and $9 million, respectively, which are included in oil and natural gas production expense in the accompanying consolidated statements of operations.

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Commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds. These contractual arrangements relate to purchase agreements the Company has entered into, which includes throughput volume delivery commitments, fixed and variable power commitments, water commitment agreements, sand commitment agreements and other commitments. The Company's drilling rig commitments are considered leases under ASU 2016-02 and are discussed in the "Leases" section below. The following table summarizes the Company's commitments at December 31, 2019:

(in millions)	Volume Delivery Commitments (b)	Power Commitments (a)	Other Commitments	Total
2020	$ 8	$ 14	$ 29	$ 51
2021	19	14	38	71
2022	19	14	5	38
2023	19	14	2	35
2024	19	14	2	35
Thereafter	54	44	5	103
Total	$ 138	$ 114	$ 81	$ 333

(a) Certain power commitments include a variable price component that is based on the last day settlement price of the NYMEX futures contract for the physical delivery period.

(b) Volume delivery commitments do not include the oil marketing contract discussed in the table below.

At December 31, 2019, the Company's delivery commitments covered the following gross volumes of oil and natural gas:

	Oil (in MMBbl) (a)	Natural Gas (in MMcf)
2020	43	371
2021	51	7,267
2022	53	16,425
2023	51	16,425
2024	47	16,470
Thereafter	114	32,850
Total	359	89,808

(a) Included in the table above is an oil marketing contract with a third-party purchaser that requires the Company to deliver fifty thousand barrels of oil per day.

Leases. The Company leases office space, office equipment, drilling rigs, field equipment and vehicles. Right-of-use assets and lease liabilities are initially recorded at commencement date based on the present value of lease payments over the lease term. Leased assets may be used in joint operations with other working interest owners. When the Company is the operator in a joint arrangement, the right-of-use assets and lease liabilities are determined on a gross basis. Certain leases contain variable costs above the minimum required payments and are not included in the right-of-use assets or lease liabilities. Options to extend or terminate a lease are included in the lease term when it is reasonably certain the Company will exercise that option. For operating leases, lease cost is recognized on a straight-line basis over the term of the lease. Leases with an initial term of 12 months or less are not recorded on the consolidated balance sheet. The Company elected a practical expedient to not separate non-lease components from lease components for the following asset types: office space, office equipment, drilling rigs, and field equipment. The Company did not elect this practical expedient for vehicle leases.

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The following table provides supplemental consolidated balance sheet information related to leases at December 31, 2019:

(in millions)	Classification	December 31, 2019
Assets		
Operating lease right-of-use assets	Other property and equipment, net	$ 15
Finance lease right-of-use assets	Other property and equipment, net	16
Total lease right-of-use assets (a)		$ 31
Liabilities		
Current:		
Operating	Other current liabilities	$ 8
Finance	Other current liabilities	7
Noncurrent:		
Operating	Asset retirement obligations and other long-term liabilities	9
Finance	Asset retirement obligations and other long-term liabilities	10
Total lease liabilities (a)		$ 34

(a) Total lease right-of-use assets and lease liabilities are gross amounts, and a portion of these costs will be reimbursed by other working interest owners.

As of December 31, 2019, the Company had additional operating leases that have not yet commenced. Future undiscounted lease payments of $15 million and estimated lease incentives of $5 million will be included in the determination of the right-of-use asset and lease liability upon lease commencement.

The following table provides the components of lease cost, excluding lease cost related to short-term leases, for the year ended December 31, 2019:

(in millions)	Classification	December 31, 2019
Operating lease cost	General and administrative	$ 7
Finance lease cost	Depreciation, depletion, and amortization (a)	8
Total lease cost		$ 15

(a) Interest on lease liabilities related to finance leases was immaterial during the year ended December 31, 2019.

The Company's short-term leases are primarily composed of drilling rigs and certain field equipment. During the year ended December 31, 2019, the Company's gross lease costs related to its short-term leases were $307 million, of which $207 million were capitalized as part of oil and natural gas properties. A portion of these costs was reimbursed to the Company by other working interest owners.

The following table summarizes supplemental cash flow information related to leases for the year ended December 31, 2019:

(in millions)	December 31, 2019
Cash paid for amounts included in measurement of lease liabilities:	
Operating cash flows from operating leases	$ 8
Financing cash flows from finance leases	$ 7
Right-of-use assets obtained in exchange for lease obligations:	
Operating leases	$ 3
Finance leases	$ 9

The following table provides lease terms and discount rates related to leases at December 31, 2019:

	December 31, 2019
Weighted average remaining lease term (years):	
Operating leases	3.2
Finance leases	2.8
Weighted average discount rate (a):	
Operating leases	4.7%
Finance leases	4.2%

(a) The Company uses the rate implicit in the contract, if readily determinable, or its incremental borrowing rate at the commencement date as the discount rate in determining the present value of the lease payments.

The following table provides maturities of lease liabilities at December 31, 2019:

(in millions)	Operating Leases	Finance Leases
2020	$ 8	$ 7
2021	7	6
2022	2	4
2023	—	1
2024	—	—
Thereafter	2	—
Total lease payments	19	18
Less: interest	(2)	(1)
Present value of lease liabilities	$ 17	$ 17

As discussed in Note 2, the Company elected a transition method to recognize the effects of applying the new standard as a cumulative-effect adjustment to the opening balance of retained earnings. Per ASU 2016-02, an entity electing this transition method should provide the required disclosures under Topic 840 for all periods that continue to be in accordance with Topic 840. As such, the Company included the future minimum lease commitments table below as of December 31, 2018. In addition, lease payments associated with these operating leases were $13 million and $10 million for the years ended December 31, 2018 and 2017, respectively.

Future minimum lease commitments under non-cancellable leases at December 31, 2018 were as follows:

(in millions)	
2019	$ 14
2020	12
2021	10
2022	3
2023	—
Thereafter	1
Total	$ 40

Note 12. ***Income taxes***

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. The Company's objectives of accounting for income taxes are to recognize (i) the amount of taxes payable or refundable for the current year and (ii) the deferred tax liabilities and assets for the future tax consequences of events that have been recognized in its financial statements or tax returns. The Company and its subsidiaries file a federal corporate income tax return on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities.

The Company's income tax expense (benefit) attributable to income (loss) from operations consisted of the following for the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Current:			
U.S. federal	$ —	$ —	$ (6)
U.S. state	—	(2)	2
Total current income tax benefit	—	(2)	(4)
Deferred:			
U.S. federal	(112)	547	(94)
U.S. state	(42)	58	23
Total deferred income tax expense (benefit)	(154)	605	(71)
Total income tax expense (benefit)	$ (154)	$ 603	$ (75)

The reconciliation between the income tax expense (benefit) computed by multiplying pre-tax income (loss) by the U.S. federal statutory rate and the reported amounts of income tax expense (benefit) is as follows:

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Income (loss) at U.S. federal statutory rate	$ (180)	$ 607	$ 308
Non-deductible goodwill	64	—	—
Enactment date and measurement period adjustments from the TCJA	—	(7)	(398)
State income taxes and enacted tax law changes, net of federal tax effect	(13)	52	17
Change in estimated effective statutory state income tax rate	(21)	(8)	—
Excess tax benefit due to stock-based compensation	—	(12)	(6)
Research and development credits, net of unrecognized tax benefits	(11)	(41)	—
Other	7	12	4
Income tax expense (benefit)	$ (154)	$ 603	$ (75)
Effective tax rate	18%	21%	(9)%

On December 22, 2017, the President signed into law the TCJA, which enacted significant changes to federal income tax laws, including a decrease in the federal corporate income tax rate from 35 percent to 21 percent, which was effective January 1, 2018. In accordance with SAB 118, the Company recorded, based on reasonable estimates, a $398 million decrease to its income tax provision at December 31, 2017. This provisional amount related to the re-measurement of certain deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future. At December 31, 2018, the Company completed its accounting for all of the enactment-date tax effects of the TCJA and recognized an adjustment of $7 million, which is included as a component of income tax expense.

The Company monitors changes in enacted tax rates for the jurisdictions in which it operates. During 2019, the state of New Mexico enacted a tax law which, among other changes, amended the apportioned net operating loss ("NOL") carryforwards for corporations. As a result of this law change, the Company recorded a deferred state tax benefit of $6 million for the year ended December 31, 2019. The Company monitors its state tax apportionment footprint and makes updates for changes in its projected activity, including changes in budgets and drilling plans, and changes as a result of acquisitions or divestitures, including the New Mexico Shelf divestiture in 2019. Based upon the Company's projected future activity for the states in which it conducts business, the timing for when it anticipates its deferred tax items to become taxable, the enacted tax rates at such time deferred items become taxable and the New Mexico tax law change discussed above, the Company revised its estimated state tax rate for the year ended December 31, 2019. As a result, the Company recorded an income tax benefit of $21 million in its income tax provision for the year ended December 31, 2019. The Company revised its estimated state tax rate during 2018, primarily due to the impact of the RSP Acquisition. As a result, the Company recorded an income tax benefit of $8 million, net of federal tax benefit, in its income tax provision for the year ended December 31, 2018. The Company did not revise its estimated state rate and, as such, did not record an additional deferred state tax benefit for the year ended December 31, 2017.

The Company recorded an income tax benefit of $12 million and $6 million for the years ended December 31, 2018 and 2017, respectively, related to an excess tax benefit on stock-based awards, which are recorded in the income tax provision pursuant to ASU No. 2016-09, "Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-based Payment Accounting," ("ASU 2016-09") adopted on January 1, 2017.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows:

	December 31,	
(in millions)	**2019**	**2018**
Deferred tax assets:		
Stock-based compensation	$ 24	$ 26
Derivative instruments	23	—
Asset retirement obligation	31	41
Net operating losses and other carryforwards	590	525
Research and development and other credits	73	61
Other	22	17
Total deferred tax assets	763	670
Less: Valuation allowance	(4)	(3)
Net deferred tax assets	759	667
Deferred tax liabilities:		
Oil and natural gas properties, principally due to differences in basis and depreciation and the deduction of intangible drilling costs for tax purposes	(2,318)	(2,270)
Equity method investments	(83)	—
Intangible assets - operating rights	(4)	(4)
Derivative instruments	—	(158)
Other	(8)	(43)
Total deferred tax liabilities	(2,413)	(2,475)
Net deferred tax liabilities	$ (1,654)	$ (1,808)

The Company had net deferred tax liabilities of approximately $1.7 billion and $1.8 billion as of December 31, 2019 and 2018, respectively. On July 19, 2018, the Company completed the RSP Acquisition. For federal income tax purposes, the transaction qualified as a tax-free merger whereby the Company acquired carryover tax basis in RSP's assets and liabilities. As of December 31, 2018, the Company recorded an opening balance sheet deferred tax liability of $515 million based on its assessment of the carryover tax basis, and includes a deferred tax asset related to tax attributes acquired from RSP. The acquired income tax attributes primarily consist of NOLs and research and development credits that are subject to an annual limitation under Internal Revenue Code Section 382. The Company expects that these tax attributes will be fully utilized prior to expiration.

Pursuant to management's assessment, the Company does not believe a cumulative ownership change had occurred as of December 31, 2019. As such, Section 382 of the Internal Revenue Code of 1986, as amended, is not expected to limit the Company's ability to utilize its NOL carryforward.

At December 31, 2019, the Company had approximately $2.6 billion of federal NOLs, net of reduction for unrecognized tax benefits. At December 31, 2019, the Company had approximately $1.5 billion of NOLs that will begin to expire in the tax year 2034 but are allowable as a deduction against 100 percent of future taxable income since they were generated prior to the effective date of the limitations imposed by the TCJA. Additionally, the Company has estimated an apportioned New Mexico NOL of $749 million that will begin to expire in 2036.

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Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company's NOLs and other deferred tax attributes will be utilized prior to their expiration. Management considered all factors, including the expected reversal of deferred tax liabilities (including the impact of available carryforward periods), historical operating income tax planning strategies and projected future taxable income. Based on the results of the assessment, a valuation allowance of $4 million and $3 million was recorded at December 31, 2019 and 2018, respectively, related to charitable contribution carryforwards not anticipated to be utilized prior to expiration. Management determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

The following table sets forth changes in the Company's unrecognized tax benefits:

(in millions)	December 31, 2019	December 31, 2018
Balance at beginning of year	$ 72	$ —
Additions for tax positions acquired	—	26
Additions for prior period tax positions	—	20
Reductions for prior period tax positions	(1)	—
Additions for current tax period positions	11	26
Balance at end of year	$ 82	$ 72
Total that, if recognized, would impact the effective income tax rate	$ 74	$ 63

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities based upon the technical merits of the position. The Company had unrecognized tax benefits primarily related to research and development credits. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period recognized. The timing as to when the Company will substantially resolve the uncertainties associated with the unrecognized tax benefit is uncertain. The Company does not expect that a change in the unrecognized tax benefit within the next 12 months would have a material impact to the financial statements.

The Company has not recognized any interest or penalties relating to unrecognized tax benefits in its consolidated financial statements. Any interest or penalties would be recognized as a component of income tax expense. In the Company's major tax jurisdictions, the earliest year open to examination is 2014.

Note 13. *Major customers and derivative counterparties*

Sales to major customers. The Company's share of oil and natural gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have a material adverse effect on the ability of the Company to sell its oil and natural gas production.

The following purchasers individually accounted for 10 percent or more of the Company's consolidated oil and natural gas revenues during the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
	2019	2018	2017
Plains Marketing and Transportation, Inc.	17%	18%	21%
Enterprise Crude Oil LLC	10%	(a)	(a)
Holly Frontier Refining and Marketing, LLC	(a)	(a)	10%

(a) Purchaser did not account for 10% or more of total revenue for the period.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Company believes that all of its derivative counterparties are currently acceptable credit risks. The Company is not required to provide credit support or collateral to any counterparties under its derivative contracts, nor are they required to provide credit support to the Company.

Note 14. *Related party transactions*

The Company paid royalties on certain properties to a partnership in which a director of the Company is the general partner and owns a 3.5 percent partnership interest. These payments were reported in the Company's consolidated statements of operations and totaled $7 million, $8 million and $7 million for the years ended December 31, 2019, 2018 and 2017, respectively.

At December 31, 2019, the Company had ownership interests in entities that operate and manage various infrastructure assets and accounts for these investments using the equity method. The Company made payments of $40 million to these entities and received payments of $3 million from these entities during the year ended December 31, 2019.

Note 15. *Earnings per share*

The Company uses the two-class method of calculating earnings per share because certain of the Company's unvested share-based awards qualify as participating securities.

The Company's basic earnings (loss) per share attributable to common stockholders is computed as (i) net income (loss) as reported, (ii) less participating basic earnings (iii) divided by weighted average basic common shares outstanding. The Company's diluted earnings (loss) per share attributable to common stockholders is computed as (i) basic earnings (loss) attributable to common stockholders, (ii) plus reallocation of participating earnings (iii) divided by weighted average diluted common shares outstanding.

The following table reconciles the Company's earnings from operations and earnings attributable to common stockholders to the basic and diluted earnings used to determine the Company's earnings per share amounts for the years ended December 31, 2019, 2018 and 2017, respectively, under the two-class method:

	Years Ended December 31,		
(in millions, except per share amounts)	**2019**	**2018**	**2017**
Net income (loss) as reported	$ (705)	$ 2,286	$ 956
Participating basic earnings (a)	(1)	(17)	(7)
Basic earnings attributable to common stockholders	(706)	2,269	949
Reallocation of participating earnings	—	—	—
Diluted earnings attributable to common stockholders	$ (706)	$ 2,269	$ 949

(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends or distributions with the common equity holders of the Company. Participating earnings represent the distributed and undistributed earnings of the Company attributable to the participating securities. Unvested restricted stock awards do not participate in undistributed net losses as they are not contractually obligated to do so.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
(in thousands)	**2019**	**2018**	**2017**
Weighted average common shares outstanding:			
Basic	198,984	170,925	147,320
Dilutive common stock options	—	—	3
Dilutive performance units	—	324	633
Diluted	198,984	171,249	147,956

The following table is a summary of the performance units, which were not included in the computation of diluted net income per share, as inclusion of these items would be antidilutive:

	Years Ended December 31,		
(in thousands)	**2019**	**2018**	**2017**
Number of antidilutive common shares:			
Antidilutive performance units	431	108	81

Concho Resources Inc.
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Note 16. ***Stockholders' equity***

Share repurchase program. In September 2019, the Company announced that its board of directors authorized the initiation of a share repurchase program for up to $1.5 billion of the Company's common stock. A portion of the proceeds from the New Mexico Shelf divestiture was used to initiate the share repurchase program. As of December 31, 2019, the Company had repurchased and retired 3,300,370 shares under the program at an aggregate cost of $250 million. The Company's share repurchase program may be modified, suspended or terminated at any time by the Company's board of directors. The Company is not obligated to acquire any specific number of shares.

Common stock dividends. The Company paid dividends of $100 million, or $0.50 per share, during the year ended December 31, 2019. Any payment of future dividends will be at the discretion of the Company's board of directors. Covenants contained in the Company's agreement governing its Credit Facility and the indentures governing the Company's senior notes could limit the payment of dividends.

Note 17. ***Other current liabilities***

The following table provides the components of the Company's other current liabilities at December 31, 2019 and 2018:

	December 31,	
(in millions)	**2019**	**2018**
Other current liabilities:		
Accrued production costs	$ 175	$ 135
Payroll related matters	37	49
Accrued interest	60	70
Settlements due on derivatives	38	—
Asset retirement obligations	9	11
Other	44	55
Other current liabilities	$ 363	$ 320

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Note 18. ***Subsidiary guarantors***

At December 31, 2019, certain of the Company’s 100 percent owned subsidiaries have fully and unconditionally guaranteed the Company’s senior notes. The indentures governing the Company’s senior notes provide that the guarantees of its subsidiary guarantors will be released in certain customary circumstances including (i) in connection with any sale, exchange or other disposition, whether by merger, consolidation or otherwise, of the capital stock of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, such that, after giving effect to such transaction, such guarantor would no longer constitute a subsidiary of the Company, (ii) in connection with any sale, exchange or other disposition (other than a lease) of all or substantially all of the assets of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, (iii) upon the merger of a guarantor into the Company or any other guarantor or the liquidation or dissolution of a guarantor, (iv) if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture, (v) upon legal defeasance or satisfaction and discharge of the indenture and (vi) upon written notice of such release or discharge by the Company to the trustee following the release or discharge of all guarantees by such guarantor of any indebtedness that resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee.

See Note 10 for a summary of the Company’s senior notes. In accordance with practices accepted by the SEC, the Company has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. In addition, certain of the Company’s subsidiaries do not guarantee the Company’s senior notes and are included in the Company’s consolidated financial statements. These entities are 100 percent owned subsidiaries and are referred to as “Subsidiary Non-Guarantors” in the tables below. An additional entity did not guarantee the Company’s senior notes at December 31, 2017. This entity was a VIE that was formed to effectuate a tax-free exchange of assets. During 2018, the Reverse Exchange 1031 was completed and all assets and liabilities attributable to the VIE were conveyed to the Company. This entity did not guarantee the Company’s senior notes until the conveyance was completed. See Note 5 for additional information regarding the completion of the Reverse 1031 Exchange.

The following condensed consolidating balance sheets at December 31, 2019 and 2018, condensed consolidating statements of operations and condensed consolidating statements of cash flows for the years ended December 31, 2019, 2018 and 2017, present financial information for Concho Resources Inc. as the parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), financial information for the subsidiary non-guarantors on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc., as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors and subsidiary non-guarantors are not restricted from making distributions to the Company.

Concho Resources Inc.
Notes to Consolidated Financial Statements
December 31, 2019, 2018 and 2017

Condensed Consolidating Balance Sheet
December 31, 2019

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
ASSETS					
Accounts receivable - related parties	$ 17,429	$ —	$ —	$ (17,429)	$ —
Other current assets	10	1,045	—	—	1,055
Oil and natural gas properties, net	—	20,874	16	—	20,890
Property and equipment, net	—	437	—	—	437
Investment in subsidiaries	5,635	—	—	(5,635)	—
Goodwill	—	1,917	—	—	1,917
Other long-term assets	22	411	—	—	433
Total assets	$ 23,096	$ 24,684	$ 16	$ (23,064)	$ 24,732
LIABILITIES AND EQUITY					
Accounts payable - related parties	$ —	$ 17,413	$ 16	$ (17,429)	$ —
Other current liabilities	211	971	—	—	1,182
Long-term debt	3,955	—	—	—	3,955
Other long-term liabilities	1,148	665	—	—	1,813
Equity	17,782	5,635	—	(5,635)	17,782
Total liabilities and equity	$ 23,096	$ 24,684	$ 16	$ (23,064)	$ 24,732

Condensed Consolidating Balance Sheet
December 31, 2018

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
ASSETS					
Accounts receivable - related parties	$ 18,155	$ —	$ —	$ (18,155)	$ —
Other current assets	534	875	—	—	1,409
Oil and natural gas properties, net	—	21,988	17	—	22,005
Property and equipment, net	—	308	—	—	308
Investment in subsidiaries	5,411	—	—	(5,411)	—
Goodwill	—	2,224	—	—	2,224
Other long-term assets	224	124	—	—	348
Total assets	$ 24,324	$ 25,519	$ 17	$ (23,566)	$ 26,294
LIABILITIES AND EQUITY					
Accounts payable - related parties	$ —	$ 18,138	$ 17	$ (18,155)	$ —
Other current liabilities	70	1,286	—	—	1,356
Long-term debt	4,194	—	—	—	4,194
Other long-term liabilities	1,292	684	—	—	1,976
Equity	18,768	5,411	—	(5,411)	18,768
Total liabilities and equity	$ 24,324	$ 25,519	$ 17	$ (23,566)	$ 26,294

Concho Resources Inc.
Notes to Consolidated Financial Statements
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Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2019

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Total operating revenues	$ —	$ 4,591	$ 1	$ —	$ 4,592
Total operating costs and expenses	(898)	(4,681)	—	—	(5,579)
Income (loss) from operations	(898)	(90)	1	—	(987)
Interest expense	(185)	—	—	—	(185)
Other, net	224	313	—	(224)	313
Income (loss) before income taxes	(859)	223	1	(224)	(859)
Income tax benefit	154	—	—	—	154
Net income (loss)	$ (705)	$ 223	$ 1	$ (224)	$ (705)

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2018

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Total operating revenues	$ —	$ 4,146	$ 5	$ —	$ 4,151
Total operating costs and expenses	829	(2,047)	(3)	—	(1,221)
Income from operations	829	2,099	2	—	2,930
Interest expense	(149)	—	—	—	(149)
Other, net	2,209	108	—	(2,209)	108
Income before income taxes	2,889	2,207	2	(2,209)	2,889
Income tax expense	(603)	—	—	—	(603)
Net income	$ 2,286	$ 2,207	$ 2	$ (2,209)	$ 2,286

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Total operating revenues	$ —	$ 2,566	$ 20	$ —	$ 2,586
Total operating costs and expenses	(129)	(1,369)	(17)	—	(1,515)
Income (loss) from operations	(129)	1,197	3	—	1,071
Interest expense	(145)	(1)	—	—	(146)
Loss on extinguishment of debt	(66)	—	—	—	(66)
Other, net	1,221	22	—	(1,221)	22
Income before income taxes	881	1,218	3	(1,221)	881
Income tax benefit	75	—	—	—	75
Net income	$ 956	$ 1,218	$ 3	$ (1,221)	$ 956

Concho Resources Inc.
Notes to Consolidated Financial Statements
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Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2019

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 607	$ 2,229	$ —	$ —	$ 2,836
Net cash flows used in investing activities	—	(1,993)	—	—	(1,993)
Net cash flows used in financing activities	(607)	(166)	—	—	(773)
Net change in cash and cash equivalents	—	70	—	—	70
Cash and cash equivalents at beginning of period	—	—	—	—	—
Cash and cash equivalents at end of period	$ —	$ 70	$ —	$ —	$ 70

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2018

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 338	$ 2,220	$ —	$ —	$ 2,558
Net cash flows used in investing activities	—	(2,216)	—	—	(2,216)
Net cash flows used in financing activities	(338)	(4)	—	—	(342)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	—	—	—	—
Cash and cash equivalents at end of period	$ —	$ —	$ —	$ —	$ —

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 145	$ 1,549	$ 1	$ —	$ 1,695
Net cash flows used in investing activities	—	(1,105)	(614)	—	(1,719)
Net cash flows provided by (used in) financing activities	(145)	(497)	613	—	(29)
Net change in cash and cash equivalents	—	(53)	—	—	(53)
Cash and cash equivalents at beginning of period	—	53	—	—	53
Cash and cash equivalents at end of period	$ —	$ —	$ —	$ —	$ —

Note 19. ***Subsequent events***

Dividends. On February 18, 2020, the Company's board of directors declared a cash dividend of $0.20 per share for the first quarter of 2020. The total cash dividend, including the cash dividend on unvested restricted stock awards, of $39 million is expected to be paid on March 27, 2020.

New commodity derivative contracts. After December 31, 2019, the Company entered into the following derivative contracts to hedge additional amounts of estimated future production:

	2020						
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	2021	2022
Oil Price Swaps – WTI: (a)							
Volume (MBbl)	—	—	—	—	—	365	—
Price per Bbl	$ —	$ —	$ —	$ —	$ —	$ 55.24	$ —
Oil Basis Swaps: (b)							
Volume (MBbl)	—	1,092	309	61	1,462	1,460	—
Price per Bbl	$ —	$ 1.11	$ 1.05	$ 1.00	$ 1.09	$ 1.23	$ —
Natural Gas Price Swaps - Henry Hub: (c)							
Volume (BBtu)	—	—	—	—	—	29,200	36,500
Price per MMBtu	$ —	$ —	$ —	$ —	$ —	$ 2.34	$ 2.38
Natural Gas Basis Swaps - Henry Hub/El Paso Permian: (d)							
Volume (BBtu)	—	—	—	—	—	14,600	29,200
Price per MMBtu	$ —	$ —	$ —	$ —	$ —	$ (1.08)	$ (0.72)
Natural Gas Basis Swaps - Henry Hub/WAHA: (e)							
Volume (BBtu)	—	—	—	—	—	7,300	7,300
Price per MMBtu	$ —	$ —	$ —	$ —	$ —	$ (1.30)	$ (0.85)

(a) The oil derivative contracts are settled based on the NYMEX – WTI calendar-month average futures price.

(b) The basis differential price is between Midland – WTI and Cushing – WTI. These contracts are settled on a calendar-month basis.

(c) The natural gas derivative contracts are settled based on the NYMEX – Henry Hub last trading day futures price.

(d) The basis differential price is between NYMEX – Henry Hub and El Paso Permian.

(e) The basis differential price is between NYMEX – Henry Hub and WAHA.

Capitalized costs

	December 31,	
(in millions)	**2019**	**2018**
Oil and natural gas properties:		
Proved	$ 22,915	$ 24,992
Unproved	5,870	6,714
Less: accumulated depletion	(7,895)	(9,701)
Net capitalized costs for oil and natural gas properties	$ 20,890	$ 22,005

Costs incurred for oil and natural gas producing activities

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Property acquisition costs:			
Proved	$ 8	$ 4,136	$ 303
Unproved	50	3,617	905
Exploration	1,637	1,588	1,021
Development	1,358	1,050	653
Total costs incurred for oil and natural gas properties	$ 3,053	$ 10,391	$ 2,882

Reserve Quantity Information

The following information represents estimates of the Company's proved reserves. The pricing that was used for estimates of the Company's reserves as of December 31, 2019 was based on the SEC pricing of $52.19 per Bbl West Texas Intermediate posted oil price and $2.58 per MMBtu Henry Hub spot natural gas price.

Subject to limited exceptions, proved undeveloped reserves may only be recognized if they relate to wells scheduled to be drilled within five years of the date of their initial recognition. This rule limited, and may continue to limit, the Company's potential to record additional proved undeveloped reserves. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. All of the Company's recorded proved undeveloped reserves are scheduled to be drilled within five years of the date of their initial recognition.

The Company's proved oil and natural gas reserves are all located in the United States, primarily in the Permian Basin of West Texas and Southeast New Mexico. All of the estimates of the proved reserves at December 31, 2019, 2018 and 2017 are based on reports prepared by Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

The following table summarizes the prices utilized in the reserve estimates for 2019, 2018 and 2017. Commodity prices utilized for the reserve estimates prior to adjustments for location, grade and quality are as follows:

	December 31,		
	2019	2018	2017
Prices utilized in the reserve estimates before adjustments:			
Oil per Bbl	$ 52.19	$ 62.04	$ 47.79
Natural gas per MMBtu	$ 2.58	$ 3.10	$ 2.98

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

Concho Resources Inc.
Unaudited Supplementary Data
December 31, 2019, 2018 and 2017

The following table provides a rollforward of the total proved reserves for the years ended December 31, 2019, 2018 and 2017, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year.

	2019			2018			2017		
	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)
Total Proved Reserves:									
Balance, January 1	750	2,624	1,187	500	2,043	840	428	1,752	720
Purchases of minerals-in-place	6	19	9	233	449	308	22	72	34
Sales of minerals-in-place	(57)	(288)	(105)	(8)	(54)	(17)	(2)	(9)	(4)
Extensions and discoveries	121	331	177	151	452	226	115	351	174
Revisions of previous estimates	(125)	(121)	(145)	(65)	(58)	(74)	(20)	38	(14)
Production	(76)	(267)	(121)	(61)	(208)	(96)	(43)	(161)	(70)
Balance, December 31	619	2,298	1,002	750	2,624	1,187	500	2,043	840
Proved Developed Reserves:									
January 1	500	1,941	824	336	1,512	588	267	1,190	466
December 31	442	1,818	745	500	1,941	824	336	1,512	588
Proved Undeveloped Reserves:									
January 1	250	683	363	164	531	252	161	561	254
December 31	177	480	257	250	683	363	164	531	252

For the year ended December 31, 2019:

Extensions and discoveries. Extensions and discoveries of approximately 177 MMBoe were primarily the result of the Company's horizontal drilling programs in its operating areas. Proved developed reserves increased approximately 106 MMBoe due to the Company's drilling activity in 2019, and based upon this activity, the Company added approximately 71 MMBoe of new proved undeveloped reserves.

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place were primarily the result of certain acquisitions and nonmonetary transactions during 2019. The Company's sales of 105 MMBoe of minerals-in-place were the result of various divestitures and nonmonetary transactions during 2019, primarily the New Mexico Shelf divestiture. See Note 5 for additional information.

Revisions of previous estimates. Revisions of previous estimates were composed of (i) 28 MMBoe of negative revisions primarily due to the reclassification of proved undeveloped reserves to unproved as they were no longer expected to be developed within five years of the date of their initial recognition, (ii) 82 MMBoe of net negative performance and other revisions and (iii) 35 MMBoe of negative price revisions. The Company's proved reserves at December 31, 2019 were determined using the SEC prices of $52.19 per Bbl of oil for WTI and $2.58 per MMBtu of natural gas for Henry Hub spot, as compared to corresponding prices of $62.04 per Bbl of oil and $3.10 per MMBtu of natural gas at December 31, 2018. Negative performance revisions were primarily the result of the Company's recent capital programs that included projects testing tighter well spacing. The Company has modified its development approach to prioritize wider spacing between wells in order to maximize well performance and program economics.

For the year ended December 31, 2018:

Extensions and discoveries. Extensions and discoveries of approximately 226 MMBoe were primarily the result of the Company's horizontal drilling programs in the Company's operating areas. Proved developed reserves increased approximately 87 MMBoe due to the Company's drilling activity in 2018. Based upon this activity, approximately 139 MMBoe of new proved undeveloped locations were added.

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place were primarily the result of the RSP Acquisition in July 2018 which added approximately 275 MMBoe. The remainder of the purchases of minerals-in-place was primarily the result of certain acquisitions and nonmonetary transactions during 2018, which added approximately 25 MMBoe in the Midland

Basin and 8 MMBoe in the Delaware Basin. The Company's sales of minerals-in-place were primarily the result of various divestitures and nonmonetary transactions during 2018.

Revisions of previous estimates. Revisions of previous estimates were primarily composed of (i) 77 MMBoe of negative revisions primarily due to proved undeveloped reserves reclassified to unproved, (ii) 15 MMBoe of net negative performance and other revisions and (iii) 18 MMBoe of positive price revisions. As the Company transitioned its development program to large-scale projects and evaluated and analyzed its producing oil and natural gas properties and drilling prospects, certain properties were no longer expected to be developed within five years of the date of their initial recognition and were removed from the Company's current drilling plans. This included certain properties that were identified to have a lower liquids content and certain non-operated properties that the Company reclassified due to the uncertainty regarding the timing of development. Net negative performance and other revisions primarily related to 27 MMBoe of downward revisions to certain proved developed producing properties in the Yeso field, partially offset by other positive performance revisions. Positive price revisions were the result of an increase in the oil and natural gas prices utilized in the Company's reserve estimates at December 31, 2018 as compared to December 31, 2017.

For the year ended December 31, 2017:

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place were composed of approximately 11 MMBoe from the July 2017 Midland Basin acquisition, 8 MMBoe from the January 2017 Delaware Basin acquisition and 15 MMBoe from various other acquisitions throughout the year. The Company's sales of minerals-in-place are composed of approximately 4 MMBoe from various divestitures throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 174 MMBoe were primarily the result of the Company's extension and infill horizontal drilling programs in its operating areas. Proved developed reserves increased approximately 82 MMBoe due to the Company's exploratory drilling activity in 2017. Based upon this activity, approximately 92 MMBoe of new proved undeveloped locations were added.

Revisions of previous estimates. Revisions of previous estimates were composed of (i) 61 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition as required by SEC rules due to a shift in the Company's capital program to generally focus more on large-scale development projects in certain areas, (ii) 29 MMBoe of positive price revisions and (iii) 18 MMBoe of positive technical and performance revisions.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

The following table provides the standardized measure of discounted future net cash flows at December 31, 2019, 2018 and 2017:

	December 31,		
(in millions)	**2019**	**2018**	**2017**
Oil and gas producing activities:			
Future cash inflows	$ 36,001	$ 56,621	$ 29,761
Future production costs	(13,519)	(16,511)	(9,612)
Future development and abandonment costs (a)	(2,672)	(3,731)	(2,636)
Future income tax expense	(2,570)	(5,694)	(2,565)
Future net cash flows	17,240	30,685	14,948
10% annual discount factor	(7,657)	(15,130)	(7,470)
Standardized measure of discounted future net cash flows	$ 9,583	$ 15,555	$ 7,478

(a) Includes $249 million, $329 million and $256 million of undiscounted asset retirement cash outflow estimated at December 31, 2019, 2018 and 2017, respectively, using current estimates of future abandonment costs less salvage values.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table provides a rollforward of the standardized measure of discounted future net cash flows for the years ended December 31, 2019, 2018 and 2017:

	Year Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Oil and natural gas producing activities:			
Purchases of minerals-in-place	$ 103	$ 4,555	$ 304
Sales of minerals-in-place	(899)	(176)	(20)
Extensions and discoveries	2,241	3,562	2,014
Development costs incurred during the period	1,086	783	619
Net changes in prices and production costs	(6,789)	2,926	1,830
Oil and natural gas sales, net of production costs	(3,412)	(3,201)	(1,979)
Changes in future development costs	203	304	84
Revisions of previous quantity estimates	(1,606)	(1,113)	(154)
Accretion of discount	1,635	1,001	470
Changes in production rates, timing and other	74	827	470
Change in present value of future net revenues	(7,364)	9,468	3,638
Net change in present value of future income tax benefit	1,392	(1,391)	(350)
	(5,972)	8,077	3,288
Balance, beginning of year	15,555	7,478	4,190
Balance, end of year	$ 9,583	$ 15,555	$ 7,478

Concho Resources Inc.
Unaudited Supplementary Data
December 31, 2019, 2018 and 2017

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2019 and 2018:

(in millions, except per share data)	Quarter First	Quarter Second	Quarter Third	Quarter Fourth
Year ended December 31, 2019:				
Total operating revenues	$ 1,104	$ 1,127	$ 1,115	$ 1,246
Operating costs and expenses (excluding gains (losses) on derivatives and gains on disposition of assets, net) (a)	(892)	(1,748)	(993)	(1,221)
Gains (losses) on derivatives	(1,059)	217	397	(450)
Gains (losses) on disposition of assets, net	1	(1)	303	(133)
Income (loss) from operations	$ (846)	$ (405)	$ 822	$ (558)
Income tax (expense) benefit	$ 194	$ 53	$ (222)	$ 129
Net income (loss)	$ (695)	$ (97)	$ 558	$ (471)
Earnings per common share - Basic	$ (3.49)	$ (0.48)	$ 2.78	$ (2.38)
Earnings per common share - Diluted	$ (3.49)	$ (0.48)	$ 2.78	$ (2.38)
Year ended December 31, 2018:				
Total operating revenues	$ 947	$ 945	$ 1,192	$ 1,067
Operating costs and expenses (excluding gains (losses) on derivatives and gains on disposition of assets, net)	(620)	(610)	(787)	(836)
Gains (losses) on derivatives	(35)	(133)	(625)	1,625
Gains (losses) on disposition of assets, net	723	1	(5)	81
Income (loss) from operations	$ 1,015	$ 203	$ (225)	$ 1,937
Income tax (expense) benefit	$ (254)	$ (40)	$ 69	$ (378)
Net income (loss)	$ 835	$ 137	$ (199)	$ 1,513
Earnings per common share - Basic	$ 5.60	$ 0.92	$ (1.05)	$ 7.56
Earnings per common share - Diluted	$ 5.58	$ 0.92	$ (1.05)	$ 7.55

(a) Third and fourth quarters of 2019 include $81 million and $201 million of goodwill impairment charges, respectively. Refer to Note 2 for additional information related to impairments of goodwill. In addition, second and third quarters of 2019 include $868 million and $20 million of impairments of long-lived assets, respectively. Refer to Note 8 for additional information related to impairments of long-lived assets.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2019 at the reasonable assurance level.

Management's Report on Internal Control over Financial Reporting. The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements in a timely manner. 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.

As of December 31, 2019, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria established in "Internal Control - Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company maintained effective internal control over financial reporting at December 31, 2019.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this annual report on Form 10-K, has issued its report on the effectiveness of the Company's internal control over financial reporting at December 31, 2019. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2019, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Concho Resources Inc.

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2019, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). 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 the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements of the Company as of and for the year ended December 31, 2019, and our report dated February 19, 2020 expressed an unqualified opinion on those financial statements.

Basis for opinion
The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

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

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 19, 2020

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2019.

Code of Ethics. Our board of directors has adopted a financial code of ethics applicable to our Chief Executive Officer, President, Chief Financial Officer, Chief Accounting Officer and other senior financial officers, and a code of business conduct and ethics applicable to our directors, officers and employees, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE (the "Codes"). The Codes can be found on our website located at *www.concho.com*. We intend to disclose future amendments to certain provisions of the Codes, and waivers of the Codes granted to executive officers and directors, on our website within four business days following the date of the amendment or waiver.

Item 11. Executive Compensation

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2019.

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

Equity compensation plans. At December 31, 2019, a total of 15,000,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. Included in column (1) are (i) unvested performance units at the maximum potential payout percentage and (ii) performance units relating to the performance period that ended on December 31, 2019 at the actual payout percentage of 38 percent. You can find descriptions of our stock incentive plan under Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Plan category	(1) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(2) Weighted average exercise price of outstanding options	(3) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (1))
Equity compensation plan approved by the security holders (a)	1,013,942	$ — (c)	4,961,182
Equity compensation plan not approved by the security holders (b)	—	$ —	—
Total	1,013,942		4,961,182

(a) 2019 Stock Incentive Plan. See Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(b) None.

(c) Performance unit awards do not have an exercise price and, therefore, have been excluded from the weighted average exercise price calculation in column (2).

The remaining information required by Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2019.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2019.

Item 14. Principal Accountant Fees and Services

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2019.

PART IV

Item 15.Exhibits, Financial Statement Schedules

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements are included in “Item 8. Financial Statements and Supplementary Data”:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2019 and 2018

Consolidated Statements of Operations for the Years Ended December 31, 2019, 2018 and 2017

Consolidated Statements of Stockholders’ Equity for the Years Ended December 31, 2019, 2018 and 2017

Consolidated Statements of Cash Flows for the Years Ended December 31, 2019, 2018 and 2017

Notes to Consolidated Financial Statements

Unaudited Supplementary Data

(b) Exhibits

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this report or they are inapplicable.

Exhibits

Exhibit Number	Description
2.1	Agreement and Plan of Merger among Concho Resources Inc., RSP Permian, Inc. and Green Merger Sub Inc., dated as of March 27, 2018 (filed as Exhibit 2.1 to the Company’s Current Report on Form 8-K on March 28, 2018, and incorporated herein by reference).
3.1	Restated Certificate of Incorporation of Concho Resources Inc. (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K on August 8, 2007, and incorporated herein by reference).
3.2	Fourth Amended and Restated Bylaws of Concho Resources Inc., as amended January 2, 2018 (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company’s Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).
4.2	Senior Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
4.3	Tenth Supplemental Indenture, dated December 28, 2016, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on December 28, 2016, and incorporated herein by reference).
4.4	Eleventh Supplemental Indenture, dated January 25, 2017, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.4 to the Company’s Registration Statement on Form S-3 on June 14, 2018, and incorporated herein by reference).
4.5	Twelfth Supplemental Indenture, dated September 26, 2017, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on September 26, 2017, and incorporated herein by reference).
4.6	Thirteenth Supplemental Indenture, dated September 26, 2017, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.2 to the Company’s Current Report on Form 8-K on September 26, 2017, and incorporated herein by reference).

4.7	Fourteenth Supplemental Indenture, dated July 2, 2018, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on July 2, 2018, and incorporated herein by reference).

4.8		Fifteenth Supplemental Indenture, dated July 2, 2018, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on July 2, 2018, and incorporated herein by reference).
4.9		Sixteenth Supplemental Indenture, dated August 14, 2018, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on August 15, 2018, and incorporated herein by reference).
4.10	(a)	Description of Securities
10.1	**	Form of Performance Unit Award Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2013, and incorporated herein by reference).
10.2	**	Form of Performance Unit Award Agreement, dated January 2, 2019 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).
10.3	**	Form of Performance Unit Award Agreement, dated January 2, 2020 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 6, 2020, and incorporated herein by reference).
10.4	**	Performance Unit Award Agreement, dated January 2, 2018, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).
10.5	**	Concho Resources Inc. 2019 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 17, 2019, and incorporated herein by reference).
10.6	**	Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.7	**	Form of Restricted Stock Agreement (for officers) (filed as Exhibit 10.1 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).
10.8	**	Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.9	**	Restricted Stock Agreement, dated January 2, 2018, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).
10.10	**	Form of Restricted Stock Agreement (for officers) (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).
10.11	**	Form of Succession Restricted Stock Agreement, dated January 2, 2019, between Concho Resources Inc. and each of Messrs. Harper and Giraud (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).
10.12	**	Form of Indemnification Agreement, dated January 2, 2019, between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).
10.13	**	Form of Succession 3-Year Performance Unit Award Agreement, dated January 2, 2019, between Concho Resources Inc. and each of Messrs. Harper and Giraud (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).
10.14	**	Form of Succession 5-Year Performance Unit Award Agreement, dated January 2, 2019, between Concho Resources Inc. and each of Messrs. Harper and Giraud (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).
10.15	**	Second Amended and Restated Credit Agreement, dated as of May 9, 2014, among Concho Resources Inc., the lenders party thereto, JPMorgan Chase Bank, N.A., as administrative agent, and the co-syndication agents and co-documentation agents named therein (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 12, 2014, and incorporated herein by reference).

10.16	**	First Amendment to Second Amended and Restated Credit Agreement, dated as of April 8, 2015, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 9, 2015, and incorporated herein by reference).
10.17	**	Second Amendment to Second Amended and Restated Credit Agreement, dated as of April 12, 2017, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on August 3, 2017, and incorporated herein by reference).
10.18		Third Amendment to Second Amended and Restated Credit Agreement, dated as of May 29, 2019, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on August 1, 2019, and incorporated herein by reference).

10.19	**	Executive Severance Plan, dated January 1, 2019, by and between Concho Resources Inc. and each of the officers thereof (filed as Exhibit 10.7 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).
21.1	(a)	Subsidiaries of Concho Resources Inc.
23.1	(a)	Consent of Grant Thornton LLP.
23.2	(a)	Consent of Netherland, Sewell & Associates, Inc.
23.3	(a)	Consent of Cawley, Gillespie & Associates, Inc.
31.1	(a)	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	(a)	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32.1	(b)	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2	(b)	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
99.1	(a)	Netherland, Sewell & Associates, Inc. Reserve Report, dated January 23, 2020.
99.2	(a)	Cawley, Gillespie & Associates, Inc. Reserve Report, dated January 27, 2020.
101.INS	(a)	XBRL Instance Document - The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	(a)	Inline XBRL Schema Document.
101.CAL	(a)	Inline XBRL Calculation Linkbase Document.
101.DEF	(a)	Inline XBRL Definition Linkbase Document.
101.LAB	(a)	Inline XBRL Labels Linkbase Document.
101.PRE	(a)	Inline XBRL Presentation Linkbase Document.
104	(a)	The cover page of Concho Resources Inc.'s Annual Report on Form 10-K for the year ended December 31, 2019, formatted in Inline XBRL and included within the Exhibit 101 attachments.

(a) Filed herewith.
(b) Furnished herewith.
** Management contract or compensatory plan or agreement.

Item 16. Form 10-K Summary

None.

SIGNATURES

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

CONCHO RESOURCES INC.

Date:	February 19, 2020	By	/s/ Timothy A. Leach
			Timothy A. Leach Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)

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

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 19, 2020
/s/ BRENDA R. SCHROER Brenda R. Schroer	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 19, 2020
/s/ JACOB P. GOBAR Jacob P. Gobar	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 19, 2020
/s/ STEVEN L. BEAL Steven L. Beal	Director	February 19, 2020
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 19, 2020
/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 19, 2020
/s/ STEVEN D. GRAY Steven D. Gray	Director	February 19, 2020
/s/ SUSAN J. HELMS Susan J. Helms	Director	February 19, 2020
/s/ GARY A. MERRIMAN Gary A. Merriman	Director	February 19, 2020
/s/ MARK B. PUCKETT Mark B. Puckett	Director	February 19, 2020
/s/ JOHN P. SURMA John P. Surma	Director	February 19, 2020
/s/ E. JOSEPH WRIGHT E. Joseph Wright	Director	February 19, 2020

EXHIBIT 4.10

CONCHO RESOURCES INC.
DESCRIPTION OF SECURITIES

DESCRIPTION OF CAPITAL STOCK

The common stock of Concho Resources Inc. (“we,” “us” and “our”) is listed on the New York Stock Exchange (the “NYSE”) under the symbol “CXO.” Our authorized capital stock consists of 300,000,000 shares of common stock, $0.001 par value per share, and 10,000,000 shares of preferred stock, $0.001 par value per share.

The following summary of our capital stock, Restated Certificate of Incorporation (the “Certificate of Incorporation”) and Fourth Amended and Restated Bylaws (the “Bylaws”) does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our Certificate of Incorporation and Bylaws.

Common Stock

Holders of our common stock are entitled to one vote for each share held on all matters submitted to a vote of stockholders and do not have cumulative voting rights. Accordingly, holders of a majority of the shares of our common stock entitled to vote in any election of directors may elect all of the directors standing for election.

Holders of our common stock are entitled to receive proportionately any dividends if and when such dividends are declared by our board of directors, subject to any preferential dividend rights of preferred stock that may be outstanding at the time such dividends are declared. Upon the liquidation, dissolution or winding up of our company, the holders of our common stock are entitled to receive ratably our net assets available after the payment of all debts and other liabilities and subject to the prior rights of any outstanding preferred stock. Holders of our common stock have no preemptive, subscription, redemption or conversion rights. The rights, preferences and privileges of holders of our common stock are subject to, and may be adversely affected by, the rights of the holders of shares of any series of preferred stock that we may designate and issue in the future.

The payment and amount of future dividend payments, if any, are at the discretion of our board of directors and subject to covenants contained in our credit facility and the indentures governing our unsecured senior notes, which could limit the payment of dividends. Such payments will depend on various factors, including actual results of operations, liquidity and financial condition, net cash provided by operating activities, restrictions imposed by applicable law, our taxable income, our operating expenses and other factors our board of directors deems relevant. We are under no obligation to make dividend payments on our common stock and may cease such payments at any time in the future.

There are no redemption or sinking fund provisions applicable to our common stock. All outstanding shares of our common stock are fully paid and non-assessable.

Preferred Stock

Under the terms of our Certificate of Incorporation, our board of directors is authorized to designate and issue shares of preferred stock in one or more series without further vote or action by our stockholders. Our board of directors has the discretion to determine the rights, preferences, privileges and restrictions, including voting rights, dividend rights, conversion rights, redemption privileges and liquidation preferences, of each series of preferred stock. It is not possible to state the actual effect of the issuance of any shares of preferred stock upon the rights of holders of the common stock until the board of directors determines the specific rights of the holders of the preferred stock. However, these effects might include:

- restricting dividends on the common stock;
- diluting the voting power of the common stock;
- impairing the liquidation rights of the common stock; and
- delaying or preventing a change in control of our company.

We currently have no shares of preferred stock outstanding, and we have no present plans to issue any shares of preferred stock.

Anti-Takeover Provisions of Our Certificate of Incorporation and Bylaws

Our Certificate of Incorporation and Bylaws contain several provisions that could delay or make more difficult the acquisition of us through a hostile tender offer, open market purchases, proxy contest, merger or other takeover attempt that a stockholder might consider in his or her best interest, including those attempts that might result in a premium over the market price of our common stock.

Written Consent of Stockholders

Our Certificate of Incorporation and Bylaws provide that any action required or permitted to be taken by our stockholders must be taken at a duly called meeting of stockholders and not by written consent.

Special Meetings of Stockholders

Subject to the rights of the holders of any series of preferred stock, our Bylaws provide that special meetings of the stockholders may only be called by the chairman of the board of directors or by the resolution of our board of directors approved by a majority of the total number of authorized directors. No business other than that stated in a notice may be transacted at any special meeting.

Advance Notice Procedure for Director Nominations and Stockholder Proposals

Our Bylaws provide that adequate notice must be given to nominate candidates for election as directors or to make proposals for consideration at annual meetings of our stockholders. For nominations or other business to be properly brought before an annual meeting by a stockholder, the stockholder must have delivered a written notice to the Secretary of our company at our principal executive offices not later than the close of business 90 calendar days nor earlier than 120 calendar days prior to the first anniversary of the preceding year’s annual meeting; provided, however, that in the event that the date of the annual meeting is more than 30 calendar days before or more than 30 calendar days after the first anniversary of the date of the preceding year’s annual meeting, or if no annual meeting was held in the preceding year, notice by the stockholder to be timely must be so delivered not later than the close of business on the later of the 90th calendar day prior to such annual meeting or the 10th calendar day following the calendar day on which public announcement, if any, of the date of such meeting is first made by us. In no event shall an adjournment or recess of an annual meeting, or a postponement of an annual meeting for which notice of the meeting has already been given to stockholders or a public announcement, if any, of the date of such meeting has already been made, commence a new time period (or extend any time period) for the giving of a stockholder's notice described in this paragraph.

Nominations of persons for election to our board of directors may be made at a special meeting of stockholders at which directors are to be elected pursuant to our notice of meeting (i) by or at the direction of our board of directors, or (ii) by any stockholder of our company who is a stockholder of record at the time of the giving of notice of the meeting, who is entitled to vote at the meeting and who complies with the notice procedures set forth in our Bylaws. In the event we call a special meeting of stockholders for the purpose of electing one or more directors to our board of directors, any stockholder may nominate a person or persons (as the case may be) for election to such position(s) if the stockholder provides written notice to the Secretary of our company at our principal executive offices not earlier than the 90th calendar day prior to such special meeting, nor later than the close of business on the later of the 70th calendar day prior to such special meeting or the 10th calendar day following the day on which public announcement, if any, is first made of the date of the special meeting and of the nominees proposed by our board of directors to be elected at such meeting. In no event shall an adjournment, recess or postponement of a special meeting commence a new time period (or extend any time period) for the giving of a stockholder's notice described in this paragraph.

These procedures may operate to limit the ability of stockholders to bring business before a stockholders meeting, including the nomination of directors and the consideration of any transaction that could result in a change in control and that may result in a premium to our stockholders.

Classified Board

Our Certificate of Incorporation divides our directors into three classes serving staggered three-year terms. As a result, stockholders will elect approximately one-third of the board of directors each year. This provision, when coupled with provisions of our Certificate of Incorporation authorizing only the board of directors to fill vacant or newly created directorships or increase the size of the board of directors and provisions providing that directors may only be removed for cause and then only by the holders of not less than 66 2/3% of the voting power of all outstanding voting stock, may deter a stockholder from gaining control of our board of directors by removing incumbent directors or increasing the number of directorships and simultaneously filling the vacancies or newly created directorships with its own nominees.

Authorized Capital Stock

Our Certificate of Incorporation contains provisions that the authorized but unissued shares of common stock and preferred stock are available for future issuance, subject to various limitations imposed by the NYSE. These additional shares may be utilized for a variety of corporate purposes, including public offerings to raise capital, corporate acquisitions and employee benefit plans.

Amendment of Bylaws

Under Delaware law, the power to adopt, amend or repeal bylaws is conferred upon the stockholders. A corporation may, however, in its certificate of incorporation also confer upon the board of directors the power to adopt, amend or repeal its bylaws. Our Certificate of Incorporation and Bylaws grant our board of directors the power to adopt, amend and repeal our Bylaws on the affirmative vote of a majority of the directors then in office. Our stockholders may adopt, amend or repeal our Bylaws but only at any regular or special meeting of stockholders by the holders of not less than 66 2/3% of the voting power of all outstanding voting stock.

Limitation of Liability of Directors

Our Certificate of Incorporation provides that no director shall be personally liable to us or our stockholders for monetary damages for breach of fiduciary duty as a director, except for liability as follows:

- for any breach of the director’s duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of laws;
- for unlawful payment of a dividend or unlawful stock purchase or stock redemption; and
- for any transaction from which the director derived an improper personal benefit.

The effect of these provisions is to eliminate our rights and our stockholders’ rights, through stockholders’ derivative suits on our behalf, to recover monetary damages against a director for a breach of fiduciary duty as a director, including breaches resulting from grossly negligent behavior, except in the situations described above.

EXHIBIT 21.1

Subsidiaries of the Company
At December 31, 2019

State or Jurisdiction of Organization	Subsidiaries	Ownership %
Delaware	COG Operating LLC	100%
Delaware	Mongoose Minerals LLC	100%
Delaware	RSP Permian, Inc.	100%
Delaware	RSP Permian, L.L.C.	100%
Texas	Concho Oil & Gas LLC	100%
Texas	Quail Ranch LLC	100%
Texas	COG Realty LLC	100%
Texas	COG Holdings LLC	100%
Texas	Delaware River SWD LLC	100%
Texas	COG Production LLC	100%
Texas	COG Acreage LP	100%

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 19, 2020, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Concho Resources Inc. on Form 10-K for the year ended December 31, 2019. We consent to the incorporation by reference of said reports in the Registration Statements of Concho Resources Inc. on Forms S-8 (File No. 333-145791, File No. 333-182046, File No. 333-204765 and File No. 333-231576) and on Forms S-3 (File No. 333-210309, File No. 333-213955, File No. 333-215560 and File No. 333-225609).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 19, 2020

EXHIBIT 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to (i) the use of the name Netherland, Sewell & Associates, Inc., the reference to our reserves report for Concho Resources Inc. (the "Company") dated January 23, 2020, and the use of information contained therein in the Company's annual report on Form 10-K to be filed on or about February 19, 2020, and (ii) inclusion of our summary report dated January 23, 2020, included in the Form 10-K to be filed on or about February 19, 2020, as Exhibit 99.1.

We hereby further consent to the incorporation by reference in the Registration Statements on (i) Form S-8 (file no. 333-145791), (ii) Form S-8 (file no. 333-182046), (iii) Form S-8 (file no. 333-204765), (iv) Form S-8 (file no. 333-231576), (v) Form S-3 (file no. 333-210309), (vi) Form S-3 (file no. 333-213955), (vii) Form S-3 (file no. 333-215560), and (viii) Form S-3 (file no. 333-225609) of such information.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (Scott) Rees III

C.H. (Scott) Rees III, P.E.

Chairman and Chief Executive Officer

Dallas, Texas
February 19, 2020

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Cawley, Gillespie & Associates, Inc., hereby consents to (i) the use of the oil and gas reserve information in the Concho Resources Inc. Securities and Exchange Commission Form 10-K for the year ending December 31, 2019 and in the Concho Resources Inc. annual report for the year ending December 31, 2019, based on the reserve report dated January 27, 2020, prepared by Cawley, Gillespie & Associates, Inc. and (ii) inclusion of our summary report dated January 27, 2020 included in the Form 10-K to be filed on or about February 19, 2020 as Exhibit 99.2.

We hereby further consent to the incorporation by reference in the Registration Statements on (i) Form S-8 (file no. 333-145791), (ii) Form S-8 (file no. 333-182046), (iii) Form S-8 (file no. 333-204765), (iv) Form S-8 (file no. 333-231576), (v) Form S-3 (file no. 333-210309), (vi) Form S-3 (file no. 333-213955), (vii) Form S-3 (file no. 333-215560) and (viii) Form S-3 (file no. 333-225609) of such information.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

J. Zane Meekins, P.E.
Executive Vice President

Fort Worth, Texas
February 19, 2020

EXHIBIT 31.1

CERTIFICATIONS

I, Timothy A. Leach, certify that:

1. I have reviewed this annual report of Concho Resources Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 19, 2020

/s/ Timothy A. Leach

Timothy A. Leach
Chairman of the Board of Directors and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATIONS

I, Brenda R. Schroer, certify that:

1. I have reviewed this annual report of Concho Resources Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 19, 2020

/s/ Brenda R. Schroer

Brenda R. Schroer
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

EXHIBIT 32.1

Certification of Chief Executive Officer of Concho Resources Inc.
(Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

In connection with the annual report of Concho Resources Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Timothy A. Leach, Chairman of the Board of Directors and Chief Executive Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

Date: February 19, 2020

/s/ Timothy A. Leach

Timothy A. Leach
Chairman of the Board of Directors and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 32.2

Certification of Chief Financial Officer of Concho Resources Inc.
(Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

In connection with the annual report of Concho Resources Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Brenda R. Schroer, Senior Vice President, Chief Financial Officer and Treasurer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to her knowledge:

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

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

Date: February 19, 2020

/s/ Brenda R. Schroer

Brenda R. Schroer
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

January 23, 2020

Mr. Keith Corbett
Concho Resources Inc.
One Concho Center
600 West Illinois Avenue
Midland, Texas 79701

Dear Mr. Corbett:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2019, to the Concho Resources Inc. (Concho) interest in certain oil and gas properties located in Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 45 percent of all proved reserves owned by Concho. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Concho's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Concho interest in these properties, as of December 31, 2019, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	191,528.3	744,337.0	7,005,062.1	3,669,430.3
Proved Developed Non-Producing	5,167.9	18,746.3	219,566.2	130,908.0
Proved Undeveloped	82,893.5	234,931.5	2,291,887.6	793,227.3
Total Proved	279,589.7	998,014.8	9,516,514.3	4,593,567.7

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Concho's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Concho's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2019. For oil volumes, the average West Texas Intermediate posted price of $52.19 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.577 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $50.85 per barrel of oil and $2.435 per MCF of gas.

Operating costs used in this report are based on operating expense records of Concho. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and $52.68 per well per month, which is Concho's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by Concho and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Concho interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Concho receiving its net revenue interest share of estimated future gross production. Additionally, we have been informed by Concho that it is not party to any firm transportation contracts for these properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Concho, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Concho, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Craig H. Adams, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1997 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Craig H. Adams
Craig H. Adams, P.E. 68137
Senior Vice President

Date Signed: January 23, 2020

CHA:MBG

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

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

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

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

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

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

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

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

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

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

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

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

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

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

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

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

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

> *From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*
>
> *Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.*
>
> *Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*
>
> - *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
> - *The company's historical record at completing development of comparable long-term projects;*
> - *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
> - *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
> - *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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306 WEST SEVENTH STREET
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(817) 336-2461

January 27, 2020

Mr. Keith Corbett
Sr. Vice President – Corporate Engineering & Planning
Concho Resources Inc.
One Concho Center
600 West Illinois Avenue
Midland, Texas 79701

Re: Evaluation Summary – SEC Pricing
Concho Resources Inc. Interests
Various States
Proved Reserves
As of December 31, 2019

Dear Mr. Corbett:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the above captioned interests as of December 31, 2019 for certain oil and gas properties located in Arkansas, New Mexico, Texas, Oklahoma, and Wyoming. We completed our evaluation on January 27, 2020. It is our understanding that the proved reserves estimated in this report constitute approximately 55 percent of all proved reserves owned by Concho Resources Inc.

This report has been prepared for Concho Resources Inc.'s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose. Composite reserve estimates and economic forecasts are summarized below:

		Total Proved	Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped
Net Reserves					
Oil/Condensate	- Mbbl	339,149.6	240,339.0	5,183.0	93,627.8
Gas	- MMcf	1,300,175.9	1,034,666.1	20,523.1	244,986.5
Operating Income (BFIT)	- M$	10,542,161.0	7,872,424.5	182,969.8	2,486,765.0
Discounted at 10%	- M$	6,034,579.0	4,737,218.0	119,089.6	1,178,270.3

In accordance with the Securities and Exchange Commission guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its "present worth". The discounted value, "present worth", shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The annual average Henry Hub spot market gas price of $2.577 per MMBtu and the annual average Plains WTI posted oil price of $52.19 per barrel were used. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for each month of 2019. The oil and gas prices were held constant and were adjusted for gravity, heating value, quality, transportation and marketing.

The adjusted volume-weighted average product prices over the life of the properties are $50.08 per barrel of oil and $1.63 per Mcf of gas.

Operating costs were based on operating expense records of Concho Resources. For non-operated properties, these costs include the overhead expenses allowed under existing joint operating agreements. Drilling and completion costs were based on estimates provided by Concho Resources and reviewed by Cawley, Gillespie & Associates. As per the Securities and Exchange Commission guidelines, neither expenses nor investments were escalated. The cost of plugging and the salvage value of equipment have not been considered.

The proved reserve classifications conform to criteria of the Securities and Exchange Commission. We used a combination of methods, including production performance analysis, analogy and volumetric analysis, we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. The possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Concho Resources. Ownership interests were supplied by Concho Resources and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc.

Cawley, Gillespie & Associates, Inc. is independent with respect to Concho Resources Inc. as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work-papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693