

SOUTHWESTERN ENERGY COMPANY
2019 ANNUAL REPORT



$\frac{R^2}{A} \rightarrow V^+$ ®



Bill Way
President and CEO

DEAR FELLOW SHAREHOLDERS

As I write this letter, our world is confronting unprecedented threats from COVID-19 to physical and economic health. All of us at Southwestern Energy extend our best wishes to you and your loved ones in these challenging times.

Being in a critical infrastructure industry, the people at SWN continue to responsibly produce clean energy to keep our nation and the world moving forward, demonstrating resilience in the face of volatile markets and an unwavering commitment to health and safety as we do so.

Just a few weeks ago we issued 2019 results and 2020 guidance, and I want to share our differentiated story as a leading Appalachia gas and liquids producer. SWN has operations across 460,000 acres in the Appalachia Basin. Our Tier 1 acreage in Pennsylvania and West Virginia includes a growing liquids exposure, and SWN has become one of the largest condensate producers in the region. Our concentrated asset portfolio is flexible, well-connected to low cost transportation and optimally positioned to supply growing U.S. and export demand for gas and liquids.

At the end of 2019, we had 12.7 trillion cubic feet equivalent of reserves and reported a 7% increase in reserves compared to the prior year. One-third of our reserves are liquids, and we added reserves across our acreage in both Pennsylvania and West Virginia. As a result of our cost reductions and increased reserves, we lowered our proved developed F&D by 24% to \$0.53 per Mcfe. Our investment in Southwest Appalachia has increased the liquids component of our production, which grew 23% in 2019.

OUR STRATEGY IN ACTION

Everything we do at Southwestern Energy reflects our strategy to drive shareholder value. Our people and our outperformance culture continue to consistently deliver strong quarterly and yearly performance and are driving the Company forward to the completion of our two year transition plan back to cash flow neutrality. This reflects a plan, a portfolio and an exceptionally talented team that are agile and resilient, even in the challenging environment the industry faces today.

We have fundamentally changed the way we look at every cost and every process, so that the Company can thrive in lower commodity price cycles. We are relentless in our efforts to continue to improve operational efficiencies, reduce costs and position ourselves to take advantage of

value enhancing opportunities. The transformational changes we have made to date, our high quality asset base and our disciplined capital allocation strategy all bolster the resilience of the Company. We continue to take actions to return to free cash flow neutral.

Our well established and robust rolling three-year hedging program is designed to provide protection for the Company's cash flow, while retaining the opportunity to capture upside should market fundamentals improve. We are well hedged for 2020 with 83% of gas and 100% of our oil production protected from commodity price volatility. The improving productivity from our existing asset base resulting from continuous technical enhancements, operational efficiencies and sustainable cost-saving improvements will continue to elevate the value of our Appalachia reserve base.

Our focus on converting resource to reserves will continue as we push to increase returns and improve margins. We will opportunistically grow, seeking the highest value-creating opportunities for our shareholders.

2019 ACHIEVEMENTS DRIVING FUTURE PERFORMANCE

Our 2019 accomplishments have set us up for continued outperformance in 2020.

Because of our capital efficiencies and cost reductions, we are able to do more with less capital. **We have reduced well costs materially, but we are not done. In 2020, we expect to reduce well costs an additional \$100 per lateral foot.** We have repositioned our Company to be a leading Appalachia condensate producer, with our condensate production increasing 38%. In 2019, we received \$180 million of settled derivative gains and have a majority of our 2020 production hedged at prices well above the current strip. We are continuing our focus on cutting costs, adding an additional \$40 million in G&A savings in 2020 to our \$122 million of G&A and interest savings in 2019. All of this was accomplished while remaining good environmental stewards.

TOP TIER BALANCE SHEET

A clear differentiator for Southwestern Energy is our peer leading five-year maturity window. As we execute our business plan in 2020, we remain sharply focused on maintaining the strength of our balance sheet, which is critical to our long-term success. At year-end 2019, we had \$1.8 billion of available liquidity under our \$2 billion bank facility, a net debt to EBITDA ratio of 2.3 times and no material debt maturities before 2025, and thus no looming high cost re-financing risk. During 2019, we repurchased \$62 million of senior notes at an average discount of 13% and retired the remaining \$52 million of our 2020

senior notes, leaving a total of \$2.2 billion of senior notes outstanding, with a weighted average interest rate of 6.7%.

SUPERIOR LIQUIDS-RICH ACREAGE

The pace of change we've pursued in our liquids-rich acreage over the last three years is particularly noteworthy. In that time, we have become a major liquids player in the Appalachia Basin. We have over 108,000 liquids-rich acres, which is more than eight years of inventory. Our superior condensate acreage position is the largest in the Appalachia Basin and, compared to our peers, provides the highest yields. We yield manage our production from our super rich acreage in West Virginia to maximize condensate production, provide economic uplift and improve returns. In 2019, liquids were approximately 22% of total production, increasing 23% to almost 78,000 barrels per day. In 2020, we expect liquids production to grow to more than 87,000 barrels per day by continued investment in our liquids-rich acreage. We exited the year 2019 with more than 16,000 barrels per day of condensate production, which we expect to grow 25% in 2020.

VERTICAL INTEGRATION

I'd like to comment on the clear strategic and economic benefits of our vertical integration strategy. We own super-spec drilling rigs and one fracture stimulation fleet. The crews that operate that equipment are SWN employees. **Our crews have deep experience, operate safely and are a valuable asset to our Company because they are vested in SWN.** They are loyal, creative and innovative. We have been vertically integrated for years, and our operational execution proves this advantage. Many of our peers have tried vertical integration and failed; SWN is already through the learning curve that is a barrier to others. Vertical integration is a competitive advantage through several means because it keeps costs competitive, enables us to consistently achieve new performance records through superior execution, and provides opportunity for strategic capability, which is linking data analytics to people and equipment to achieve performance breakthroughs.

RELENTLESS COST MANAGEMENT

Our cost focus is unyielding and our teams continue to exceed expectations. In 2019, we reduced total well cost by 27% to an average of \$824 per lateral foot. We also set a new record low well cost of \$605 per lateral foot and a record lateral of over 18,000 feet, meaning we have more runway to go. We

achieved this result through an integrated approach to planning, sourcing, logistics, application of leading technology and exceptional implementation by highly talented people. Supporting this fully integrated approach, we self-sourced sand, realized the benefits of our completed water pipeline systems, increased lateral lengths and reduced cycle times to exceed our well cost reduction target. In 2020, we are pursuing additional well cost reductions to \$730 per lateral foot for wells to sales. These costs are fully loaded, and include both dry gas and liquids-rich wells. Strategic leasing and optimized pad utilization allowed us to average drilled lateral lengths in excess of 10,000 feet in 2019, which is moving 20% higher to 12,000 feet this year. Lateral lengths will continue to expand as we block up further acreage, with 24 ultra-long laterals, which are greater than 15,000 feet, included in this year's program.

LEADER IN ESG

Now let's turn to a core value of our Company--responsible development of energy must include a relentless focus and commitment to the health and safety of our workers and the protection of our environment. Every day, our employees demonstrate their care for the environment and are leaders in safety, emphasizing that anyone who works for our Company should go home each day in the condition they started the day – in other words, that no one gets hurt.

During 2019, we achieved the lowest recordable injury rate in the Company's history. Our safety effort includes contractors who work on our behalf, as well as employees, all working as One Team at SWN. This Company is among the very best at providing and nurturing a safe workplace.

Our active participation in environmental stewardship is well demonstrated by our ongoing commitment to return fresh water to areas where we operate in greater amounts than we consume. **We just surpassed 11 billion gallons of fresh water returned to the environment.** As a leading natural gas and gas liquids producer, we are well-positioned in a low carbon energy future with demonstrated results in reducing emissions. Minimizing GHG emissions is a core operating philosophy for SWN. We have advanced leak detection technology at 100% of our facilities and have a leak/loss rate that is a fraction of the national average.

BUILDING LONG-TERM SHAREHOLDER VALUE

Thank you for being a shareholder in SWN and allowing me to give an update on where we've been, where we are and where we're headed. **We have consistently delivered on every commitment that we make on our clear and determined plan to**

reposition the Company--that's a hallmark of how we operate.

We realize it is a tough market, but Southwestern continues to thoughtfully navigate the challenges and opportunities ahead. We are driven by returns-focused investment and defined by demonstrating rigorous financial discipline. Our efforts are led by operational and technical excellence, margin expansion through cost reductions and improved well productivity, all the while driving differentiation through vertical integration, safety, and environmental stewardship. We are always thinking about ideas and opportunities to add value beyond our current asset base. We will evaluate those ideas with the clarity, rigor, and discipline that you've gotten to know us for, and with a keen eye to assuring that there is real long-term value creation and that long-term value creation is deliverable when we say it can be delivered.

LOOKING AHEAD

As we look into 2020 and beyond, we will be unrelenting in our commitment to mitigate the challenges faced by our industry and to help our country combat and recover from the impact of COVID-19 on our people and economy. I want to thank our teams for their outstanding service that helped us to deliver strong results in 2019 and look forward to carrying that outperformance culture forward. On behalf of SWN, its Board of Directors and all of our employees, we sincerely thank you for your continued investment and support.



Bill Way
President and Chief Executive Officer
Southwestern Energy

Directors



From left to right: **John D. Gass** (7), Retired–Chevron Corporation; **Anne Taylor** (1), Retired–Deloitte; **Jon Marshall** (2), Retired–Transocean Ltd.; **Denis J. Walsh III** (*), Retired–BlackRock Inc.; **Catherine A. Kehr** (8), Retired–The Capital Group Companies; **Greg D. Kerley** (9), Retired–CFO Southwestern Energy Company; **Patrick M. Prevost** (2), Retired–Cabot Corporation; **William J. Way** (4), President and Chief Executive Officer

Executive Officers



William J. Way (8)
President and Chief Executive Officer



Julian M. Bott (2)
Executive Vice President and Chief Financial Officer



Clayton A. Carrell (2)
Executive Vice President and Chief Operating Officer



J. David Cecil (2)
Executive Vice President–Corporate Development



John C. Ale (6)
Senior Vice President General Counsel and Secretary



Jennifer N. McCauley (10)
Senior Vice President–Administration



Jason Kurtz (22)
Vice President–Marketing and Transportation

Corporate Officers

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President and Chief Executive Officer

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Executive Vice President and Chief Financial Officer

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Executive Vice President and Chief Operating Officer

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Executive Vice President–Corporate Development

John C. Ale (6)
Senior Vice President General Counsel and Secretary

Jennifer N. McCauley (10)
Senior Vice President–Administration

Randall L. Barron (17)
Vice President and Treasurer

Brittany D. Benko (*)
Vice President of Health, Safety, Environment and Regulatory

Carina L. Gillenwater (1)
Vice President–Human Resources

Michael E. Hancock (9)
Vice President–Financial Planning and Analysis

Andrew T. Huggins (12)
Vice President–Commercial Development

Jason Kurtz (22)
Vice President–Marketing and Transportation

Seema Menon (9)
Vice President–Business Information Systems

Colin P. O’Beirne (9)
Vice President and Controller

C. Paige Penchas (2)
Vice President–Investor Relations

Operating Subsidiary Officers

Derek W. Cutright (11)
Senior Vice President–Southwest Appalachia Division

William Q. Dyson (2)
Senior Vice President–Operations Services

John P. Kelly Jr. (2)
Senior Vice President–Northeast Appalachia Division

For Directors, years served on the Board of Directors are shown on this page in parentheses, and an asterisk (*) indicates less than one year of service.

For Executive Officers, years with the Company are shown on this page in parentheses, and an asterisk (*) indicates less than one year of service.

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**
Commission file number **001-08246**

SWN

Southwestern Energy®

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

Delaware

71-0205415

(State or other jurisdiction of incorporation or organization)

(I.R.S. Employer Identification No.)

**10000 Energy Drive
Spring, Texas 77389**

(Address of principal executive offices)(Zip Code)

(832) 796-1000

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

<u>Title of each class</u>	<u>Trading Symbol(s)</u>	<u>Name of each exchange on which registered</u>
Common Stock, Par Value \$0.01	SWN	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 Act). Yes No

The aggregate market value of the voting stock held by non-affiliates of the registrant was \$1,703,566,444 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2019 of \$3.16. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 25, 2020, the number of outstanding shares of the registrant's Common Stock, par value \$0.01, was 541,057,922.

Document Incorporated by Reference

Portions of the registrant's definitive proxy statement to be filed with respect to the annual meeting of stockholders to be held on or about May 19, 2020 are incorporated by reference into Part III of this Form 10-K.

SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2019

TABLE OF CONTENTS

	<u>Page</u>
<u>PART I</u>	
Item 1.	Business 4
	Glossary of Certain Industry Terms 25
Item 1A.	Risk Factors 29
Item 1B.	Unresolved Staff Comments 40
Item 2.	Properties 40
Item 3.	Legal Proceedings 45
Item 4.	Mine Safety Disclosures 45
<u>PART II</u>	
Item 5.	Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities 46
	Stock Performance Graph 47
Item 6.	Selected Financial Data 48
Item 7.	Management’s Discussion and Analysis of Financial Condition and Results of Operations 50
	Overview 50
	Results of Operations 51
	Liquidity and Capital Resources 59
	Critical Accounting Policies and Estimates 65
	Cautionary Statement about Forward-Looking Statements 68
Item 7A.	Quantitative and Qualitative Disclosures about Market Risk 70
Item 8.	Financial Statements and Supplementary Data 71
	Index to Consolidated Financial Statements 71
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure 133
Item 9A.	Controls and Procedures 133
Item 9B.	Other Information 133
<u>PART III</u>	
Item 10.	Directors, Executive Officers and Corporate Governance 134
Item 11.	Executive Compensation 134
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters 135
Item 13.	Certain Relationships and Related Transactions, and Director Independence 135
Item 14.	Principal Accounting Fees and Services 135
<u>PART IV</u>	
Item 15.	Exhibits, Financial Statement Schedules 135
Item 16.	Form 10-K Summary 135

EXHIBIT INDEX

This Annual Report on Form 10-K (“Annual Report”) includes certain statements that may be deemed to be “forward-looking” within the meaning of Section 27A of the Securities Act of 1933, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to “Risk Factors” in Item 1A of Part I and to “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements” in Item 7 of Part II of this Annual Report for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements. The electronic version of this Annual Report, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, the Compensation, the Health, Safety, Environment and Corporate Responsibility and the Nominating and Governance Committees of our Board of Directors are available on our website and, upon request, in print free of charge to any stockholder. Information on our website is not incorporated into this report.

We file periodic reports, current reports and proxy statements with the SEC electronically. The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of the SEC’s website is www.sec.gov. The public may also read and copy any materials we file with the SEC at the SEC’s Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

PART I

ITEM 1. BUSINESS

Southwestern Energy Company (including its subsidiaries, collectively, “we”, “our”, “us”, “the Company” or “Southwestern”) is an independent energy company engaged in exploration, development and production activities, including the related marketing of natural gas, oil and natural gas liquids (“NGLs”) produced in our operations. Southwestern is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries. Currently we operate exclusively in the United States. Our common stock is listed and traded on the NYSE under the ticker symbol “SWN.”

Southwestern, which is incorporated in Delaware, has its executive offices located at 10000 Energy Drive, Spring, Texas 77389, and can be reached by phone at 832-796-1000. The Company also maintains offices in Tunkhannock, Pennsylvania and Morgantown, West Virginia.

Our Business Strategy

We aim to deliver sustainable and industry-leading returns through excellence in exploration and production and marketing performance from our extensive resource base and targeted expansion of our activities and assets along the hydrocarbon value chain. Our Company’s formula embodies our corporate philosophy and guides how we operate our business:

$$\frac{R^+}{A} \rightarrow V^+$$

Our formula, “The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets will create Value+,” also guides our business strategy. We always strive to attract and retain strong talent, to work safely and act ethically with unwavering vigilance for the environment and the communities in which we operate, and to creatively apply technical skills, which we believe will grow long-term value for our shareholders. The arrow in our formula is not a straight line: we acknowledge that factors may adversely affect quarter-by-quarter results, but the path over time points to value creation.

In applying these core principles, we concentrate on:

- **Financial Strength.** We are committed to rigorously managing our balance sheet and financial risks. We budget to invest from our net cash flow from operations, supplemented during 2019 and 2020 by a portion of the proceeds from the 2018 Fayetteville Shale sale (described below). Additionally, we protect our projected cash flows through hedging and continue to maintain a strong balance sheet with ample liquidity.
- **Increasing Margins.** We apply strong technical, operational, commercial and marketing skills to reduce costs, improve the productivity of our wells and pursue commercial arrangements to extract greater value. We believe our demonstrated ability to improve margins, especially by leveraging the scale of our large assets, gives us a competitive advantage as we move into the future.
- **Exercising Capital Allocation Discipline.** We continually assess market conditions in order to adjust our capital allocation decisions to maximize shareholder returns. This allocation process includes consideration of multiple alternatives including but not limited to the development of our natural gas and oil assets, strategic acquisitions, reducing debt and returning capital to our shareholders.
- **Operational Value Creation.** We prepare an economic analysis for our drilling programs and other investments based upon the expected net present value added for each dollar to be invested, which we refer to as Present Value Index, or PVI. We target projects that generate the highest returns in excess of our cost of capital. This disciplined investment approach governs our investment decisions at all times, including the current lower-price commodity market.
- **Dynamic Management of Assets Throughout Life Cycle.** We own large-scale, long-life assets in various phases of development. In early stages, we ramp up development through technical, operational and commercial skills, and as they grow we look for ways to maximize their value through efficient operating practices along with applying our commercial and marketing expertise.
- **Deepening Our Inventory.** We continue to expand the inventory of properties that we can develop profitably by converting our extensive resources into proved reserves, targeting additions whose productivity largely has been demonstrated and improving efficiencies in production.

- ***The Hydrocarbon Value Chain.*** We believe that our vertical integration enhances our margins and provides us competitive advantages. For example, we own and operate drilling rigs and well stimulation equipment and have invested in a water transportation project in West Virginia, which has provided up to \$0.8 million in savings per well. These activities provide operational flexibility, lower our well costs, minimize the risk of unavailability of these resources from third parties and capture additional value over time.
- ***Technological Innovation.*** Our people constantly search for the next revolutionary technology and other operational advancements to capture greater value in unconventional hydrocarbon resource development. These developments – whether single, step-changing technologies or a combination of several incremental ones – can reduce finding and development costs and thus increase our margins.
- ***Environmental Solutions and Policy Formation.*** We are a leader in identifying and implementing innovative solutions to unconventional hydrocarbon development to minimize the environmental and community impacts of our activities. We work extensively with governmental, non-governmental and industry stakeholders to develop responsible and cost-effective programs. We demonstrate that a company can operate responsibly and profitably, putting us in a better position to comply with new regulations as they evolve.

During 2019 we executed on these business strategies by:

- Shifting strategic focus to our liquids-rich portfolio in Southwest Appalachia to take advantage of more favorable commodity pricing;
- Lowering our costs through drilling, completions and operational efficiencies and optimizing gathering and transportation costs;
- Continuing to identify and implement structural, process and organizational changes to further reduce general and administrative costs;
- Improving our debt profile by opportunistically repurchasing debt at a discount and extending the maturity of our revolving credit facility to 2024;
- Maintaining a robust multi-year hedging program to ensure a certain level of cash flow;
- Focusing on delivering operational excellence with improved well productivity and economics from enhanced completion techniques, water infrastructure projects, optimization of surface equipment and managing reservoir drawdown; and
- Expanding our proved reserve quantities in Appalachia through our successful drilling program, lower cost structure and improved operational performance.

The bulk of our operations, which we refer to as “Exploration and Production” (“E&P”), are focused on the finding and development of natural gas, oil and NGL reserves. We are also focused on creating and capturing additional value through our marketing business, which we refer to as “Marketing” but previously referred to as “Midstream” when it included the operation of gathering systems.

On December 3, 2018, we completed the sale of 100% of the equity in certain of our subsidiaries that conducted our operations in Arkansas, which were primarily focused on the Fayetteville Shale (the “Fayetteville Shale sale”). We refer you to Note 3 to the consolidated financial statements included in the Annual Report for additional discussion about the Fayetteville Shale sale.

Exploration and Production

Overview

Our primary business is the exploration for, and production of, natural gas, oil and NGLs, with our current operations solely within the United States. We are currently focused on the development of unconventional natural gas reservoirs located in Pennsylvania and West Virginia. Our operations in northeast Pennsylvania (herein referred to as “Northeast Appalachia”) are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale, and our operations in West Virginia and southwest Pennsylvania (herein referred to as “Southwest Appalachia”) are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas, oil and NGL reservoirs. Collectively, our properties located in Pennsylvania and West Virginia are herein referred to as “Appalachia.”

- Our E&P segment recorded operating income of \$283 million in 2019, compared to \$794 million in 2018. Operating income for the fiscal year 2018 included \$105 million related to operations in the Fayetteville Shale, which was sold in December 2018. Excluding our 2018 operating income from the Fayetteville Shale, our E&P segment operating income decreased \$406 million in 2019 from 2018 primarily due to a \$285 million decrease in revenues and a \$121 million increase in operating expenses. The decrease in revenues was primarily due to lower commodity prices, which were only partially offset by higher production. Operating expenses increased primarily due to increased gathering and processing fees resulting from a shift to liquids-rich production growth in Southwest Appalachia and increased depreciation, depletion and amortization. These results do not include the effects of our derivative program.
- Cash flow from operations from our E&P segment was \$781 million in 2019, compared to \$1.4 billion in 2018. Cash flow from operations for 2018 included \$236 million related to our operations in the Fayetteville Shale. Excluding our cash flow from operations from the Fayetteville Shale, our cash flow from operations decreased \$368 million in 2019 from 2018 primarily as a 10% decrease in weighted average commodity prices, including derivatives, and increased operating expenses associated with higher liquids activity more than offset an 11% increase in Appalachia production volumes.

Oilfield Services Vertical Integration

We provide certain oilfield services that are strategic and economically beneficial for our E&P operations when our E&P activity levels and market pricing support these activities. This vertical integration lowers our well costs, allows us to operate efficiently and helps us to mitigate certain operational and environmental risks. These services have included drilling, hydraulic fracturing and water management and movement.

As of December 31, 2019, we operated seven drilling rigs and two leased pressure pumping spreads with a total capacity of approximately 72,000 horsepower. These assets provide us greater flexibility to align our operational activities with commodity prices. In 2019, we provided drilling rigs for all of our 105 drilled wells. In addition, we provided hydraulic fracturing services utilizing one pressure pumping spread in Southwest Appalachia.

Our Proved Reserves

	For the years ended December 31,		
	2019	2018	2017
Proved reserves: (Bcfe)			
Appalachia	12,720	11,920	11,088
Fayetteville Shale	—	—	3,679
Other	1	1	8
Total proved reserves	12,721	11,921	14,775
Prices used:			
Natural gas (per Mcf)	\$ 2.58	\$ 3.10	\$ 2.98
Oil (per Bbl)	\$ 55.69	\$ 65.56	\$ 47.79
NGL (per Bbl)	\$ 11.58	\$ 17.64	\$ 14.41
PV-10: (in millions)			
Pre-tax	\$ 3,735	\$ 6,524	\$ 5,784
PV of taxes	(35)	(525)	(222)
After-tax	\$ 3,700	\$ 5,999	\$ 5,562
Percent of estimated proved reserves that are:			
Natural gas	68 %	67 %	75 %
Proved developed	50 %	47 %	54 %
Percent of E&P operating revenues generated by natural gas sales	71 %	78 %	85 %

Our reserve estimates and the after-tax PV-10 measure, or standardized measure of discounted future net cash flows relating to proved natural gas, oil and NGL reserve quantities, are highly dependent upon the respective commodity price used in our reserve and after-tax PV-10 calculations.

- Our reserves increased 7% in 2019, compared to 2018, primarily through extensions, discoveries and other additions, along with positive performance revisions.
- The decrease in our reserves in 2018, compared to 2017, was primarily due to the Fayetteville Shale sale. Excluding the impact of the Fayetteville Shale sale, our reserves increased 7% in 2018, compared to 2017, primarily through extensions, discoveries and other additions, along with increases in both price and performance revisions in Appalachia.
- Our after-tax PV-10 value decreased in 2019 compared to 2018 as higher reserve levels and lower future development and production costs were more than offset by lower commodity prices.
- We are the designated operator of approximately 99% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index was approximately 16.4 years at year-end 2019.

The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2019 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows.

We believe that the pre-tax PV-10 value of the estimated cash flows related to our estimated proved reserves is a useful supplemental disclosure to the after-tax PV-10 value. Pre-tax PV-10 is based on prices, costs and discount factors that are comparable from company to company, while the after-tax PV-10 is dependent on the unique tax situation of each individual company. We understand that securities analysts use pre-tax PV-10 as one measure of the value of a company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We refer you to "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report for a discussion of our standardized measure of discounted future cash flows related to our proved natural gas, oil and NGL reserves, to the risk factor "Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material change to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A of Part I of this Annual Report, and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Lower natural gas, oil and NGL prices reduce the value of our assets, both by a direct reduction in what the production could be sold for and by making some properties uneconomic, resulting in decreases to the overall value of our reserves and potential non-cash impairment charges to earnings. Given the fall in commodity prices in 2019 and early 2020 and assuming that commodity prices remain at January 2020 levels for the rest of the first quarter of 2020, we expect a non-cash impairment to our natural gas and oil properties in the first quarter of 2020 ranging from approximately \$400 million to \$600 million, net of tax. Further non-cash impairments in future periods could occur if the trailing 12-month commodity prices decrease as compared to the average used in prior periods.

The following table provides an overall and categorical summary of our natural gas, oil and NGL reserves, as of year-end 2019 based on average year prices, and our well count, net acreage and PV-10 as of December 31, 2019, and sets forth 2019 annual information related to production and capital investments for each of our operating areas:

2019 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	<u>Appalachia</u>		<u>Other ⁽¹⁾</u>	<u>Total</u>
	<u>Northeast</u>	<u>Southwest</u>		
Estimated proved reserves:				
Natural gas (Bcf):				
Developed	3,570	1,336	—	4,906
Undeveloped	1,267	2,457	—	3,724
	<u>4,837</u>	<u>3,793</u>	—	<u>8,630</u>
Crude oil (MMBbls):				
Developed	—	26.0	0.1	26.1
Undeveloped	—	46.8	—	46.8
	—	<u>72.8</u>	0.1	<u>72.9</u>
Natural gas liquids (MMBbls):				
Developed	—	226.3	—	226.3
Undeveloped	—	382.5	—	382.5
	—	<u>608.8</u>	—	<u>608.8</u>
Total proved reserves (Bcfe) ⁽²⁾ :				
Developed	3,570	2,850	1	6,421
Undeveloped	1,267	5,033	—	6,300
	<u>4,837</u>	<u>7,883</u>	1	<u>12,721</u>
Percent of total	38 %	62 %	0%	100 %
Percent proved developed	74 %	36 %	100 %	50 %
Percent proved undeveloped	26 %	64 %	0%	50 %
Production (Bcfe)	459	319	—	778
Capital investments (in millions)	\$ 365	\$ 710	\$ 63 ⁽³⁾	\$ 1,138
Total gross producing wells ⁽⁴⁾	1,211	496	14	1,721
Total net producing wells	637	466	14	1,117
Total net acreage	173,994	287,693	40,389 ⁽⁵⁾	502,076
Net undeveloped acreage	53,435	205,222	27,334 ⁽⁵⁾	285,991
PV-10:				
Pre-tax (in millions) ⁽⁶⁾	\$ 2,251	\$ 1,486	\$ (2) ⁽⁷⁾	\$ 3,735
PV of taxes (in millions) ⁽⁶⁾	(21)	(14)	—	(35)
After-tax (in millions) ⁽⁶⁾	<u>\$ 2,230</u>	<u>\$ 1,472</u>	<u>\$ (2) ⁽⁷⁾</u>	<u>\$ 3,700</u>
Percent of total	60 %	40 %	0%	100 %
Percent operated ⁽⁸⁾	99 %	100 %	100 %	99 %

(1) Other reserves and acreage consists primarily of properties in Colorado.

(2) We have no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. We used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis, offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

(3) Other capital investments includes \$35 million related to our water infrastructure project, \$22 million related to our E&P service companies and \$6 million related to other developmental activities.

(4) Represents producing wells, including 516 wells in which we only have an overriding royalty interest in Northeast Appalachia, used in the December 31, 2019 reserves calculation.

(5) Excludes exploration licenses for 2,518,519 net acres in New Brunswick, Canada, which have been subject to a moratorium since 2015.

- (6) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company's proved reserves that we believe is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved natural gas, oil and NGL reserves.
- (7) Includes future asset retirement obligations outside of Appalachia.
- (8) Based upon pre-tax PV-10 of proved developed producing activities.

Lease Expirations

The following table summarizes the leasehold acreage expiring over the next three years, assuming successful wells are not drilled to develop the acreage and leases are not extended:

	For the years ended December 31,		
	2020	2021	2022
Net acreage expiring:			
Northeast Appalachia	3,082 ⁽¹⁾	1,750	4,567
Southwest Appalachia ⁽²⁾	15,584 ⁽¹⁾	5,804	14,536
Other			
US – Other Exploration	11,949	5,679	650
US – Sand Wash Basin	5,630	3,425	—
Canada – New Brunswick ⁽³⁾	—	2,518,519	—

- (1) We have no reported proved undeveloped locations expiring in 2020.
- (2) Of this acreage, 1,726 net acres in 2020, 2,173 net acres in 2021 and 6,907 net acres in 2022 can be extended for an average of 4.9 years.
- (3) Exploration licenses were extended through 2021 but have been subject to a moratorium since 2015.

We refer you to “Supplemental Oil and Gas Disclosures” in Item 8 of Part II of this Annual Report for a more detailed discussion of our proved natural gas, oil and NGL reserves as well as our standardized measure of discounted future net cash flows related to our proved natural gas, oil and NGL reserves. We also refer you to the risk factor “Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material changes to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated” in Item 1A of Part I of this Annual Report and to “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements” in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Proved Undeveloped Reserves

Presented below is a summary of changes in our proved undeveloped reserves for 2017, 2018 and 2019:

CHANGES IN PROVED UNDEVELOPED RESERVES

<i>(in Bcfe)</i>	Appalachia		Fayetteville	Total
	Northeast	Southwest	Shale ⁽¹⁾	
December 31, 2016	34	—	43	77
Extensions, discoveries and other additions ⁽²⁾	1,100	5,186	543	6,829
Performance and production revisions ⁽³⁾	—	6	(14)	(8)
Price revisions	2	—	1	3
Developed	(17)	—	(29)	(46)
Disposition of reserves in place	—	—	—	—
Acquisition of reserves in place	—	—	—	—
December 31, 2017	1,119	5,192	544	6,855
Extensions, discoveries and other additions	397	435	—	832
Performance and production revisions ⁽³⁾	39	217	—	256
Price revisions	8	53	—	61
Developed	(524)	(572)	—	(1,096)
Disposition of reserves in place	—	—	(544)	(544)
Acquisition of reserves in place	—	—	—	—
December 31, 2018	1,039	5,325	—	6,364
Extensions, discoveries and other additions	677	327	—	1,004
Performance and production revisions ⁽³⁾	(40)	723	—	683
Reclassification of PUD to unproved under SEC five-year rule ⁽⁴⁾	—	(109)	—	(109)
Price revisions	(12)	(395)	—	(407)
Developed	(397)	(838)	—	(1,235)
Disposition of reserves in place	—	—	—	—
Acquisition of reserves in place	—	—	—	—
December 31, 2019	1,267	5,033	—	6,300

- (1) The Fayetteville Shale E&P assets and associated reserves were sold in December 2018.
- (2) The 2017 proved undeveloped, or PUD, additions of 6,829 Bcfe were comprised of 3,910 Bcfe attributable to adding new undeveloped locations throughout the year through our successful drilling program and 2,919 Bcfe attributable to adding undeveloped locations associated with increased commodity pricing across our portfolio.
- (3) Primarily due to changes associated with the analysis of updated data collected in the year and decreases related to current year production.
- (4) Consists of reserves associated with planned wells that were PUD at the beginning of the year but were subsequently reclassified to unproved due to changes in the drilling plan, in accordance with the SEC five-year rule.

Performance, production and price revisions consist of revisions to reserves associated with wells having proved reserves in existence as of the beginning of the year. Extensions, discoveries and other additions include new reserves locations added in the current year. Certain planned wells that were proved undeveloped as of the beginning of the year have been rescheduled beyond five years. Accordingly, the proved undeveloped reserves associated with these planned wells have been removed as they now fall outside of the SEC mandated five-year development window. We expect these previous proved undeveloped reserves to be added back in future years.

- As of December 31, 2019, we had 6,300 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2019, we invested \$638 million in connection with converting 1,235 Bcfe, or 19%, of our proved undeveloped reserves as of December 31, 2018 into proved developed reserves and added 1,004 Bcfe of proved undeveloped reserves. As a result of the commodity price environment in 2019, we had downward price revisions of 407 Bcfe. In addition, we also had 109 Bcfe that was reclassified to unproved. These reductions were more than offset by a 683 Bcfe increase due to performance and production revisions.
- As of December 31, 2018, we had 6,364 Bcfe of proved undeveloped reserves. During 2018, we invested \$491 million in connection with converting 1,096 Bcfe, or 16%, of our proved undeveloped reserves as of December 31, 2017 into

proved developed reserves and added 832 Bcfe of proved undeveloped reserve additions in Appalachia. Proved undeveloped reserves also decreased in 2018 primarily due to the sale of the Fayetteville Shale E&P assets.

- As of December 31, 2017, we had 6,855 Bcfe of proved undeveloped reserves. During 2017, we invested \$23 million in connection with converting 46 Bcfe, or 60%, of our proved undeveloped reserves as of December 31, 2016 into proved developed reserves and added 6,829 Bcfe of proved undeveloped reserve additions in Appalachia. The significant increase in our proved undeveloped reserve additions in 2017 was the result of adding new undeveloped locations throughout the year through our successful drilling program, improved operational performance and increased commodity pricing across our portfolio.

Our December 31, 2019 proved reserves included 929 Bcfe of proved undeveloped reserves from 90 locations that have a positive present value on an undiscounted basis in compliance with proved reserve requirements but do not have a positive present value when discounted at 10%. These properties have a negative present value of \$50 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves within five years from the date of initial booking.

We expect that the development costs for our proved undeveloped reserves of 6,300 Bcfe as of December 31, 2019 will require us to invest an additional \$3.0 billion for those reserves to be brought to production. Our ability to make the necessary investments to generate these cash inflows is subject to factors that may be beyond our control. The current commodity price environment has resulted, and could continue to result, in certain reserves no longer being economic to produce, leading to both lower proved reserves and cash flows. We refer you to the risk factors “Natural gas, oil and NGL prices greatly affect our revenues and thus profits, liquidity, growth, ability to repay our debt and the value of our assets” and “Significant capital investment is required to replace our reserves and conduct our business” in Item 1A of Part I of this Annual Report and to “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements” in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Reserve Replacement

The reserve replacement ratio measures the success of an E&P company in adding new reserves to replace the reserves that are being depleted by its current production volumes. The reserve replacement ratio, which we discuss below, is an important analytical measure used by investors and peers in the E&P industry to evaluate performance results and long-term prospects. There are limitations as to the usefulness of this measure, as it does not reflect the type of reserves or the cost of adding the reserves or indicate the potential value of the reserve additions.

In 2019, we replaced 203% of our production volumes with 1,195 Bcfe of proved reserve additions and net upward revisions of 385 Bcfe, all of which were from Appalachia. The following table summarizes the changes in our proved natural gas, oil and NGL reserves for the year ended December 31, 2019:

(in Bcfe)	Appalachia		Other ⁽¹⁾	Total
	Northeast	Southwest		
December 31, 2018	4,366	7,554	1	11,921
Net revisions				
Price revisions	(57)	(660)	—	(717)
Performance and production revisions	127	975	—	1,102
Total net revisions	70	315	—	385
Extensions, discoveries and other additions				
Proved developed	185	6	—	191
Proved undeveloped	677	327	—	1,004
Total reserve additions	862	333	—	1,195
Production	(459)	(319)	—	(778)
Acquisition of reserves in place	—	—	—	—
Disposition of reserves in place	(2)	—	—	(2)
December 31, 2019	4,837	7,883	1	12,721

(1) Other includes properties outside of Appalachia.

Our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors “Significant capital investment is required to replace our reserves and conduct our business” and “If we are not able to replace reserves, we may not be able to grow or sustain production.” in Item 1A of Part I of this Annual Report and to “Management’s

Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements” in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Operations

Northeast Appalachia

Northeast Appalachia represented 59% of our total 2019 net production and 38% of our total reserves as of December 31, 2019. In 2019, our reserves in Northeast Appalachia increased by 471 Bcf, which included net additions of 862 Bcf and net upward performance revisions of 127 Bcf, partially offset by net downward price revisions of 57 Bcf, disposition of reserves in place of 2 Bcf and production of 459 Bcf. As of December 31, 2019, we had approximately 173,994 net acres in Northeast Appalachia and had spud or acquired 727 operated wells, 641 of which were on production. Below is a summary of Northeast Appalachia’s operating results for the latest three years:

	For the years ended December 31,		
	2019	2018	2017
Acreage			
Net undeveloped acres	53,435 ⁽¹⁾	73,174	87,927
Net developed acres	120,559	110,850	103,299
Total net acres	173,994	184,024	191,226
Net Production (Bcf)	459	459	395
Reserves			
Reserves (Bcf)	4,837	4,366	4,126
Locations:			
Proved developed producing	1,211	1,042	983
Proved developed non-producing	14	21	25
Proved undeveloped	82	82	100
Total locations	1,307 ⁽²⁾	1,145	1,108
Gross Operated Well Count Summary			
Drilled	39	41	67
Completed	44	54	77
Wells to sales	44	60	83
Capital Investments (in millions)			
Drilling and completions, including workovers	\$ 314	\$ 370	\$ 420
Acquisition and leasehold	13	14	14
Seismic and other	5	3	13
Capitalized interest and expense	33	35	42
Total capital investments	\$ 365	\$ 422	\$ 489
Average completed well cost (in millions)	\$ 7.3	\$ 7.5	\$ 5.9
Average lateral length (feet)	9,029	7,584	6,185

(1) Our undeveloped acreage position as of December 31, 2019 had an average royalty interest of 15%.

(2) Includes 516 proved developed producing and 3 proved developed non-producing wells in which we have only an overriding royalty interest.

For 2019 as compared to 2018:

- Our average completed well cost per foot decreased primarily due to increased lateral lengths, operational execution and savings from vertical integration and direct-sourcing sand.

Our ability to bring our Northeast Appalachia production to market depends on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to “Marketing” in Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Northeast Appalachia production.

Southwest Appalachia

Southwest Appalachia represented 41% of our total 2019 net production and 62% of our total reserves as of December 31, 2019. In 2019, our reserves in Southwest Appalachia increased by 329 Bcfe, which included net additions of 333 Bcfe and net upward performance revisions of 975 Bcfe, partially offset by net downward price revisions of 660 Bcfe and production of 319 Bcfe. As of December 31, 2019, we had approximately 287,693 net acres in Southwest Appalachia and had a total of 505 wells on production that we operated. Below is a summary of Southwest Appalachia's operating results for the latest three years:

	For the years ended December 31,		
	2019	2018	2017
Acreage			
Net undeveloped acres	205,222 ⁽¹⁾	220,331	219,709
Net developed acres	82,471	77,114	70,582
Total net acres	287,693	297,445	290,291
Net Production			
Natural gas (Bcf)	150	105	85
Oil (MBbls)	4,673	3,355	2,228
NGL (MBbls)	23,611	19,679	14,193
Total production (Bcfe) ⁽²⁾	319	243	183
Reserves			
Reserves (Bcfe)	7,883	7,554	6,962
Locations:			
Proved developed producing	496	423	364
Proved developed non-producing	48	45	37
Proved undeveloped	376	488	559
Total locations	920	956	960
Gross Operated Well Count Summary			
Drilled	66	63	53
Completed	72	63	50
Wells to sales	69	76	57
Capital Investments (in millions)			
Drilling and completions, including workovers	\$ 516	\$ 502	\$ 353
Acquisition and leasehold	42	37	59
Seismic and other	3	4	4
Capitalized interest and expense	149	148	131
Total capital investments ⁽³⁾	\$ 710	\$ 691	\$ 547
Average completed well cost (in millions) ⁽⁴⁾⁽⁵⁾	\$ 8.9	\$ 9.2	\$ 7.4
Average lateral length (feet) ⁽⁴⁾⁽⁵⁾	10,642	7,267	7,451

(1) Our undeveloped acreage position as of December 31, 2019 had an average royalty interest of 14%.

(2) Approximately 317 Bcfe, 240 Bcfe and 179 Bcfe for the years ended December 31, 2019, 2018 and 2017, respectively, were produced from the Marcellus Shale formation.

(3) Excludes \$35 million, \$60 million and \$37 million for the years ended December 31, 2019, 2018 and 2017, respectively, related to our water infrastructure project.

(4) 2018 and 2017 include only wells drilled by the Company.

(5) Average completed well cost and average lateral length for the year ended December 31, 2019 include both Marcellus wells and Upper Devonian wells. The years ended December 31, 2018 and 2017 include Marcellus wells only and exclude three Upper Devonian wells in 2018 and one Utica well in 2017.

For 2019 as compared to 2018:

- Our average completed well cost per foot decreased primarily due to increased lateral lengths, operational execution and savings from vertical integration, water systems and direct-sourcing sand.

Our ability to bring our Southwest Appalachia production to market will depend on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to “Marketing” within Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Southwest Appalachia production.

Fayetteville Shale

On August 30, 2018, we entered into an agreement to effect the Fayetteville Shale sale for \$1,865 million, subject to customary adjustments. In early December 2018, we completed the Fayetteville Shale sale, resulting in net proceeds of \$1,650 million, following adjustments due primarily to the net cash flows from the economic effective date of July 1, 2018, to the closing date.

Production in the Fayetteville Shale totaled 243 Bcf for the year ended December 31, 2018, which represented 26% of our total 2018 net production. In 2018, we invested \$33 million in the Fayetteville Shale.

Other

Excluding 2,518,519 acres in New Brunswick, Canada, which have been subject to a government-imposed drilling moratorium since 2015, we held 27,334 net undeveloped acres for the potential development of new resources as of December 31, 2019 in areas outside of Appalachia. This compares to 153,159 net undeveloped acres held at year-end 2018 and 369,236 net undeveloped acres held at year-end 2017, excluding the New Brunswick acreage.

We limited our activities in areas beyond our assets in Appalachia during 2019, 2018 and 2017 as a result of the commodity price environment as we focused our capital allocation on these more economically competitive plays. There can be no assurance that any prospects outside of our development plays will result in viable projects or that we will not abandon our initial investments.

New Brunswick, Canada. We currently hold exclusive licenses to search and conduct an exploration program covering 2,518,519 net acres in New Brunswick. In 2015, the provincial government in New Brunswick imposed a moratorium on hydraulic fracturing until it is satisfied with a list of conditions. In response to this moratorium, the Company requested and was granted an extension of its licenses to March 2021. In May 2016, the provincial government announced that the moratorium would continue indefinitely. Unless and until the moratorium is lifted, we will not be able to develop these assets. Given this development, we fully impaired our investment in New Brunswick in 2016.

Acquisitions and Divestitures

On August 30, 2018, we entered into an agreement to effect the Fayetteville Shale sale for \$1,865 million, subject to customary adjustments. In early December 2018, we completed the Fayetteville Shale sale, receiving \$1,650 million in net proceeds after adjustments to the purchase price of \$215 million primarily due to the net cash flows from the economic effective date of July 1, 2018 to the closing date.

During 2019, we sold non-core acreage for \$38 million. There was no production or proved reserves associated with this acreage.

Capital Investments

(in millions)

E&P Capital Investments by Type

	For the years ended December 31,		
	2019	2018	2017
Drilling and completions, including workovers	\$ 838	\$ 895	\$ 878
Acquisition and leasehold	55	51	86
Seismic expenditures	3	4	7
Water infrastructure project	35	60	37
Drilling rigs, sand facility, and other	21	15	28
Capitalized interest and other expenses	186	206	212
Total E&P capital investments	<u>\$ 1,138</u>	<u>\$ 1,231</u>	<u>\$ 1,248</u>

E&P Capital Investments by Area

Northeast Appalachia	\$ 365	\$ 422	\$ 489
Southwest Appalachia	710	691	547
Fayetteville Shale ⁽¹⁾	—	33	114
Other ⁽²⁾	63	85	98
Total E&P capital investments	<u>\$ 1,138</u>	<u>\$ 1,231</u>	<u>\$ 1,248</u>

(1) The Fayetteville Shale E&P assets and associated reserves were divested in December 2018.

(2) Includes \$35 million, \$60 million and \$37 million for the years ended December 31, 2019, 2018 and 2017 related to our water infrastructure project.

- The decreases in 2019 and 2018 E&P capital investing, as compared to their respective prior years, resulted from our commitment to invest within our cash flows from operations, which are heavily dependent on commodity prices, supplemented by the remaining proceeds from the Fayetteville Shale sale.
- In 2019, we drilled 105 wells (93 of which were spud in 2019), completed 116 wells, placed 113 wells to sales and had 52 wells in progress at year-end.
- Of the 52 wells in progress at year-end, 28 and 24 were located in Northeast Appalachia and Southwest Appalachia, respectively.

We refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Investing” within Item 7 of Part II of this Annual Report for additional discussion of the factors that could impact our planned capital investments in 2020.

Sales, Delivery Commitments and Customers

Sales. The following tables present historical information about our production volumes for natural gas, oil and NGLs and our average realized natural gas, oil and NGL sales prices:

	For the years ended December 31,		
	2019	2018	2017
Average net daily production (MMcfe/day)	2,133	2,591	2,456
Production:			
Natural gas (Bcf)	609	807	797
Oil (MBbls)	4,696	3,407	2,327
NGLs (MBbls)	23,620	19,706	14,245
Total production (Bcfe)	<u>778</u>	<u>946</u>	<u>897</u>

- Production volumes for the year ended December 31, 2018 included 243 Bcf of production related to our operations in the Fayetteville Shale which was sold in December 2018. Excluding this amount, production volumes increased 75 Bcfe for the year ended December 31, 2019 due to the increase in production from Southwest Appalachia.
- The increase in production in 2018 resulted primarily from a 64 Bcf increase in net production from our Northeast Appalachia properties and a 60 Bcfe increase in net production from our Southwest Appalachia properties, partially offset by a 73 Bcf decrease in net production from our Fayetteville Shale properties, which were divested in December 2018.

Average Realized Prices

	For the years ended December 31,		
	2019	2018	2017
Natural Gas Price:			
NYMEX Henry Hub Price <i>(\$/MMBtu)</i> ⁽¹⁾	\$ 2.63	\$ 3.09	\$ 3.11
Discount to NYMEX ⁽²⁾	(0.65)	(0.64)	(0.88)
Average realized gas price, excluding derivatives <i>(\$/Mcf)</i>	\$ 1.98	\$ 2.45	\$ 2.23
Loss on settled financial basis derivatives <i>(\$/Mcf)</i>	—	(0.04)	(0.01)
Gain (loss) on settled commodity derivatives <i>(\$/Mcf)</i>	0.20	(0.06)	(0.03)
Average realized gas price, including derivatives <i>(\$/Mcf)</i>	\$ 2.18	\$ 2.35	\$ 2.19
Oil Price:			
WTI oil price <i>(\$/Bbl)</i>	\$ 57.03	\$ 64.77	\$ 50.96
Discount to WTI	(10.13)	(7.98)	(7.84)
Average realized oil price, excluding derivatives <i>(\$/Bbl)</i>	\$ 46.90	\$ 56.79	\$ 43.12
Gain (loss) on settled derivatives <i>(\$/Bbl)</i>	2.66	(0.72)	—
Average realized oil price, including derivatives <i>(\$/Bbl)</i>	\$ 49.56	\$ 56.07	\$ 43.12
NGL Price:			
Average realized NGL price, excluding derivatives <i>(\$/Bbl)</i>	\$ 11.59	\$ 17.91	\$ 14.46
Gain (loss) on settled derivatives <i>(\$/Bbl)</i>	2.05	(0.68)	0.02
Average realized NGL price, including derivatives <i>(\$/Bbl)</i>	\$ 13.64	\$ 17.23	\$ 14.48
Percentage of WTI, excluding derivatives	20 %	28 %	28 %
Total Weighted Average Realized Price:			
Excluding derivatives <i>(\$/Mcfe)</i>	\$ 2.18	\$ 2.66	\$ 2.32
Including derivatives <i>(\$/Mcfe)</i>	\$ 2.42	\$ 2.57	\$ 2.29

(1) Based on last day settlement prices from monthly futures contracts.

(2) This discount includes a basis differential, a heating content adjustment, physical basis sales, third-party transportation charges and fuel charges, and excludes financial basis hedges.

Sales of natural gas, oil and NGL production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for these commodities, including changes that may be induced by the effects of weather on demand for our production. We regularly enter into various derivative and other financial arrangements with respect to a portion of our projected production to support certain desired levels of cash flow and to minimize the impact of price fluctuations. We limit derivative agreements to counterparties with appropriate credit standings, and our policies prohibit speculation.

As of December 31, 2019, we had the following commodity price derivatives in place on our targeted future production:

	For the years ended December 31,		
	2020	2021	2022
Natural gas <i>(Bcf)</i>	496	260	31
Oil <i>(MBbls)</i>	5,402	3,029	438
Ethane <i>(MBbls)</i>	7,520	2,410	—
Propane <i>(MBbls)</i>	5,112	2,460	—

As of February 25, 2020, we had the following commodity price derivatives in place on our targeted 2020 and future production:

	For the years ended December 31,		
	2020	2021	2022
Natural gas <i>(Bcf)</i>	546	311	62
Oil <i>(MBbls)</i>	5,902	3,773	1,104
Ethane <i>(MBbls)</i>	8,099	2,725	—
Propane <i>(MBbls)</i>	5,112	2,460	—

We intend to use derivatives to limit the impact of price volatility on a large portion of expected future production volumes to ensure certain desired levels of cash flow. We refer you to Item 7A of Part II of this Annual Report, “Quantitative and Qualitative Disclosures about Market Risk,” for further information regarding our derivatives and risk management as of December 31, 2019.

During 2019, the average price we received for our natural gas production, excluding the impact of derivatives and including the cost of transportation, was approximately \$0.65 per Mcf lower than average New York Mercantile Exchange, or NYMEX, prices. Differences between NYMEX and price realized (basis differentials) are due primarily to locational differences and transportation cost.

As of December 31, 2019, we have entered into physical sales arrangements to limit the impact of basis volatility on approximately 165 Bcf and 50 Bcf of our 2020 and 2021 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately (\$0.04) per MMBtu and (\$0.28) per MMBtu for 2020 and 2021, respectively.

We have also entered into financial basis swaps for approximately 198 Bcf, 86 Bcf and 45 Bcf of our 2020, 2021 and 2022 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately (\$0.31) per MMBtu, \$0.04 per MMBtu and (\$0.50) per MMBtu for 2020, 2021 and 2022, respectively, as of December 31, 2019.

We refer you to Note 6 to the consolidated financial statements included in this Annual Report for additional discussion about our derivatives and risk management activities.

Delivery Commitments. As of December 31, 2019, we had natural gas delivery commitments of 315 Bcf in 2020 and 83 Bcf in 2021 under existing agreements. These amounts are well below our expected 2020 natural gas production from Northeast Appalachia and Southwest Appalachia and expected 2021 production from our available reserves, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our delivery commitments other than those discussed in Item 1A “Risk Factors” of Part I of this Annual Report. We expect to be able to fulfill all of our short-term and long-term delivery commitments to provide natural gas from our own production of available reserves; however, if we are unable to do so, we may have to purchase natural gas at market to fulfill our obligations.

Customers. Our E&P production is marketed primarily by our Marketing segment. Our customers include major energy companies, utilities and industrial purchasers of natural gas. During the year ended December 31, 2019, no single third-party purchaser accounted for 10% or more of our consolidated revenues. For the years ended December 31, 2018 and 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% and 10.3%, respectively, of total natural gas, oil and NGL sales. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production.

Competition

All phases of the natural gas and oil industry are highly competitive. We compete in the acquisition and disposition of properties, the search for and development of reserves, the production and marketing of natural gas, oil and NGLs, and the securing of labor, services and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies and individual producers. Many of these competitors have financial and other resources that substantially exceed those available to us. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. We also face competition in accessing pipeline and other services to transport our product to market. Likewise, there are substitutes for the commodities we produce, such as other fuels for power generation, heating and transportation, and those markets in effect compete with us.

We cannot predict whether and to what extent any regulatory changes initiated by the Federal Energy Regulatory Commission, or the FERC, or any other new energy legislation or regulations will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas production is sold. Similarly, we cannot predict whether legal constraints that have hindered the development of new transportation infrastructure, particularly in the northeastern United States, will continue. However, we do not believe that we will be disproportionately affected as compared to other natural gas and oil producers and marketers by any action taken by the FERC or any other legislative or regulatory body or the status of the development of transportation facilities.

Regulation

Producing natural gas, oil and NGL resources and transporting and selling production historically have been heavily regulated. For example, state governments regulate the location of wells and establish the minimum size for spacing units. Permits typically are required before drilling. State and local government zoning and land use regulations may also limit the locations for drilling and production. Similar regulations can also affect the location, construction and operation of gathering

and other pipelines needed to transport production to market. In addition, various suppliers of goods and services may require licensing.

Currently in the United States, the price at which natural gas, oil or NGLs may be sold is not regulated. Congress has imposed price regulation from time to time, and there can be no assurance that the current, less stringent regulatory approach will continue. In 2015, the federal government repealed a 40-year ban on the export of crude oil. The export of natural gas continues to require federal permits. Broader freedom to export could lead to higher prices. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) and the rules that the U.S. Commodity Futures Trading Commission, (the “CFTC”), the SEC, and certain other regulators have issued thereunder regulate certain swaps, futures and options contracts in the major energy markets, including for natural gas, oil and NGLs

Producing and transporting natural gas, oil and NGLs is also subject to extensive environmental regulation. We refer you to “Other – Environmental Regulation” in Item 1 of Part 1 of this Annual Report and the risk factor “We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities” in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Marketing

We engage in marketing and, prior to the Fayetteville Shale sale, natural gas gathering activities which primarily support our E&P operations. We generate revenue through the marketing of natural gas, oil and NGLs and, historically, from gathering fees associated with in-field gathering activities. The Fayetteville Shale sale, which closed in December 2018, included all midstream gathering assets associated with our previous operations in Arkansas, which comprised the vast majority of our midstream gathering business.

	For the years ended December 31,		
	2019	2018	2017
Marketing revenues <i>(in millions)</i>	\$ 2,849	\$ 3,497	\$ 2,867
Gathering revenues <i>(in millions)</i>	—	248	331
Other revenues <i>(in millions)</i>	1	—	—
Total operating revenues <i>(in millions)</i>	\$ 2,850	\$ 3,745	\$ 3,198
Operating income (loss) <i>(in millions)</i>	\$ (13)	\$ 4	\$ 183
Cash flows from operations <i>(in millions)</i>	\$ 127	\$ 70	\$ 208
Capital investments – gathering <i>(in millions)</i>	\$ —	\$ 9	\$ 32
Natural gas gathered from the Fayetteville Shale <i>(Bcf)</i>			
Operated wells <i>(Bcf)</i>	—	355	463
Third-party operated wells <i>(Bcf)</i>	—	26	35
Total volumes gathered in the Fayetteville Shale <i>(Bcf)</i>	—	381	498
Volumes marketed <i>(Bcfe)</i>	1,101	1,163	1,067
Percent natural gas marketed from affiliated E&P operations	79 %	93 %	96 %
Percent oil and NGLs marketed from affiliated E&P operations	61 %	69 %	63 %

- Operating income for the year ended December 31, 2018 included a \$7 million loss related to our gathering operations in the Fayetteville Shale, which we sold in December 2018. Excluding this amount, operating income decreased \$24 million for the year ended December 31, 2019, compared to 2018, primarily due to \$26 million decrease in marketing margin.
- Operating income for the year ended December 31, 2018 included \$155 million of non-cash impairments, primarily related to our midstream gathering assets divested as part of the Fayetteville Shale sale along with certain other non-core gathering assets, and \$2 million of restructuring charges. Excluding these charges, operating income from our Marketing segment decreased \$22 million in 2018 compared to 2017, primarily due to an \$83 million decrease in gas gathering revenues and a \$1 million decrease in marketing margin, partially offset by a \$33 million decrease in operating costs and expenses and a \$29 million increase in gain on sale of assets, net.

- Marketing revenues decreased in 2019, compared to 2018, primarily due to a decrease in the price received for volumes marketed and a decrease in volumes marketed. We had no significant gathering revenues for the year ended December 31, 2019 as a result of the sale of our midstream gathering operations in the Fayetteville Shale in December 2018.
- Revenues increased in 2018, compared to 2017, primarily due to an increase in the price received for volumes marketed which was partially offset by a decrease in volumes gathered.
- Cash flow from operations generated by our Marketing segment increased in 2019, compared to 2018, as an \$895 million decrease in operating revenues, partially offset by a \$726 million decrease in cash operating costs and expenses, was more than offset by a \$226 million increase primarily related to timing differences of payables and receivables between the respective periods.
- The decrease in cash flow from operations in 2018, compared to 2017, was primarily due to an \$83 million decrease in gas gathering revenues, partially offset by a \$12 million decrease in cash operating costs and expenses, a \$64 million decrease related to timing differences of payables and receivables between the respective periods and a \$3 million decrease in Other Income (Loss), Net.

Gas Gathering

In December 2018, we sold our midstream gathering operations in Arkansas as part of the Fayetteville Shale sale. Our remaining interests in gathering systems are not expected to generate material revenues.

Marketing

We attempt to capture opportunities related to the marketing and transportation of natural gas, oil and NGLs primarily involving the marketing of our own equity production and that of royalty owners in our wells. Additionally, we manage portfolio and locational, or basis, risk, acquire transportation rights on third-party pipelines and, in limited circumstances, purchase third-party natural gas to fulfill commitments specific to a geographic location.

Northeast Appalachia. Our transportation portfolio in Northeast Appalachia is highly diversified and allows us to access premium city-gate markets as well as to deliver natural gas from the Appalachian basin area to the southeast United States. The capacity agreements contain multiple extension and reduction options that allow us to right-size our transportation portfolio as needed for our production or to capture future market opportunities. The table below details our firm transportation, firm sales and total takeaway capacity over the next three years as of February 25, 2020:

(MMBtu/d)	For the year ended December 31,		
	2020	2021	2022
Firm transportation	1,302,548	1,186,840	1,101,881
Firm sales	201,792	64,167	29,167
Total firm takeaway – Northeast Appalachia	1,504,340	1,251,007	1,131,048

Southwest Appalachia. Our transportation portfolio for all products in Southwest Appalachia allows us to capitalize on strengthening markets and provides a path for production growth. Agreements with ET Rover Pipeline LLC and Columbia Pipeline Group, Inc.'s Mountaineer Xpress and Gulf Xpress pipelines allow us to access high-demand markets along the Gulf Coast while also capturing materially improving in-basin pricing. In addition to our natural gas transportation, we have ethane take-away capacity that provides direct access to Mont Belvieu pricing. The table below details our natural gas firm transportation, firm sales and total takeaway capacity over the next three years as of February 25, 2020:

(MMBtu/d)	For the year ended December 31,		
	2020	2021	2022
Firm transportation	832,140	960,890	932,340
Firm sales	—	7,500	45,000
Total firm takeaway – Southwest Appalachia	832,140	968,390	977,340

Demand Charges

As of December 31, 2019, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately \$8.5 billion, \$1.1 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. We also have guarantee obligations of up to \$293 million of that amount. In February 2020, we were notified that the proposed Constitution pipeline project was cancelled and that we were released from a firm transportation agreement with its sponsor. As of December 31, 2019, we had contractual commitments totaling \$512 million over the next seventeen years related to the

Constitution pipeline project that are reflected in the \$8.5 billion of firm transportation obligations discussed above that were pending regulatory approval and/or construction.

As part of the Fayetteville Shale sale, we retained certain contractual commitments related to firm transportation, with the buyer obligated to pay the transportation provider directly for these charges. As of December 31, 2019, approximately \$108 million of these contractual commitments remain of which we will reimburse the buyer for certain of these potential obligations up to approximately \$58 million through 2020 depending on the buyer's actual use. We have recorded a \$46 million liability, which is the present value of the estimated future payments. The buyer has also assumed future asset retirement obligations related to the operations sold.

In the first quarter of 2019, we agreed to purchase firm transportation with pipelines in Appalachia starting in 2021 and running through 2032 totaling \$357 million in total contractual commitments, of which the seller has agreed to reimburse us for \$133 million.

We refer you to Note 10 to the consolidated financial statements included in this Annual Report for further details on our demand charges and the risk factor "We have made significant investments in oilfield services businesses, including our drilling rigs, water infrastructure and pressure pumping equipment, to lower costs and secure inputs for our operations and transportation for our production. If our development and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers" in Item 1A of Part I of this Annual Report.

Competition

Our marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are other producers and affiliates of companies with extensive pipeline systems that are used for transportation from producers to end users. Other factors affecting competition are the cost and availability of alternative fuels, the level of consumer demand and the cost of and proximity to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with customers.

Customers

Our marketing customers include major energy companies, utilities and industrial purchasers of natural gas. During the year ended December 31, 2019, no single third-party purchaser accounted for 10% or more of our consolidated revenues. For the years ended December 31, 2018 and 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% and 10.3%, respectively, of total natural gas, oil and NGL sales. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production.

Regulation

The transportation of natural gas, oil and NGLs is heavily regulated. Interstate pipelines must obtain authorization from the FERC to operate in interstate commerce, and state governments typically must authorize the construction of pipelines for intrastate service. The FERC currently allows interstate pipelines to adopt market-based rates; however, in the past the FERC has regulated pipeline tariffs and could do so again in the future. State tariff regulations vary. Currently, all pipelines we own are intrastate and immaterial to our operations.

State and local permitting, zoning and land use regulations can affect the location, construction and operation of gathering and other pipelines needed to transport production to market, and the lack of new pipeline capacity can limit our ability to reach relevant markets for the sale of the commodities we produce.

The transportation of natural gas and oil is also subject to extensive environmental regulation. We refer you to "Other – Environmental Regulation" in Item 1 of Part I of this Annual Report and the risk factor "We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities" in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Other

We currently have no significant business activity outside of our E&P and Marketing segments.

Environmental Regulation

General. Our operations are subject to environmental regulation in the jurisdictions in which we operate. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements to drill or operate wells, and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the prevention and cleanup of pollutants and other matters. We maintain insurance for clean-up costs in limited instances arising out of sudden and accidental events, but otherwise we may not be fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Certain laws and legal principles can make us liable for environmental damage to properties we previously owned, and although we generally require purchasers to assume that liability, there is no assurance that they will have sufficient funds should a liability arise. Changes in environmental laws and regulations occur frequently, and any changes may result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements. We do not expect continued compliance with existing requirements to have a material adverse impact on us, but there can be no assurance that this will continue in the future. We refer you to “Other – Environmental Regulation” in Item 1 of Part I of this Annual Report and the risk factor “We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities” in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

The following is a summary of the more significant existing environmental and worker health and safety laws and regulations to which we are subject.

Generation and Disposal of Wastes. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, also known as CERCLA or the “Superfund law,” imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that 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 a site where the release occurred, as well as persons that transported or disposed, or arranged for the transportation or disposal of, the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and 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.

The Resource Conservation and Recovery Act, as amended, or RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste “drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil, natural gas or geothermal energy.” However, legislative and regulatory initiatives have been considered from time to time that would reclassify certain natural gas and oil exploration and production wastes as “hazardous wastes,” which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such measures were to be enacted, it could have a significant impact on our operating costs. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Clean Water Act, as amended, or CWA, and analogous state laws, impose restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into regulated waters. Permits must be obtained to discharge pollutants to regulated waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

The Oil Pollution Act, as amended, or OPA, and regulations promulgated thereunder impose a variety of requirements on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills into regulated waters. A “responsible party” includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. Although liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety,

construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Although oil accounted for only 4% of our total production in 2019 and 2% in 2018 and 2017, we expect this percentage to increase as we continue to develop our Southwest Appalachia assets.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration for and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us and/or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. Under CERCLA, the CWA, RCRA and analogous state laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Air Emissions. The Clean Air Act, as amended, restricts emissions into the atmosphere. Various activities in our operations, such as drilling, pumping and the use of vehicles, can release matter subject to regulation. We must obtain permits, typically from local authorities, to conduct various activities. Federal and state governmental agencies are looking into the issues associated with methane and other emissions from oil and natural gas activities, and further regulation could increase our costs or restrict our ability to produce. Although methane emissions are not currently regulated at the federal level, we are required to report emissions of various greenhouse gases, including methane.

Threatened and Endangered Species. The Endangered Species Act and comparable state laws protect species threatened with possible extinction. Protection of threatened and endangered species may have the effect of prohibiting or delaying us from obtaining drilling and other permits and may include restrictions on road building and other activities in areas containing the affected species or their habitats. Based on the species that have been identified to date, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our operations at this time.

Hydraulic Fracturing. We utilize hydraulic fracturing in drilling wells as a means of maximizing their productivity. It is an essential and common practice in the oil and gas industry used to stimulate the production of oil, natural gas, and associated liquids from dense and deep rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore.

In the past several years, there has been an increased focus on environmental aspects of hydraulic fracturing practice, both in the United States and abroad. In the United States, hydraulic fracturing is typically regulated by state oil and natural gas commissions, but federal agencies have started to assert regulatory authority over certain aspects of the process. For example, the Environmental Protection Agency, or EPA, issued final rules effective as of October 15, 2012 that subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS programs. In May 2016, the EPA finalized additional regulations to control methane and volatile organic compound (“VOC”) emissions from certain oil and gas equipment and operations. In September 2018, the EPA issued proposed revisions to those regulations, which, if finalized, would reduce certain obligations thereunder. Later, in August 2019, the EPA proposed two options for rescinding the regulations. Under the EPA’s preferred alternative, the agency would rescind the methane limits for new, reconstructed and modified oil and natural gas production sources while leaving in place the general emission limits for VOCs, and relieve the EPA of its obligation to develop guidelines for methane emissions from existing sources. In addition, the proposal would remove from the oil and natural gas category the natural gas transmission and storage segment. The other proposed alternative would rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from that source category (and still requiring control of VOCs in general). The EPA also finalized pretreatment standards that would prohibit the indirect discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned treatment works. Based on our current operations and practices, management believes such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management’s view may change in the future.

In addition, there are certain governmental reviews either underway or proposed that focus on environmental aspects of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released its final report regarding the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances such as 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. The results of these studies could lead federal and state governments and agencies to develop and implement additional regulations.

Although the current federal administration has relaxed many regulations adopted in the latter part of the prior administration, some states in which we operate have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

Increased regulation and attention given to the hydraulic fracturing process has led to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. In addition, various officials and candidates at the federal, state and local levels, including some presidential candidates, have proposed banning hydraulic fracturing altogether. We refer you to the risk factor “We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities” in Item 1A of Part I of this Annual Report.

In addition, concerns have been raised about the potential for seismic activity to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others. We utilize third parties to dispose of waste water associated with our operations. These third parties may operate injection wells and may be subject to regulatory restrictions relating to seismicity.

Greenhouse Gas Emissions. In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet “best available control technology” standards that will be established on a case-by-case basis. One of our subsidiaries operates compressor stations, which are facilities that are required to adhere to the PSD or Title V permit requirements. EPA rulemakings related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Although Congress from time to time has considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or install new equipment to reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material

adverse effect on our business, financial condition, results of operations and cash flows. At the same time, new laws and regulations are prompting power producers to shift from coal to natural gas, which is increasing demand.

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions (the “Paris Agreement”). The Paris Agreement entered into effect in November 2016 after more than 70 nations, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. In June 2017, President Trump announced that the United States intends to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or a separate agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement, and in November 2019 the United States initiated the year-long process of formally withdrawing, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse effect on our business.

Employee Health and Safety. Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Canada. Our activities in Canada have, to date, been limited to certain geological and geophysical activities and now are subject to a moratorium. If and when the moratorium ends and should we begin drilling and development activities in New Brunswick, we will be subject to federal, provincial and local environmental regulations.

Employees

As of December 31, 2019, we had 923 total employees, a decrease of 4% compared to year-end 2018. None of our employees were covered by a collective bargaining agreement at year-end 2019. We believe that our relationships with our employees are good. In February 2020, we notified employees of a workforce reduction plan as a result of a strategic realignment of our organizational structure. This reduction will be substantially complete by the end of the first quarter of 2020. Affected employees were offered a severance package, which included a one-time payment depending on length of service and, if applicable, the current value of a portion of unvested long-term incentive awards that were forfeited.

Executive Officers of the Registrant

The following table shows certain information as of February 25, 2020 about our executive officers, as defined in Rule 3b-7 of the Securities Exchange Act of 1934:

<u>Name</u>	<u>Age</u>	<u>Officer Position</u>
William J. Way	60	President and Chief Executive Officer
Julian M. Bott	57	Executive Vice President and Chief Financial Officer
Clayton A. Carrell	54	Executive Vice President and Chief Operating Officer
J. David Cecil	53	Executive Vice President Corporate Development
Jennifer N. McCauley	56	Senior Vice President – Administration
John C. Ale	65	Senior Vice President, General Counsel and Secretary
Jason Kurtz	49	Vice President – Marketing and Transportation

Mr. Way was appointed Chief Executive Officer in January 2016. Prior to that, he served as Chief Operating Officer since 2011, having also been appointed President in December 2014. Prior to joining the Company, he was Senior Vice President, Americas of BG Group plc with responsibility for E&P, Midstream and LNG operations in the United States, Trinidad and Tobago, Chile, Bolivia, Canada and Argentina since 2007.

Mr. Bott was appointed Executive Vice President and Chief Financial Officer in February 2018. Prior to that, he was Executive Vice President and Chief Financial Officer of SandRidge Energy, Inc. since 2015.

Mr. Carrell was appointed Executive Vice President and Chief Operating Officer in December 2017. Prior to joining the Company, he was Executive Vice President and Chief Operating Officer of EP Energy since 2012.

Mr. Cecil was appointed Executive Vice President Corporate Development in August 2017. Prior to joining the Company, he was Managing Director and Head of the North American E&P group of Lazard since 2012.

Ms. McCauley was appointed Senior Vice President – Administration in April 2016. Prior to that, she served as Senior Vice President – Human Resources since 2009.

Mr. Ale was appointed Senior Vice President, General Counsel and Secretary in November 2013. Prior to that, he was Vice President and General Counsel of Occidental Petroleum Corporation since April 2012. Prior to that, he was a partner with Skadden, Arps, Slate, Meagher & Flom LLP since 2002.

Mr. Kurtz was appointed Vice President of Marketing and Transportation in May 2011. Prior to that, he served in various marketing roles since joining the Company in May 1997.

There are no family relationships between any of the Company’s directors or executive officers.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below include indicated terms in this Annual Report. All natural gas reserves reported in this Annual Report are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit. All currency amounts are in U.S. dollars unless specified otherwise.

“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. For additional information, see the SEC’s definition in Rule 4-10(a) (1) of Regulation S-X, a link for which is available at the SEC’s website.

“Available reserves” Estimates of the amounts of natural gas, oil and NGLs which the registrant can produce from current proved developed reserves using presently installed equipment under existing economic and operating conditions and an estimate of amounts that others can deliver to the registrant under long-term contracts or agreements on a per-day, per-month, or per-year basis. For additional information, see the SEC’s definition in Item 1207(d) of Regulation S-K, a link for which is available at the SEC’s website.

“Basis differential” The difference in price for a commodity between a market index price and the price at a specified location.

“Bbl” One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

“Bcf” One billion cubic feet of natural gas.

“Bcfe” One billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of oil or natural gas liquids to six Mcf of natural gas.

“Btu” One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

“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. For additional information, see the SEC’s definition in Rule 4-10(a) (5) of Regulation S-X, a link for which is available at the SEC’s website.

“Developed oil and gas reserves” Developed oil and natural 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.

For additional information, see the SEC’s definition in Rule 4-10(a) (6) of Regulation S-X, a link for which is available at the SEC’s website.

“Development costs” Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing natural gas, oil and NGLs. 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.

For additional information, see the SEC's definition in Rule 4-10(a) (7) of Regulation S-X, a link for which is available at the SEC's website.

"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. For additional information, see the SEC's definition in Rule 4-10(a) (8) of Regulation S-X, a link for which is available at the SEC's website.

"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. For additional information, see the SEC's definition in Rule 4-10(a) (9) of Regulation S-X, a link for which is available at the SEC's website.

"E&P" Exploration for and production of natural gas, oil and NGLs.

"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. For additional information, see the SEC's definition in Rule 4-10(a) (10) of Regulation S-X, a link for which is available at the SEC's website.

"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. For additional information, see the SEC's definition in Rule 4-10(a) (11) of Regulation S-X, a link for which is available at the SEC's website.

"Exploitation" The development of a reservoir to extract its natural gas and/or oil.

"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. For additional information, see the SEC's definition in Rule 4-10(a) (13) of Regulation S-X, a link for which is available at the SEC's website.

"Field" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc. For additional information, see the SEC's definition in Rule 4-10(a) (15) of Regulation S-X, a link for which is available at the SEC's website.

"Gross well or acre" A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. For additional information, see the SEC's definition in Item 1208(c)(1) of Regulation S-K, a link for which is available at the SEC's website.

"Gross working interest" Gross working interest is the working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest.

"Henry Hub" A common market pricing point for natural gas in the United States, located in Louisiana.

“Hydraulic fracturing” A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

“Infill drilling” Drilling wells in between established producing wells to increase recovery of natural gas, oil and NGLs from a known reservoir.

“MBbls” One thousand barrels of oil or other liquid hydrocarbons.

“Mcf” One thousand cubic feet of natural gas.

“Mcf_e” One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

“MMBbls” One million barrels of oil or other liquid hydrocarbons.

“MMBtu” One million British thermal units (Btus).

“MMcf” One million cubic feet of natural gas.

“MMcf_e” One million cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

“Mont Belvieu” A pricing point for North American NGLs.

“Net acres” The sum, for any area, of the products for each tract of the acres in that tract multiplied by the working interest in that tract. For additional information, see the SEC’s definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC’s website.

“Net revenue interest” Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

“Net well” The sum, for all wells being discussed, of the working interests in those wells. For additional information, see the SEC’s definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC’s website.

“NGLs” Natural gas liquids (includes ethane, propane, butane, isobutane, pentane and pentanes plus).

“NYMEX” The New York Mercantile Exchange, on which spot and future contracts for natural gas and other commodities are traded.

“Operating interest” An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

“Overriding royalty interest” A fractional, undivided interest or right to production or revenues, free of costs, of a lessee with respect to an oil or natural gas well, that overrides a working interest.

“Play” A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

“Present Value Index” or “PVI” A measure that is computed for projects by dividing the dollars invested into the PV-10 resulting or expecting to result from the investment by the dollars invested.

“Pressure pumping spread” All of the equipment needed to carry out a hydraulic fracturing job.

“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. For additional information, see the SEC’s definition in Rule 4-10(a) (19) of Regulation S-X, a link for which is available at the SEC’s website.

“Producing property” A natural gas and oil property with existing production.

“Productive wells” Producing wells and wells mechanically capable of production. For additional information, see the SEC’s definition in Item 1208(c)(3) of Regulation S-K, a link for which is available at the SEC’s website.

“Proppant” Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

“Proved developed producing” Proved developed reserves that can be expected to be recovered from a reservoir that is currently producing through existing wells.

“Proved developed reserves” Proved natural gas, oil and NGLs that are also developed natural gas, oil and NGL reserves.

“Proved natural gas, oil and NGL reserves” Proved natural gas, oil and NGL reserves are those quantities of natural gas, oil and NGLs that, 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. Also referred to as “proved reserves.” For additional information, see the SEC’s definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC’s website.

“Proved reserves” See “proved natural gas, oil and NGL reserves.”

“Proved undeveloped reserves” or **“PUD”** Proved natural gas, oil and NGL reserves that are also undeveloped natural gas, oil and NGL reserves.

“PV-10” When used with respect to natural gas, oil and NGL 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 costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as “present value.” After-tax PV-10 is also referred to as “standardized measure” and is net of future income tax expense.

“Reserve life index” The quotient resulting from dividing total reserves by annual production and typically expressed in years.

“Reserve replacement ratio” The sum of the estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions (which may include or exclude reserve revisions of previous estimates) for a specified period of time divided by production for that same period of time.

“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. For additional information, see the SEC’s definition in Rule 4-10(a) (27) of Regulation S-X, a link for which is available at the SEC’s website.

“Royalty interest” An interest in a natural gas and oil property entitling the owner to a share of natural gas, oil or NGL production free of production costs.

“Tcfe” One trillion cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

“Unconventional play” A play in which the targeted reservoirs generally fall into one of three categories: tight sands, coal beds, or shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

“Undeveloped acreage” Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. For additional information, see the SEC’s definition in Item 1208(c)(4) of Regulation S-K, a link for which is available at the SEC’s website.

“Undeveloped natural gas, oil and NGL reserves” Undeveloped natural gas, oil and NGL 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. Also referred to as “undeveloped reserves.” For additional information, see the SEC’s definition in Rule 4-10(a) (31) of Regulation S-X, a link for which is available at the SEC’s website.

“Undeveloped reserves” See “undeveloped natural gas, oil and NGL reserves.”

“Wells to sales” Wells that have been placed on sales for the first time.

“Working interest” An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

“Workovers” Operations on a producing well to restore or increase production.

“WTI” West Texas Intermediate, the benchmark oil price in the United States.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

Natural gas, oil and NGL prices greatly affect our revenues and thus profits, liquidity, growth, ability to repay our debt and the value of our assets.

Our revenues, profitability, liquidity, growth, ability to repay our debt and the value of our assets greatly depend on prices for natural gas, oil and NGLs. The markets for these commodities are volatile, and we expect that volatility to continue. The prices of natural gas, oil and NGLs fluctuate in response to changes in supply and demand (global, regional and local), transportation costs, market uncertainty and other factors that are beyond our control. Short- and long-term prices are subject to a myriad of factors such as:

- overall demand, including the relative cost of competing sources of energy or fuel;
- overall supply, including costs of production;
- the availability, proximity and capacity of pipelines, other transportation facilities and gathering, processing and storage facilities;
- regional basis differentials;
- national and worldwide economic and political conditions;
- weather conditions and seasonal trends;
- government regulations, such as regulation of natural gas transportation and price controls;
- inventory levels; and
- market perceptions of future prices, whether due to the foregoing factors or others.

For example, in 2018 and 2019, the NYMEX settlement price for natural gas ranged from a low of \$2.14 per MMBtu in August 2019 to a high of \$4.72 per MMBtu in December 2018, and during this period our production was 85% and 78% natural gas, respectively. NGLs represent a growing part of our business, and in the same period prices for ethane and propane, our two principal NGL products, ranged from \$6.12 per Bbl in July 2019 to \$22.13 per Bbl in September 2018 and \$16.92 per Bbl in August 2019 to \$44.47 per Bbl in September 2018, respectively. Although we hedge a large portion of our production against changing prices, derivatives do not protect all our future volumes, may result in our forgoing profit opportunities if markets rise and, for NGLs, are not always available for substantial periods into the future. In 2019, we received \$180 million, net of amounts we paid, in settlement of hedging arrangements. Moreover, when market expectations of future prices fall, as they did in 2019, the prices at which we can hedge are lower, reducing future revenue.

Lower natural gas, oil and NGL prices directly reduce our revenues and thus our operating income and cash flow. Lower prices also reduce the projected profitability of further drilling and therefore are likely to reduce our drilling activity, which in turn means we will have fewer wells on production in the future. Lower prices also reduce the value of our assets, both by a direct reduction in what the production would be worth and by making some properties uneconomic, resulting in non-cash impairments to the recorded value of our reserves and non-cash charges to earnings. For example, in 2016, we reported non-cash impairment charges on our natural gas and oil properties totaling \$2.3 billion, primarily resulting from decreases in trailing 12-month average first-day-of-the-month natural gas prices throughout 2016, as compared to 2015, and the non-cash impairment of certain undeveloped leasehold interests. Given the fall in commodity prices in 2019 and early 2020 and assuming that commodity prices remain at January 2020 levels for the rest of the first quarter of 2020, we expect a non-cash impairment to our natural gas and oil properties in the first quarter of 2020 ranging from approximately \$400 million to \$600 million, net of tax.

Further non-cash impairments in future periods could occur if the trailing 12-month commodity prices decrease as compared to the average used in prior periods.

As of December 31, 2019, we had \$2.3 billion of debt outstanding, consisting principally of senior notes maturing in various increments from 2022 to 2027, and \$34 million of borrowings under our revolving credit facility, which matures in 2024. At current commodity price levels, our net cash flow from operations is substantially higher than our interest obligations under this debt, but significant drops in realized prices could affect our ability to pay our current obligations or refinance our debt as it becomes due.

Moreover, general industry conditions may make it difficult or costly to refinance increments of this debt as it matures. Although our indentures do not contain significant covenants restricting our operations and other activities, our bank credit agreements contain financial covenants with which we must comply. We refer you to the risk factor “Our current and future levels of indebtedness may adversely affect our results and limit our growth.” Our inability to pay our current obligations or refinance our debt as it becomes due could have a material and adverse effect on our company. The drop in prices since 2014 has reduced our revenues, profits and cash flow, caused us to record significant non-cash asset impairments and led us to reduce both our level of capital investing and our workforce, which has caused us to incur significant expenses relating to employee terminations. Further price decreases could have similar consequences. Similarly, a rise in prices to levels experienced before 2015 could significantly increase our revenues, profits and cash flow, which could be used to expand capital investments.

Significant capital investment is required to replace our reserves and conduct our business.

Our activities require substantial capital investment, not only to expand revenues but also because production from existing wells and thus revenues declines each year. We intend to fund our future capital investing through net cash flows from operations, net of changes in working capital, supplemented on occasion by funds earmarked from the net proceeds of significant transactions, such as the Fayetteville Shale sale, which in the meantime were used to reduce outstanding debt. Our ability to generate operating cash flow is subject to many of the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Future cash flows from operations are subject to a number of risks and variables, such as the level of production from existing wells, prices of natural gas, oil and NGLs, our success in developing and producing new reserves and the other risk factors discussed herein. If we are unable to fund capital investing, we could experience a further reduction in drilling new wells, acquiring new acreage and a loss of existing leased acreage, resulting in a decline in our cash flow from operations and natural gas, oil and NGL production and reserves.

If we are not able to replace reserves, our production levels and thus our revenues and profits may decline.

Production levels from existing wells decline over time, and drilling new wells requires an inventory of leases and other rights with reserves that have not yet been drilled. Our future success depends largely upon our ability to find, develop or acquire additional natural gas, oil and NGL reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, acquisition or exploration activities, our proved reserves and production will decline over time. Identifying and exploiting new reserves requires significant capital investment and successful drilling operations. Thus, our future natural gas, oil and NGL reserves and production, and therefore our revenues and profits, are highly dependent on our level of capital investments, our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

Our business depends on access to natural gas, oil and NGL transportation systems and facilities. Our commitments to assure availability of transportation could lead to substantial payments for capacity we do not use if production falls below projected levels.

The marketability of our natural gas, oil and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of transportation systems and facilities owned by third parties. For example, we can provide no assurance that sufficient transportation capacity will exist for expected production from Appalachia or that we will be able to obtain sufficient transportation capacity on economic terms. During the past few years, several planned pipelines intended to service production in the Northeast United States have experienced delays in their in-service dates due to regulatory delays and litigation.

Producers compete by lowering their sales prices, resulting in the locational differences from NYMEX pricing. Further, a lack of available capacity on transportation systems and facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these systems and facilities for an extended period of time could negatively affect our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

We have entered into gathering agreements in producing areas and multiple long-term firm transportation agreements relating to natural gas volumes from all our producing areas. As of December 31, 2019, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately \$8.5 billion. If our development programs fail to produce sufficient quantities of natural gas and ethane to fill the contracted capacity within expected timeframes, we would be required to pay demand or other charges for transportation on pipelines and gathering systems for capacity that we would not be fully utilizing. In those situations, which have occurred on a small scale at various times, we endeavor to sell or transfer that capacity to others or fill the excess capacity with production purchased from third parties. There can be no assurance that these measures will recoup the full cost of the unused transportation.

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

Actual or anticipated changes or downgrades in our credit ratings, including any announcement that our ratings are under review for a downgrade, could impact our ability to access debt markets in the future to refinance existing debt or obtain additional funds, affect the market value of our senior notes and increase our borrowing costs. Such ratings are limited in scope, and do not address all material risks relating to us, but rather reflect only the view of each rating agency of the likelihood we will be able to repay our debt at the time the rating is issued. An explanation of the significance of each rating may be obtained from the applicable rating agency. As of February 25, 2020, our long-term issuer ratings were Ba2 by Moody's, BB by Standard and Poor's and BB by Fitch Investor Services. There can be no assurance that such credit ratings will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency's judgment, circumstances so warrant.

Actual downgrades in our credit ratings may also impact our interest costs and liquidity. The interest rates under certain of our senior notes increases as credit ratings fall. Many of our existing commercial contracts contain, and future commercial contracts may contain, provisions permitting the counterparty to require increased security upon the occurrence of a downgrade in our credit rating. Providing additional security, such as posting letters of credit, could reduce our available cash or our liquidity under our revolving credit facility for other purposes. We had \$172 million of letters of credit outstanding at December 31, 2019. The amount of additional financial assurance would depend on the severity of the downgrade from the credit rating agencies, and a downgrade could result in a decrease in our liquidity.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging in the face of shifting market conditions, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our future growth rate.

We necessarily must consider future price and cost environments when deciding how much capital we are likely to have available from net cash flow and how best to allocate it. Our current philosophy is to generally operate within cash flow from operations net of changes in working capital, supplemented in 2019 and 2020 with earmarked proceeds from the sale of our Fayetteville Shale assets in December 2018, and to invest capital in a portfolio of projects that are projected to generate the highest combined PVI. Volatility in prices and potential errors in estimating costs, reserves or timing of production of the reserves can result in uneconomic projects or economic projects generating less than anticipated returns.

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

Approximately 9,399 and 35,924 net acres of our Northeast Appalachia and Southwest Appalachia acreage, respectively, will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Our ability to drill wells depends on a number of factors, including certain factors that are beyond our control, such as the ability to obtain permits on a timely basis or to compel landowners or lease holders on adjacent properties to cooperate. Further, we may not have sufficient capital to drill all the wells necessary to hold the acreage without increasing our debt levels, or given price projections at the time, drilling may not be projected to achieve a sufficient return or be judged to be the best use of our capital. To the extent we do not drill the wells, our rights to acreage can be lost.

Natural gas and oil drilling and producing and transportation operations can be hazardous and may expose us to liabilities.

Drilling and production operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of our prospects. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;

- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

For our properties that we do not operate, we depend on the operator for operational and regulatory compliance.

We rely on third parties to transport our production to markets. Their operations, and thus our ability to reach markets, are subject to all of the risks and operational hazards inherent in transporting natural gas and ethane and natural gas compression, including:

- damages to pipelines, facilities and surrounding properties caused by third parties, severe weather, natural disasters, including hurricanes, and acts of terrorism;
- maintenance, repairs, mechanical or structural failures;
- damages to, loss of availability of and delays in gaining access to interconnecting third-party pipelines;
- disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack; and
- leaks of natural gas or ethane as a result of the malfunction of equipment or facilities.

A material event such as those described above could expose us to liabilities, monetary penalties or interruptions in our business operations. Although we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

Our current and future levels of indebtedness may adversely affect our results and limit our growth.

At December 31, 2019, we had long-term indebtedness of \$2.3 billion. The terms of the indentures governing our outstanding senior notes, our credit facilities, and the lease agreements relating to our drilling rigs, other equipment and headquarters building, which we collectively refer to as our “financing agreements,” impose restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, which may include, without limitation, one or more of the following:

- incurring additional debt;
- redeeming stock or redeeming certain debt;
- making certain investments;
- creating liens on our assets; and
- selling assets.

The revolving credit facility we entered into in April 2018, as amended (our “revolving credit facility”), contains customary representations, warranties and covenants including, among others, the following covenants:

- a prohibition against incurring debt, subject to permitted exceptions;
- a restriction on creating liens on assets, subject to permitted exceptions;
- restrictions on mergers and asset dispositions;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business; and

- maintenance of the following financial covenants, commencing with the fiscal quarter ended June 30, 2018:
 1. Minimum current ratio of no less than 1.00 to 1.00, whereby current ratio is defined as the Company's consolidated current assets (including unused commitments under the credit agreement, but excluding non-cash derivative assets) to consolidated current liabilities (excluding non-cash derivative obligations and current maturities of long-term debt).
 2. Maximum total net leverage ratio of no greater than (i) with respect to each fiscal quarter ending during the period from June 30, 2018 through March 31, 2019, 4.50 to 1.00, (ii) with respect to each fiscal quarter ending during the period from June 30, 2019 through March 31, 2020, 4.25 to 1.00, and (iii) with respect to each fiscal quarter ending on or after June 30, 2020, 4.00 to 1.00. Total net leverage ratio is defined as total debt less cash on hand (up to the lesser of 10% of credit limit or \$150 million) divided by consolidated EBITDAX for the last four consecutive quarters. EBITDAX, as defined in our revolving credit facility, excludes the effects of interest expense, depreciation, depletion and amortization, income tax, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs.

As of December 31, 2019, we were in compliance with all of the covenants of our revolving credit facility in all material respects. Our ability to comply with these financial covenants depends in part on the success of our development program and upon factors beyond our control, such as the market prices for natural gas, oil and NGLs.

Our level of indebtedness and off-balance sheet obligations, and the covenants contained in our financing agreements, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments, thereby reducing the availability of cash flow for working capital, capital investing and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital investing, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Any significant reduction in the borrowing base under our revolving credit facility may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

The amount we may borrow under our revolving credit facility is capped at the lower of the total of our bank commitments and a "borrowing base" determined from time to time by the lenders based on our reserves, market conditions and other factors. As of December 31, 2019, the borrowing base was \$2.1 billion, which was most recently reaffirmed as of October 8, 2019 and is above the total current commitments of \$2.0 billion. The borrowing base is subject to scheduled semiannual and other elective collateral borrowing base redeterminations based on our natural gas, oil and NGL reserves and other factors. As of December 31, 2019, we had \$34 million of outstanding borrowings under our revolving credit facility, and we expect to borrow under that facility in the future. As of December 31, 2019, we had \$172 million of letters of credit issued under the credit facility and unused borrowing capacity was approximately \$1.8 billion. Any significant reduction in our borrowing base as a result of borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination or other reasons, we would be required to repay the excess within a brief period. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Our ability to comply with the covenants and other restrictions in our financing agreements may be affected by events beyond our control, including prevailing economic and financial conditions.

Failure to comply with the covenants and other restrictions could lead to an event of default and the acceleration of our obligations under our senior notes, credit facilities or other financing agreements, and in the case of the lease agreements for drilling rigs, compressors and pressure pumping equipment, loss of use of the equipment. In particular, the occurrence of risks identified elsewhere in this section, such as declines in commodity prices, increases in basis differentials and inability to access markets, could reduce our profits and thus the cash we have to fulfill our financial obligations. If we are unable to satisfy our

obligations with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

We have made significant investments in oilfield service businesses, including our drilling rigs, water infrastructure and pressure pumping equipment, to lower costs and secure inputs for our operations and transportation for our production. If our development and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers.

We also have made investments to meet certain of our field services' needs, including establishing our own drilling rig operation, water transportation system in Southwest Appalachia and pressure pumping capability. If our level of operations is reduced for a long period, we may not be able to recover these investments. Further, our presence in these service and supply sectors, including competing with them for qualified personnel and supplies, may have an adverse effect on our relationships with our existing third-party service and resource providers or our ability to secure these services and resources from other providers.

Our business depends on the availability of water and the ability to dispose of water. Limitations or restrictions on our ability to obtain or dispose of water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water, or to dispose of or recycle water after use, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Moreover, the introduction of new environmental initiatives and regulations related to water acquisition or waste water disposal, including produced water, drilling fluids and other wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize hydraulic fracturing or waste water injection control wells.

In addition, concerns have been raised about the potential for seismic activity to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others. We utilize third parties to dispose of waste water associated with our operations. These third parties may operate injection wells and may be subject to regulatory restrictions relating to seismicity.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of water necessary for hydraulic fracturing of wells or the disposal of water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our producing properties are concentrated in the Appalachian basin, making us vulnerable to risks associated with operating in limited geographic areas.

Our producing properties currently are geographically concentrated in the Appalachian basin in Pennsylvania and West Virginia. At December 31, 2019, nearly 100% of our total estimated proved reserves were attributable to properties located in the Appalachian basin. As a result of this concentration in one primary region, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, state and local politics, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or interruption of the processing or transportation of natural gas, oil or NGLs.

Competition in the oil and natural gas industry is intense, making it more difficult for us to market natural gas, oil and NGLs, to secure trained personnel and appropriate services, to obtain additional properties and to raise capital.

Our cost of operations is highly dependent on third-party services, and competition for these services can be significant, especially in times when commodity prices are rising. Similarly, we compete for trained, qualified personnel, and in times of lower prices for the commodities we produce, we and other companies with similar production profiles may not be able to attract and retain this talent. Our ability to acquire 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 for acquiring properties, marketing

natural gas, oil and NGLs and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and gas industry. Certain of our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for personnel, property and services and to attract capital at lower rates. This may become more likely if prices for oil and NGLs increase faster than prices for natural gas, as natural gas comprises a greater percentage of our overall production than it does for most of the companies with whom we compete for talent.

Climate change legislation or regulations governing the emissions of greenhouse gases could result in increased operating costs and reduce demand for the natural gas, oil and NGLs we produce, and concern in financial and investment markets over greenhouse gasses and fossil fuel production could adversely affect our access to capital and the price of our common stock.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet “best available control technology” standards that will be established on a case-by-case basis. EPA rulemakings related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore natural gas and oil production sources in the United States on an annual basis, which include certain of our operations. In May 2016, the EPA finalized additional regulations to control methane and volatile organic compound emissions from certain oil and gas equipment and operations. However, in September 2018 and August 2019, the EPA issued proposed revisions to those regulations, which, if finalized, would reduce certain obligations thereunder.

Although Congress from time to time has considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or install new equipment to reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. At the same time, new laws and regulations are prompting power producers to shift from coal to natural gas, which is increasing demand.

In December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions (the “Paris Agreement”). The Paris Agreement entered into force in November 2016 after more than 70 nations, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. In June 2017, President Trump announced that the United States intends to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or a separate agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. In November 2019, the United States formally initiated the process for withdrawing from the Paris Agreement, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and natural gas industry, or that investors insist on compliance regardless of legal requirements, it could have an adverse effect on our business.

Market views of our industry generally can affect our stock price.

Factors described elsewhere, including views regarding future commodity prices, regulation and climate change, can affect the amount investors choose to invest in our industry generally. Recent years have seen a significant reduction in overall investment in exploration and production companies, resulting in a drop in individual companies’ stock prices. Separate from actual and possible governmental action, certain financial institutions have announced policies to cease investing or to divest

investments in companies, such as ours, that produce fossil fuels, and some banks have announced they no longer will lend to companies in this sector. To date these represent small fractions of overall sources of equity and debt, but that fraction could grow and thus affect our access to capital. Moreover, some equity investors are expressing concern over these matters and may prompt companies in our industry to adopt more costly practices even absent governmental action. Although we believe our practices result in low emission rates for methane and other greenhouse gases as compared to others in our industry, complying with investor sentiment may require modifications to our practices, which could increase our capital and operating expenses.

Volatility in the financial markets or in global economic factors could adversely impact our business and financial condition.

Our business may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy demand and lower commodity prices, including due to the possible impact of the coronavirus (COVID-19), increased difficulty in collecting amounts owed to us by our customers, reduced access to credit markets and the risks related to the discontinuation of LIBOR and other reference rates, including increased expenses and litigation and the effectiveness of interest rate hedge strategies. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

Any changes in U.S. trade policy could trigger retaliatory actions by affected countries, resulting in “trade wars,” in increased costs for materials necessary for our industry along with other goods imported into the United States, which may reduce customer demand for these products if the parties having to pay those tariffs increase their prices, or in trading partners limiting their trade with the United States. If these consequences are realized, the volume of economic activity in the United States, including growth in sectors that utilize our products, may be materially reduced along with a reduction in the potential export of our products. Such a reduction may materially and adversely affect commodity prices, our sales and our business.

We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our development and production operations and the transportation of our products to market are subject to complex and stringent federal, state and local laws and regulations, including those governing environmental protection, the occupational health and safety aspects of our operations, the discharge of materials into the environment, and the protection of certain plant and animal species. See “Other – Environmental Regulation” in Item 1 of Part I of this Annual Report for a description of the laws and regulations that affect us. These laws and regulations require us, our service providers and our customers to obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Environmental regulations may restrict the types, quantities and concentration of materials that may be released into the environment in connection with drilling and production activities, limit or prohibit drilling or transportation activities on certain lands lying within wilderness, wetlands, archeological sites and other protected areas, and impose substantial liabilities for pollution resulting from our operations and those of our service providers and customers. Moreover, we or they may experience delays in obtaining or be unable to obtain required permits, including as a result of government shutdowns, which may delay or interrupt our or their operations and limit our growth and revenues. In addition, various officials and candidates at the federal, state and local levels, including some presidential candidates, have proposed banning hydraulic fracturing altogether.

Failure to comply with laws and regulations can trigger a variety of administrative, civil and criminal enforcement measures, including investigatory actions, the assessment of monetary penalties, the imposition of remedial requirements, or the issuance of orders or judgments limiting or enjoining future operations. Strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. Moreover, our costs of compliance with existing laws could be substantial and may increase or unforeseen liabilities could be imposed if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. If we are not able to recover the increased costs through insurance or increased revenues, our business, financial condition, results of operations and cash flows could be adversely affected.

Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material changes to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated.

As described in more detail under “Critical Accounting Policies and Estimates – Natural Gas and Oil Properties” in Item 7 of Part II of this Annual Report, our reserve data represents the estimates of our reservoir engineers made under the supervision of our management, and our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm. Reserve engineering is a subjective process of estimating underground accumulations of natural gas, oil and NGLs that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserve data included in this document are only estimates. The process relies on

interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as using historic natural gas, oil and NGL prices rather than future projections. Additional assumptions include drilling and operating expenses, capital investing, taxes and availability of funds. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas, oil and NGLs that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas, oil and NGL reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the preceding 12-month average natural gas, oil and NGL index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Our commodity price risk management and measurement systems and economic hedging activities might not be effective and could increase the volatility of our results.

We currently seek to hedge the price of a significant portion of our estimated production through swaps, collars, floors and other derivative instruments. The systems we use to quantify commodity price risk associated with our businesses might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified. Furthermore, no single hedging arrangement can adequately address all risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist.

Our use of derivatives, through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under GAAP to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under GAAP, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to us has occurred during the applicable period. To the extent we cap or lock prices at specific levels, we would also forgo the ability to realize the higher revenues that would be realized should prices increase.

The impact of changes in market prices for natural gas, oil and NGLs on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for oil, natural gas or NGLs were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss if our production volumes are less than expected.

We may be unable to dispose of assets on attractive terms, and may be required to retain liabilities for certain matters.

Various factors could materially affect our ability to dispose of assets if and when we decide to do so, including the availability of purchasers willing to purchase the assets at prices acceptable to us, particularly in times of reduced and volatile commodity prices. Sellers typically retain liabilities for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

The implementation of derivatives legislation 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.

The Dodd-Frank Act established federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. The Dodd-Frank Act requires the CFTC, the SEC, and other regulatory authorities to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized most of its regulations under the Dodd-Frank Act, it continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, it is not possible at this time to predict the ultimate effect of the rules and regulations on our business and while most of the regulations have been adopted, any new regulations or modifications to existing regulations may increase the cost of derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and the regulations thereunder, 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 investing.

In January 2020, the CFTC proposed new amended regulations that would place federal limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. In 2016, the CFTC finalized a companion rule on aggregation of positions among entities under common ownership or control. If finalized, the position limits rule may have an impact on our ability to hedge our exposure to certain enumerated commodities.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and mandatory trading on designated contract markets or swap execution facilities. The CFTC may designate additional classes of swaps as subject to the mandatory clearing requirement in the future, but has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. The CFTC and prudential banking regulators also adopted mandatory margin requirements on uncleared swaps between swap dealers and certain other counterparties. The margin requirements are currently effective with respect to certain market participants and will be phased in over time with respect to other market participants, based on the level of an entity's swaps activity. We expect to qualify for and rely upon an end-user exception from the mandatory clearing and trade execution requirements for swaps entered to hedge our commercial risks. We also should qualify for an exception from the uncleared swaps margin requirements. However, the application of the mandatory clearing and trade execution requirements and the uncleared swaps margin requirement to other market participants, such as swap dealers, may adversely affect the cost and availability of the swaps that we use for hedging.

Further regulations relating to and interpretations of the Tax Cuts and Jobs Act may have a material impact on our financial condition and results of operations.

Significant tax reform legislation in 2017 (commonly referred to as the "Tax Cuts and Jobs Act," or the "Tax Reform Act"), brought major changes to corporate taxation, including a permanent reduction of the corporate income tax rate, a partial limitation on the deductibility of business interest expense, limitation of the deduction for certain net operating losses to 80% of current year taxable income for tax years 2018 and beyond, an indefinite net operating loss carryforward, immediate deductions for certain new investments instead of deductions for depreciation expense over time and the modification or repeal of many business deductions and credits. The Treasury Department and the Internal Revenue Service continue to release regulations relating to and interpretive guidance of the legislation contained in the Tax Reform Act. Any significant variance of our current interpretation of such legislation from any future regulations or interpretive guidance could result in a change to the presentation of our financial condition and results of operations and could negatively affect our business.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

The elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies may be proposed in the future. These changes may include, among other proposals:

- repeal of the percentage depletion allowance for natural gas and oil properties;
- elimination of current deductions for intangible drilling and development costs;
- elimination of the deduction for certain domestic production activities; and
- extension of the amortization period for certain geological and geophysical expenditures.

The passage of these or any similar changes in U.S. federal income tax laws to eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development could have an adverse effect on our financial position, results of operations and cash flows.

We may experience adverse or unforeseen tax consequences due to further developments affecting our deferred tax assets that could significantly affect our results.

Deferred tax assets, including net operating loss carryforwards, represent future savings of taxes that would otherwise be paid in cash. At December 31, 2019, we had substantial amounts of net operating loss carryforwards for U.S. federal and state income tax purposes. Our ability to utilize the deferred tax assets is dependent on the amount of future pre-tax income that we are able to generate through our operations or sale of assets. If management concludes that it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized, a valuation allowance will be recognized in the period that this conclusion is reached. In addition, limitations may exist upon use of these carryforwards in the event that a change in control of the Company occurs.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain exploration, development and production activities as well as processing of revenues and payments. We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data, analyze seismic and drilling information, conduct reservoir modeling and reserves estimation, communicate with employees and business associates, perform compliance reporting and in many other activities related to our business. Our vendors, service providers, purchasers of our production and financial institutions are also dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. Our technologies, systems, networks, and those of our business associates may become the target of cyber-attacks or information security breaches, which could lead to disruptions in critical systems, unauthorized release of confidential or protected information, corruption of data or other disruptions of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber-attack involving our information systems and related infrastructure, or that of companies with which we deal, could disrupt our business and negatively impact our operations in a variety of ways, including:

- 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 natural gas and oil resources;
- unauthorized access to personal identifying information of property lessors, working interest partners, employees and vendors, which could expose us to allegations that we did not sufficiently protect that information;
- data corruption or operational disruption of production infrastructure could result in 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; and
- a cyber-attack on a third party gathering, pipeline or rail service provider could delay or prevent us from marketing our production, resulting in a loss of revenues.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability, which could have a material adverse effect on our financial condition, results of operations or cash flows.

To date we have not experienced any material losses or interruptions relating to cyber-attacks; however, there can be no assurance that we will not suffer such losses in the future. 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.

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

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in

commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

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

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change, emissions, hydraulic fracturing, seismicity, oil spills and explosions of transmission lines, may lead to regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business. In addition, various officials and candidates at the federal, state and local levels, including some presidential candidates, have proposed banning hydraulic fracturing altogether.

Judicial decisions can affect our rights and obligations.

Our ability to develop gas, oil and NGLs depends on the leases and other mineral rights we acquire and the rights of owners of nearby properties. We operate in areas where judicial decisions have not yet definitively interpreted various contractual provisions or addressed relevant aspects of property rights, nuisance and other matters that could be the source of claims against us as a developer or operator of properties. Although we plan our activities according to our expectations of these unresolved areas, based on decisions on similar issues in these jurisdictions and decisions from courts in other states that have addressed them, courts could resolve issues in ways that increase our liabilities or otherwise restrict or add costs to our operations.

Common stockholders will be diluted if additional shares are issued.

From time to time we have issued stock to raise capital for our business, including significant offerings of new shares in 2015 and 2016. We also issue restricted stock, options and performance share units to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Anti-takeover provisions in our organizational documents and under Delaware law may impede or discourage a takeover, which could cause the market price of our common stock to decline.

We are a Delaware corporation, and the anti-takeover provisions of Delaware law impose various impediments to the ability of a third party to acquire control of us, even if a change in control would be beneficial to our existing stockholders, which, under certain circumstances, could reduce the market price of our common stock. In addition, protective provisions in our Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws or the implementation by our Board of Directors of a stockholder rights plan that could deter a takeover.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2019 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed “2019 Proved Reserves by Category and Summary Operating Data” in “Business – Exploration and Production – Our Proved Reserves” in Item 1 of this Annual Report and incorporated by reference into this Item 2.

The information regarding our proved undeveloped reserves required by Item 1203 of Regulation S-K is included under the heading “Proved Undeveloped Reserves” in “Business – Exploration and Production – Our Proved Reserves” in Item 1 of this Annual Report.

The information regarding delivery commitments required by Item 1207 of Regulation S-K is included under the heading “Sales, Delivery Commitments and Customers” in the “Business – Exploration and Production – Our Operations” in Item 1 of this Annual Report and incorporated by reference into this Item 2. For additional information about our natural gas and oil operations, we refer you to “Supplemental Oil and Gas Disclosures” in Item 8 of Part II of this Annual Report. For information concerning capital investments, we refer you to “Management’s Discussion and Analysis of Financial Condition and Results of

Operations – Liquidity and Capital Resources – Capital Investing.” We also refer you to Item 6, “Selected Financial Data” in Part II of this Annual Report for information concerning natural gas, oil and NGLs produced.

The information regarding natural gas and oil properties, wells, operations and acreage required by Item 1208 of Regulation S-K is set forth below:

Leasehold acreage as of December 31, 2019

	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Northeast Appalachia	69,643	53,435	126,926	120,559	196,569	173,994
Southwest Appalachia	353,847	205,222	118,431	82,471	472,278	287,693
Other:						
US – Other Exploration	26,880	18,278	5,034	2,263	31,914	20,541
US – Sand Wash Basin	15,551	9,056	14,977	10,792	30,528	19,848
Total US	465,921	285,991	265,368	216,085	731,289	502,076
Canada – New Brunswick ⁽¹⁾	2,518,519	2,518,519	—	—	2,518,519	2,518,519
	2,984,440	2,804,510	265,368	216,085	3,249,808	3,020,595

(1) The exploration licenses for 2,518,519 net acres in New Brunswick, Canada, have been subject to a moratorium since 2015. These licenses expire in 2021, and we impaired their value to \$0 in 2016.

Lease Expirations

The following table summarizes the leasehold acreage expiring over the next three years, assuming successful wells are not drilled to develop the acreage and leases are not extended:

	For the years ended December 31,		
	2020	2021	2022
Net acreage expiring:			
Northeast Appalachia	3,082	1,750	4,567
Southwest Appalachia ⁽¹⁾	15,584	5,804	14,536
Other:			
US – Other Exploration	11,949	5,679	650
US – Sand Wash Basin	5,630	3,425	—
Canada – New Brunswick ⁽²⁾	—	2,518,519	—

(1) Of this acreage, 1,726 net acres in 2020, 2,173 net acres in 2021 and 6,907 net acres in 2022 can be extended for an average of 4.9 years.

(2) Exploration licenses were extended through 2021 but have been subject to a moratorium since 2015. We impaired their value to \$0 in 2016.

Producing wells as of December 31, 2019

	Natural Gas		Oil		Total		Gross Wells Operated
	Gross	Net	Gross	Net	Gross	Net	
Northeast Appalachia	711	631	—	—	711	631	641
Southwest Appalachia	533	386	—	—	533	386	505
Other	6	3	11	11	17	14	17
	1,250	1,020	11	11	1,261	1,031	1,163

The information regarding drilling and other exploratory and development activities required by Item 1205 of Regulation S-K is set forth below:

Year	Exploratory					
	Productive Wells		Dry Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
2019						
Northeast Appalachia	—	—	—	—	—	—
Southwest Appalachia	—	—	—	—	—	—
Other	—	—	—	—	—	—
Total	—	—	—	—	—	—
2018						
Northeast Appalachia	—	—	—	—	—	—
Southwest Appalachia	—	—	—	—	—	—
Fayetteville Shale ⁽¹⁾	—	—	—	—	—	—
Other	—	—	—	—	—	—
Total	—	—	—	—	—	—
2017						
Northeast Appalachia	—	—	—	—	—	—
Southwest Appalachia	—	—	—	—	—	—
Fayetteville Shale ⁽¹⁾	—	—	—	—	—	—
Other	1.0	1.0	—	—	1.0	1.0
Total	1.0	1.0	—	—	1.0	1.0

(1) The Fayetteville Shale E&P assets were sold in December 2018.

Year	Development					
	Productive Wells		Dry Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
2019						
Northeast Appalachia	44.0	41.7	—	—	44.0	41.7
Southwest Appalachia	69.0	53.5	—	—	69.0	53.5
Total	113.0	95.2	—	—	113.0	95.2
2018						
Northeast Appalachia	60.0	59.5	—	—	60.0	59.5
Southwest Appalachia	76.0	59.3	—	—	76.0	59.3
Fayetteville Shale ⁽¹⁾	2.0	1.8	—	—	2.0	1.8
Total	138.0	120.6	—	—	138.0	120.6
2017						
Northeast Appalachia	83.0	80.8	—	—	83.0	80.8
Southwest Appalachia	57.0	43.6	—	—	57.0	43.6
Fayetteville Shale ⁽¹⁾	25.0	24.1	—	—	25.0	24.1
Total	165.0	148.5	—	—	165.0	148.5

(1) The Fayetteville Shale E&P assets were sold in December 2018.

The following table presents the information regarding our present activities required by Item 1206 of Regulation S-K:

Wells in progress as of December 31, 2019

	Gross	Net
Drilling:		
Northeast Appalachia	26.0	25.5
Southwest Appalachia	19.0	14.5
Total	45.0	40.0
Completing:		
Northeast Appalachia	2.0	2.0
Southwest Appalachia	5.0	4.0
Total	7.0	6.0
Drilling & Completing:		
Northeast Appalachia	28.0	27.5
Southwest Appalachia	24.0	18.5
Total	52.0	46.0

The information regarding oil and gas production, production prices and production costs required by Item 1204 of Regulation S-K is set forth below:

Production, Average Sales Price and Average Production Cost

	For the years ended December 31,		
	2019	2018	2017
Natural Gas			
Production (Bcf):			
Northeast Appalachia	459	459	395
Southwest Appalachia	150	105	85
Fayetteville Shale ⁽¹⁾	—	243	316
Other	—	—	1
Total	609	807	797
Average realized gas price, excluding derivatives (\$/Mcf):			
Northeast Appalachia	\$ 2.10	\$ 2.54	\$ 2.11
Southwest Appalachia	\$ 1.62	\$ 2.58	\$ 2.28
Fayetteville Shale ⁽¹⁾	\$ —	\$ 2.21	\$ 2.35
Total	\$ 1.98	\$ 2.45	\$ 2.23
Average realized gas price, including derivatives (\$/Mcf):	\$ 2.18	\$ 2.35	\$ 2.19
Oil			
Production (MBbls):			
Southwest Appalachia	4,673	3,355	2,228
Other	23	52	99
Total	4,696	3,407	2,327
Average realized oil price, excluding derivatives (\$/Bbl):			
Southwest Appalachia	\$ 46.86	\$ 56.71	\$ 42.93
Other	\$ 53.66	\$ 62.01	\$ 47.38
Total	\$ 46.90	\$ 56.79	\$ 43.12
Average realized oil price, including derivatives (\$/Bbl):	\$ 49.56	\$ 56.07	\$ 43.12
NGL			
Production (MBbls):			
Southwest Appalachia	23,611	19,679	14,193
Other	9	27	52
Total	23,620	19,706	14,245
Average realized NGL price, excluding derivatives (\$/Bbl):			
Southwest Appalachia	\$ 11.59	\$ 17.89	\$ 14.42
Other	\$ 7.61	\$ 28.12	\$ 26.38
Total	\$ 11.59	\$ 17.91	\$ 14.46
Average realized NGL price, including derivatives (\$/Bbl)	\$ 13.64	\$ 17.23	\$ 14.48
Total Production (Bcfe)			
Northeast Appalachia	459	459	395
Southwest Appalachia ⁽²⁾	319	243	183
Fayetteville Shale ⁽¹⁾	—	243	316
Other	—	1	3
Total	778	946	897
Lease Operating Expense			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Northeast Appalachia	\$ 0.85	\$ 0.81	\$ 0.75
Southwest Appalachia	\$ 1.02	\$ 1.08	\$ 1.07
Fayetteville Shale ⁽¹⁾	\$ —	\$ 0.98	\$ 0.97
Total	\$ 0.92	\$ 0.93	\$ 0.90

(1) The Fayetteville Shale E&P assets and associated reserves were sold in December 2018.

- (2) Approximately 317 Bcfe, 240 Bcfe and 179 Bcfe for the years ended December 31, 2019, 2018 and 2017, respectively, were produced from the Marcellus Shale formation.

During 2019, we were required to file Form 23, “Annual Survey of Domestic Oil and Gas Reserves,” with the U.S. Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in “Supplemental Oil and Gas Disclosures” in Item 8 of Part II of this Annual Report. The primary differences are that Form 23 reports gross reserves, including the royalty owners’ share, and includes reserves for only those properties of which we are the operator.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than that we endeavor to conduct prior to drilling, which is consistent with standard practice in the oil and natural gas industry. Generally, before we commence drilling operations on properties that we operate, we conduct a title examination and perform curative work with respect to significant defects that we identify. We believe that we have performed title review with respect to substantially all of our active properties that we operate.

ITEM 3. LEGAL PROCEEDINGS

We are subject to various litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic incidents, pollution, contamination, encroachment on others’ property or nuisance. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. It is not possible at this time to estimate the amount of any additional loss, or range of loss that is reasonably possible, but based on the nature of the claims, management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows, for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management’s view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or results of operations.

See “Litigation” in Note 10 to the consolidated financial statements included in this Annual Report for further details on our current legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Our sand mining facility in Arkansas, which previously supported our Fayetteville Shale operations, is subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Annual Report.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange (the "NYSE") under the symbol "SWN." On February 25, 2020, the closing price of our common stock trading under the symbol "SWN" was \$1.50 and we had 2,360 stockholders of record.

We currently do not pay dividends on our common stock, and we do not anticipate paying any cash dividends in the foreseeable future. All decisions regarding the declaration and payment of dividends and stock repurchases are at the discretion of our Board of Directors and will be evaluated regularly in light of our financial condition, earnings, growth prospects, funding requirements, applicable law and any other factors that our Board deems relevant.

Information required by Item 5 of Part II with respect to equity compensation plans will be included under the caption Equity Compensation Plans in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 19, 2020, and is incorporated herein by reference.

Issuer Purchases of Equity Securities

In 2018, we repurchased 39,061,269 of our outstanding common stock for approximately \$180 million at an average price of \$4.63 per share. In the first quarter of 2019, we completed our share repurchase program by purchasing 5,260,687 shares of our common stock for approximately \$21 million at an average price of \$3.84 per share.

The table below sets forth information with respect to purchases of our common stock made by us or on our behalf during the quarter ended December 31, 2019:

Period	Total Number of Shares Purchased ⁽¹⁾	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 2019	—	\$ —	n/a	n/a
November 2019	—	\$ —	n/a	n/a
December 2019	92,529	\$ 1.92	n/a	n/a
Total fourth-quarter 2019:	92,529	\$ 1.92	n/a	

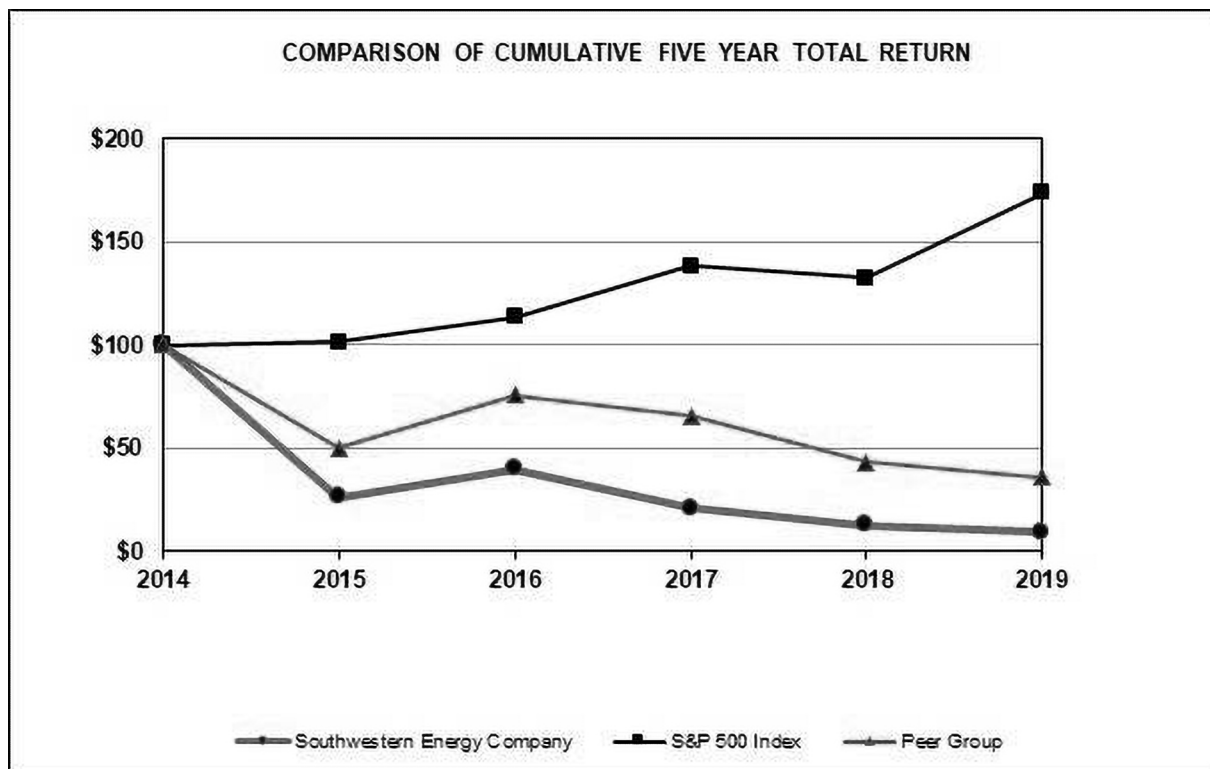
(1) Reflects shares retired by us to satisfy applicable tax withholding obligations due on employee stock plan share issuances.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2019, 2018 or 2017.

STOCK PERFORMANCE GRAPH

The following graph compares, for the last five years, the performance of our common stock to the S&P 500 Index and our peer group. Our peer group consists of Antero Resources Corporation, Cabot Oil & Gas Corporation, Callon Petroleum Company, Carizzo Oil & Gas, Inc., Chesapeake Energy Corporation, CNX Resources Corporation, Continental Resources, Inc., Devon Energy Corporation, EQT Corporation, Gulfport Energy Corporation, Murphy Oil Corporation, Oasis Petroleum Inc., Range Resources Corporation, SM Energy Company, Whiting Petroleum Corporation and WPX Energy, Inc. The chart assumes that the value of the investment in our common stock and each index was \$100 at December 31, 2014, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance:



	2014	2015	2016	2017	2018	2019
Southwestern Energy Company	\$ 100	\$ 26	\$ 40	\$ 20	\$ 12	\$ 9
S&P 500 Index	100	101	114	138	132	174
Peer Group	100	50	76	65	43	36

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2019. This information and the notes thereto are derived from our consolidated financial statements. We refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Financial Statements and Supplementary Data.”

	2019	2018	2017	2016	2015
	<i>(in millions except shares, per share, stockholder data and percentages)</i>				
Financial Review					
Operating revenues:					
Exploration and production	\$ 1,703	\$ 2,525	\$ 2,086	\$ 1,413	\$ 2,074
Marketing	2,850	3,745	3,198	2,569	3,119
Intersegment revenues	(1,515)	(2,408)	(2,081)	(1,546)	(2,060)
	<u>3,038</u>	<u>3,862</u>	<u>3,203</u>	<u>2,436</u>	<u>3,133</u>
Operating costs and expenses:					
Marketing purchases	1,320	1,229	976	864	852
Operating and general and administrative	886	994	904	839	935
(Gain) loss on sale of operating assets, net	2	(17)	(6)	—	(283)
Restructuring charges	11	39	—	73	—
Depreciation, depletion and amortization	471	560	504	436	1,091
Impairments	16	171	—	2,321	6,950
Taxes, other than income taxes	62	89	94	93	110
	<u>2,768</u>	<u>3,065</u>	<u>2,472</u>	<u>4,626</u>	<u>9,655</u>
Operating income (loss)	270	797	731	(2,190)	(6,522)
Interest expense, net	65	124	135	88	56
Gain (loss) on derivatives	274	(118)	422	(339)	47
Gain (loss) on early extinguishment of debt	8	(17)	(70)	(51)	—
Other income (loss), net	(7)	—	5	(4)	(30)
	<u>480</u>	<u>538</u>	<u>953</u>	<u>(2,672)</u>	<u>(6,561)</u>
Income (loss) before income taxes	480	538	953	(2,672)	(6,561)
Provision (benefit) for income taxes:					
Current	(2)	1	(22)	(7)	(2)
Deferred	(409)	—	(71)	(22)	(2,003)
	<u>(411)</u>	<u>1</u>	<u>(93)</u>	<u>(29)</u>	<u>(2,005)</u>
Net income (loss)	891	537	1,046	(2,643)	(4,556)
Mandatory convertible preferred stock dividend	—	—	108	108	106
Participating securities – mandatory convertible preferred stock	—	2	123	—	—
Net income (loss) attributable to common stock	<u>\$ 891</u>	<u>\$ 535</u>	<u>\$ 815</u>	<u>\$ (2,751)</u>	<u>\$ (4,662)</u>
Net cash provided by operating activities	\$ 964	\$ 1,223	\$ 1,097	\$ 498	\$ 1,580
Net cash provided by (used in) investing activities	\$ (1,045)	\$ 359	\$ (1,252)	\$ (162)	\$ (1,638)
Net cash provided by (used in) financing activities	\$ (115)	\$ (2,297)	\$ (352)	\$ 1,072	\$ 20
Common Stock Statistics					
Earnings (loss) per share:					
Net income (loss) attributable to common stockholders – Basic	\$ 1.65	\$ 0.93	\$ 1.64	\$ (6.32)	\$ (12.25)
Net income (loss) attributable to common stockholders – Diluted	\$ 1.65	\$ 0.93	\$ 1.63	\$ (6.32)	\$ (12.25)
Book value per average diluted share	\$ 6.01	\$ 4.10	\$ 3.95	\$ 2.11	\$ 6.00
Market price at year-end	\$ 2.42	\$ 3.41	\$ 5.58	\$ 10.82	\$ 7.11
Number of stockholders of record at year-end	2,420	2,886	3,216	3,292	3,415
Average diluted shares outstanding	540,382,914	576,642,808	500,804,297	435,337,402	380,521,039

	<u>2019</u>	<u>2018</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Capitalization (in millions)					
Total debt	\$ 2,242	\$ 2,318	\$ 4,391	\$ 4,653	\$ 4,705
Total equity	<u>3,246</u>	<u>2,362</u>	<u>1,979</u>	<u>917</u>	<u>2,282</u>
Total capitalization	<u>\$ 5,488</u>	<u>\$ 4,680</u>	<u>\$ 6,370</u>	<u>\$ 5,570</u>	<u>\$ 6,987</u>
Total assets	<u>\$ 6,717</u>	<u>\$ 5,797</u>	<u>\$ 7,521</u>	<u>\$ 7,076</u>	<u>\$ 8,086</u>
Capitalization ratios:					
Debt	41 %	50 %	69 %	84 %	67 %
Equity	59 %	50 %	31 %	16 %	33 %

Capital Investments (in millions) ⁽¹⁾

Exploration and production	\$ 1,138	\$ 1,231	\$ 1,248	\$ 623	\$ 2,258
Marketing (formerly Midstream)	—	9	32	21	167
Other	<u>2</u>	<u>8</u>	<u>13</u>	<u>4</u>	<u>12</u>
	<u>\$ 1,140</u>	<u>\$ 1,248</u>	<u>\$ 1,293</u>	<u>\$ 648</u>	<u>\$ 2,437</u>

Exploration and Production

Natural gas:					
Production (Bcf)	609	807	797	788	899
Average realized price, including derivatives (\$/Mcf)	\$ 2.18	\$ 2.35	\$ 2.19	\$ 1.64	\$ 2.37
Average realized price, excluding derivatives (\$/Mcf)	\$ 1.98	\$ 2.45	\$ 2.23	\$ 1.59	\$ 1.91
Oil:					
Production (MMbbls)	4,696	3,407	2,327	2,192	2,265
Average realized price, including derivatives (\$/Bbl)	\$ 49.56	\$ 56.07	\$ 43.12	\$ 31.20	\$ 33.25
Average realized price, excluding derivatives (\$/Bbl)	\$ 46.90	\$ 56.79	\$ 43.12	\$ 31.20	\$ 33.25
NGL:					
Production (MMbbls)	23,620	19,706	14,245	12,372	10,702
Average realized price, including derivatives (\$/Bbl)	\$ 13.64	\$ 17.23	\$ 14.48	\$ 7.46	\$ 6.80
Average realized price, excluding derivatives (\$/Bbl)	\$ 11.59	\$ 17.91	\$ 14.46	\$ 7.46	\$ 6.80
Total production (Bcfe)	778	946	897	875	976
Lease operating expenses per Mcfe	\$ 0.92	\$ 0.93	\$ 0.90	\$ 0.87	\$ 0.92
General and administrative expenses per Mcfe	\$ 0.18 ⁽²⁾	\$ 0.19 ⁽³⁾	\$ 0.22 ⁽⁴⁾	\$ 0.22 ⁽⁵⁾	\$ 0.21
Taxes, other than income taxes per Mcfe	\$ 0.08	\$ 0.09 ⁽⁶⁾	\$ 0.10	\$ 0.10 ⁽⁷⁾	\$ 0.10
Proved reserves at year-end:					
Natural gas (Bcf)	8,630	8,044	11,126	4,866	5,917
Oil (MMBbls)	72.9	69.0	65.6	10.5	8.8
NGLs (MMBbls)	<u>608.8</u>	<u>577.1</u>	<u>542.4</u>	<u>53.9</u>	<u>40.9</u>
Total reserves (Bcfe)	<u>12,721</u>	<u>11,921</u>	<u>14,775</u>	<u>5,253</u>	<u>6,215</u>

Marketing (formerly Midstream)

Volumes marketed (Bcfe)	1,101	1,163	1,067	1,062	1,127
Volumes gathered (Bcf) ⁽⁸⁾	—	382	499	601	799

- (1) Capital investments include an increase of \$34 million for 2019, a decrease of \$53 million for 2018, an increase of \$43 million for 2016, and a decrease of \$33 million for 2015, related to the change in accrued expenditures between years. There was no impact to 2017.
- (2) Excludes \$11 million of restructuring charges, a \$6 million residual guarantee short-fall payment to the previous lessor of our headquarters building and \$6 million of legal settlement charges for 2019.
- (3) Excludes \$36 million of restructuring charges and \$9 million of legal settlement charges for 2018.
- (4) Excludes \$5 million of legal settlements for 2017.
- (5) Excludes \$78 million of restructuring and other one-time charges for 2016.
- (6) Excludes \$1 million of restructuring charges for 2018.
- (7) Excludes \$3 million of restructuring charges for 2016.
- (8) Our Fayetteville Shale related midstream gathering assets were sold in December 2018. Substantially all of the gathered volumes in each of the years presented relate to midstream gathering assets that have been divested.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis is the Company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the Company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. In many cases you can identify forward-looking statements by words such as "anticipate," "intend," "plan," "project," "estimate," "continue," "potential," "should," "could," "may," "will," "objective," "guidance," "outlook," "effort," "expect," "believe," "predict," "budget," "projection," "goal," "forecast," "target" or similar words. Unless required to do so under the federal securities laws, the Company does not undertake to update, revise or correct any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "Cautionary Statement about Forward-Looking Statements."

OVERVIEW

Background

Southwestern Energy Company (including its subsidiaries, collectively, "we," "our," "us," "the Company" or "Southwestern") is an independent energy company engaged in natural gas, oil and NGLs exploration, development and production, which we refer to as "E&P." We are also focused on creating and capturing additional value through our marketing business, which we call "Marketing" but previously referred to as "Midstream" when it included the operations of gathering systems. We conduct most of our businesses through subsidiaries, and we currently operate exclusively in the lower 48 United States. Our historical financial and operating results include the Fayetteville Shale E&P and related midstream gathering businesses which were sold in early December 2018.

E&P. Our primary business is the exploration for and production of natural gas, oil and NGLs, with our ongoing operations focused on the development of unconventional natural gas reservoirs located in Pennsylvania and West Virginia. Our operations in northeast Pennsylvania, which we refer to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Our operations in West Virginia and southwest Pennsylvania, which we refer to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, our properties in Pennsylvania and West Virginia are herein referred to as "Appalachia." We also have drilling rigs located in Pennsylvania and West Virginia, and we provide certain oilfield products and services, principally serving our E&P operations through vertical integration.

Marketing. Our marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil, and NGLs primarily produced in our E&P operations. In December 2018, we divested almost all of our midstream gathering assets as part of the Fayetteville Shale sale.

Focus in 2019. In 2019, we continued our strategy to reposition the Company through portfolio optimization, balance sheet management and leveraging our technical, commercial and operational expertise to improve margins. We continued our strategic shift towards prioritizing the development of our high-value, liquids-rich Southwest Appalachia assets over our pure natural gas assets. We strengthened our balance sheet through an additional debt reduction of \$80 million (net) and by amending our revolving credit facility to extend the maturity into 2024, which improved our debt maturity profile while preserving financial and operational flexibility. We made further technological advances in drilling longer laterals with increased precision and completion optimization that enhanced well productivity and significantly reduced our well costs on a per lateral foot basis, resulting in improved returns. In addition, we focused on identifying and implementing opportunities to lower our overall cost structure. We added to our derivative portfolio, limiting the impact of price volatility on approximately 604 Bcfe and 307 Bcfe of our forecasted 2020 and 2021 production, respectively, through the use of commodity derivatives.

Recent Financial and Operating Results

Significant operating and financial highlights for 2019 include:

Total Company

- Net income attributable to common stock of \$891 million, or \$1.65 per diluted share, up from a net income attributable to common stock of \$535 million, or \$0.93 per diluted share, in 2018. Net income increased in 2019 as a \$409 million increase in deferred tax benefit, a \$392 million increase in net derivative gains and a \$59 million decrease in interest expense more than offset a \$527 million decrease in operating income.

- Operating income of \$270 million for the year ended December 31, 2019 decreased 66% from \$797 million in 2018. The decrease was primarily due to lower margins associated with reduced commodity prices and the divestiture of the Fayetteville Shale E&P and related midstream gathering assets in December 2018.
- Net cash provided by operating activities of \$964 million was down 21% from \$1,223 million in 2018 primarily due to the decrease in operating income net of depreciation, depletion and amortization and non-cash impairments, partially offset by the improvement in settled derivatives and positive change in assets and liabilities.
- Total capital invested of \$1,140 million was down 9% from \$1,248 million in 2018.
- We repurchased \$62 million of our outstanding long-term senior notes at a discount and recognized a gain on the extinguishment of debt of \$8 million. In addition, we retired the remaining \$52 million principal of our outstanding senior notes that were due in January 2020.

E&P

- E&P segment operating income of \$283 million was down 64%, compared to \$794 million in 2018. This excludes the impact of derivatives.
- Year-end reserves of 12,721 Bcfe increased 800 Bcfe, or 7%, from 11,921 Bcfe at the end of 2018, resulting from 1,195 Bcfe of additions and 385 Bcfe of revisions, partially offset by 778 Bcfe of production and 2 Bcfe of sales.
- Total net production of 778 Bcfe was comprised of 78% natural gas, 18% NGLs and 4% oil. In 2018, E&P segment production volumes of 946 Bcfe included 243 Bcf of production from our operations in the Fayetteville Shale, which was sold in December 2018. Excluding the impact of production from the sold Fayetteville Shale assets, our production increased 11% from 703 Bcfe in 2018, and our liquids production increased 23% over the same period.
- Excluding the effect of derivatives, our realized natural gas price of \$1.98 per Mcf, realized oil price of \$46.90 per barrel and realized NGL price of \$11.59 per barrel decreased 19%, 17% and 35%, respectively, from 2018. Our weighted average realized price excluding the effect of derivatives of \$2.18 per Mcfe decreased 18% from the same period in 2018.
- The E&P segment invested capital totaling \$1,138 million, drilling 105 wells, completing 116 wells and placing 113 wells to sales.

Outlook

We expect to continue to exercise capital discipline in our 2020 capital investment program by investing within cash flow from operations, net of changes in working capital, supplemented by earmarked proceeds of the Fayetteville Shale sale that in the meantime have been used to reduce debt. We remain committed to our focus on optimizing our portfolio by concentrating our efforts on our highest return investment opportunities, looking for ways to optimize our cost structure and to maximize margins in each core area of our business and further developing our knowledge of our asset base. We believe that we and our industry will continue to face challenges due to the uncertainty of natural gas, oil and NGL prices in the United States, changes in laws, regulations and investor sentiment, and other key factors described above under “Risk Factors.”

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We report on our segments as if they were stand-alone operations and accordingly discuss their results prior to any intersegment eliminations. Restructuring charges, interest expense, gain (loss) on derivatives, gain (loss) on early extinguishment of debt and income taxes are discussed on a consolidated basis.

We have applied the Securities and Exchange Commission’s recently adopted FAST Act Modernization and Simplification of Regulation S-K, which limits the discussion to the two most recent fiscal years. This discussion and analysis deals with comparisons of material changes in the consolidated financial statements for fiscal 2019 and fiscal 2018. For the comparison of fiscal 2018 and fiscal 2017, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Part II, Item 7 of our 2018 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 28, 2019.

E&P

The 2018 information in the table below includes the financial results from E&P assets in the Fayetteville Shale that were sold in December 2018.

<i>(in millions)</i>	For the years ended December 31,	
	2019	2018
Revenues ⁽¹⁾	\$ 1,703	\$ 2,525
Operating costs and expenses	1,420 ⁽²⁾	1,731 ⁽³⁾
Operating income	\$ 283	\$ 794
Gain (loss) on derivatives, settled ⁽⁴⁾	\$ 180	\$ (94)

(1) Includes \$2 million and \$5 million in third-party water sales for the years ended December 31, 2019 and 2018, respectively.

(2) Includes \$11 million of restructuring charges and \$13 million of non-cash, non-full cost pool impairments for the year ended December 31, 2019.

(3) Includes \$37 million of restructuring charges, an \$18 million loss on the sale of assets and \$15 million of non-cash, non-full cost pool asset impairments for the year ended December 31, 2018.

(4) Includes \$1 million amortization of premiums paid related to certain natural gas call options for each of the years ended December 31, 2019 and 2018.

Operating Income

- E&P segment operating income for the year ended December 31, 2018 included \$105 million related to our operations in the Fayetteville Shale, which were sold in December 2018. Excluding the amounts related to Fayetteville, our E&P segment operating income decreased \$406 million for the year ended December 31, 2019, compared to the same period in 2018, as lower margins associated with decreased commodity pricing were only partially offset by increased efficiencies and production.

Revenues

The following illustrate the effects on sales revenues associated with changes in commodity prices and production volumes:

<i>(in millions except percentages)</i>	For the years ended December 31,			
	Natural Gas	Oil	NGLs	Total
2018 sales revenues ⁽¹⁾	\$ 1,974	\$ 193	\$ 353	\$ 2,520
Changes associated with the Fayetteville Shale sale ⁽²⁾	(537)	—	—	(537)
2018 sales revenues, net of Fayetteville Shale revenues	1,437	193	353	1,983
Changes associated with prices	(342)	(46)	(149)	(537)
Changes associated with production volumes	112	73	70	255
2019 sales revenues ⁽³⁾	\$ 1,207	\$ 220	\$ 274	\$ 1,701
Increase (decrease) from 2018, net of Fayetteville Shale revenues	(16)%	14 %	(22)%	(14)%

(1) Excludes \$5 million in other operating revenues for the year ended December 31, 2018 related to third-party water sales.

(2) This amount represents the revenues associated with the Fayetteville Shale assets, which were sold in December 2018. There were no Fayetteville Shale revenues in 2019.

(3) Excludes \$2 million in other operating revenues for the year ended December 31, 2019 related to third-party water sales.

Production Volumes

	For the years ended December 31,		
	2019	2018	Increase/ (Decrease)
Natural Gas (Bcf)			
Northeast Appalachia	459	459	—%
Southwest Appalachia	150	105	43%
Fayetteville Shale ⁽¹⁾	—	243	(100)%
Other	—	—	—%
Total	609	807	(25)%
Oil (MBbls)			
Southwest Appalachia	4,673	3,355	39%
Other	23	52	(56)%
Total	4,696	3,407	38%
NGL (MBbls)			
Southwest Appalachia	23,611	19,679	20%
Other	9	27	(67)%
Total	23,620	19,706	20%
Production volumes by area (Bcfe):			
Northeast Appalachia	459	459	—%
Southwest Appalachia ⁽²⁾	319	243	31%
Fayetteville Shale ⁽¹⁾	—	243	(100)%
Other	—	1	(100)%
Total	778	946	(18)%
Production percentage:			
Natural gas	78 %	85 %	
Oil	4 %	2 %	
NGL	18 %	13 %	

(1) The Fayetteville Shale assets were sold in December 2018.

(2) Approximately 317 Bcfe and 240 Bcfe for the years ended December 31, 2019 and 2018, respectively, were produced from the Marcellus Shale formation.

- E&P segment production volumes for the year ended December 31, 2018 included 243 Bcf of production from our operations in the Fayetteville Shale which were sold in December 2018. Excluding this amount, production volumes for our E&P segment increased 75 Bcfe for the year ended December 31, 2019, compared to the same period in 2018, primarily due to a 31% increase in production volumes in Southwest Appalachia.
- Oil and NGL production increased 38% and 20%, respectively, for the year ended December 31, 2019, compared to 2018, reflecting our investment in our liquids-rich acreage in Southwest Appalachia.

Commodity Prices

The price we expect to receive for our production is a critical factor in determining the capital investments we make to develop our properties. Commodity prices fluctuate due to a variety of factors we cannot control or predict, including increased supplies of natural gas, oil or NGLs due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources. These factors impact supply and demand, which in turn determine the sales prices for our production. In addition to these factors, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. We will continue to evaluate the commodity price environments and adjust the pace of our activities in order to maintain appropriate liquidity and financial flexibility.

	For the years ended December 31,		
	2019	2018	Increase/ (Decrease)
Natural Gas Price:			
NYMEX Henry Hub Price <i>(\$/MMBtu)</i> ⁽¹⁾	\$ 2.63	\$ 3.09	(15)%
Discount to NYMEX ⁽²⁾	(0.65)	(0.64)	2%
Average realized gas price, excluding derivatives <i>(\$/Mcf)</i>	\$ 1.98	\$ 2.45	(19)%
Loss on settled financial basis derivatives <i>(\$/Mcf)</i>	—	(0.04)	
Gain (loss) on settled commodity derivatives <i>(\$/Mcf)</i>	0.20	(0.06)	
Average realized gas price, including derivatives <i>(\$/Mcf)</i>	\$ 2.18	\$ 2.35	(7)%
Oil Price:			
WTI oil price <i>(\$/Bbl)</i>	\$ 57.03	\$ 64.77	(12)%
Discount to WTI	(10.13)	(7.98)	27%
Average oil price, excluding derivatives <i>(\$/Bbl)</i>	\$ 46.90	\$ 56.79	(17)%
Gain (loss) on settled derivatives <i>(\$/Bbl)</i>	2.66	(0.72)	
Average oil price, including derivatives <i>(\$/Bbl)</i>	\$ 49.56	\$ 56.07	(12)%
NGL Price:			
Average realized NGL price, excluding derivatives <i>(\$/Bbl)</i>	\$ 11.59	\$ 17.91	(35)%
Gain (loss) on settled derivatives <i>(\$/Bbl)</i>	2.05	(0.68)	
Average realized NGL price, including derivatives <i>(\$/Bbl)</i>	\$ 13.64	\$ 17.23	(21)%
Percentage of WTI, excluding derivatives	20 %	28 %	
Total Weighted Average Realized Price:			
Excluding derivatives <i>(\$/Mcfe)</i>	\$ 2.18	\$ 2.66	(18)%
Including derivatives <i>(\$/Mcfe)</i>	\$ 2.42	\$ 2.57	(6)%

(1) Based on last day settlement prices from monthly futures contracts.

(2) This discount includes a basis differential, a heating content adjustment, physical basis sales, third-party transportation charges and fuel charges, and excludes financial basis hedges.

We receive a sales price for our natural gas at a discount to average monthly NYMEX settlement prices based on heating content of the gas, locational basis differentials and transportation and fuel charges. Additionally, we receive a sales price for our oil and NGLs at a difference to average monthly West Texas Intermediate settlement and Mont Belvieu NGL composite prices, respectively, due to a number of factors including product quality, composition and types of NGLs sold, locational basis differentials and transportation and fuel charges.

We regularly enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas, oil and NGL production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials. We refer you to Item 7A, Quantitative and Qualitative Disclosures about Market Risk, of this Annual Report, Note 6 to the consolidated financial statements included in this Annual Report, and our derivative risk factor for additional discussion about our derivatives and risk management activities.

The table below presents the amount of our future production in which the impact of basis volatility has been limited as of December 31, 2019:

	Volume <i>(Bcf)</i>	Basis Differential
Financial Basis Swaps – Natural Gas		
2020	198	\$ (0.31)
2021	86	0.04
2022	45	(0.50)
Total	329	
Physical Sales Arrangements – Natural Gas		
2020	165	\$ (0.04)
2021	50	(0.28)
Total	215	

In addition to limiting the impact of basis volatility, the table below presents the amount of our future production in which the impact of price volatility has been limited through the use of derivatives as of December 31, 2019:

	2020	2021	2022
Natural gas (Bcf)	496	260	31
Oil (MBbls)	5,402	3,029	438
Ethane (MBbls)	7,520	2,410	—
Propane (MBbls)	5,112	2,460	—
Total financial protection on future production (Bcfe)	<u>604</u>	<u>307</u>	<u>34</u>

We refer you to Note 6 to the consolidated financial statements included in this Annual Report for additional details about our derivative instruments.

Operating Costs and Expenses

	For the years ended December 31,		
	2019	2018 ⁽¹⁾	Increase/ (Decrease)
<i>(in millions except percentages)</i>			
Lease operating expenses	\$ 722	\$ 878	(18)%
General & administrative expenses	150 ⁽²⁾	186 ⁽³⁾	(19)%
Restructuring charges	11	37	(70)%
Taxes, other than income taxes	62	83	(25)%
Full cost pool amortization	439	479	(8)%
Non-full cost pool DD&A	23	35	(34)%
Impairments	13	15	(13)%
Loss on sale of assets	—	18	(100)%
Total operating costs	<u>\$ 1,420</u>	<u>\$ 1,731</u>	<u>(18)%</u>

(1) Includes eleven months of expenses from our Fayetteville Shale operations, which were sold in December 2018.

(2) Includes a \$6 million residual value guarantee short-fall payment to the previous lessor of our headquarters building and \$6 million of legal settlement charges for the year ended December 31, 2019.

(3) Includes \$9 million of legal settlement charges for the year ended December 31, 2018.

	For the years ended December 31,		
	2019	2018	Increase/ (Decrease)
<u>Average unit costs per Mcfe:</u>			
Lease operating expenses ⁽¹⁾	\$ 0.92	\$ 0.93	(1)%
General & administrative expenses	\$ 0.18 ⁽²⁾	\$ 0.19 ⁽³⁾	(5)%
Taxes, other than income taxes	\$ 0.08	\$ 0.09 ⁽⁴⁾	(11)%
Full cost pool amortization	\$ 0.56	\$ 0.51	10%

(1) Includes post-production costs such as gathering, processing, fractionation and compression.

(2) Excludes \$11 million in restructuring charges, a \$6 million residual value guarantee short-fall payment to the previous lessor of our headquarters building and \$6 million of legal settlement charges for the year ended December 31, 2019.

(3) Excludes \$36 million in restructuring charges, \$9 million of legal settlement charges for the year ended December 31, 2018.

(4) Excludes \$1 million of restructuring charges for the year ended December 31, 2018.

Lease Operating Expenses

- Lease operating expenses per Mcfe decreased \$0.01 for the year ended December 31, 2019, compared to 2018, as a \$0.02 per Mcfe decrease associated with the Fayetteville Shale sale was partially offset by a \$0.01 per Mcfe increase primarily related to increased liquids production, which includes higher costs from processing and NGL fees.

General and Administrative Expenses

- General and administrative expenses in 2019 included a \$6 million residual value guarantee short-fall payment to the previous lessor of our headquarters building and \$6 million in legal settlement charges. 2018 included \$9 million in legal settlement charges. Excluding these amounts, general and administrative expenses decreased \$39 million for the year ended December 31, 2019, compared to 2018, primarily due to decreased personnel costs and the implementation of cost reduction initiatives.

- On a per Mcfe basis, excluding restructuring, legal settlement charges and the residual value guarantee short-fall payment, general and administrative expenses per Mcfe decreased by \$0.01 for the year ended December 31, 2019, compared to 2018, as a decrease in expenses more than offset an 18% decrease in production volumes primarily associated with the Fayetteville Shale sale.

Taxes, Other than Income Taxes

- Taxes other than income taxes per Mcfe may vary from period to period due to changes in ad valorem and severance taxes that result from the mix of our production volumes and fluctuations in commodity prices. Taxes, other than income taxes, per Mcfe decreased \$0.01 per Mcfe for the year ended December 31, 2019, compared to the same period in 2018, primarily due to a \$7 million severance tax refund/credit received in the fourth quarter of 2019 related to additional favorable assessments on deductible expenses in Southwest Appalachia and lower realized commodity pricing in 2019. In 2018, we received an \$8 million severance tax refund related to a favorable assessment on deductible expenses in Southwest Appalachia which reduced our average severance tax rate applied in 2019.

Full Cost Pool Amortization

- Our full cost pool amortization rate increased \$0.05 per Mcfe for the year ended December 31, 2019, as compared to 2018. The increase in the average amortization rate resulted primarily as a result of the impact of capital investments and the further evaluation of our unproved properties during the year and the impact of the Fayetteville Shale sale, which reduced our total natural gas reserves along with the carrying value of our full cost pool assets.
- The amortization rate is impacted by the timing and amount of reserve additions and the future development costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from non-cash full cost ceiling impairments, proceeds from the sale of properties that reduce the full cost pool, and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes.
- Unevaluated costs excluded from amortization were \$1.5 billion at December 31, 2019 compared to \$1.8 billion at December 31, 2018. The unevaluated costs excluded from amortization decreased, as compared to 2018, as the evaluation of previously unevaluated properties totaling \$507 million in 2019 was only partially offset by the impact of \$258 million of unevaluated capital invested during the same period.

See “Supplemental Oil and Gas Disclosures” in Item 8 of Part II of this Annual Report for additional information regarding our unevaluated costs excluded from amortization.

Impairments

- During the year ended December 31, 2019, we recognized non-cash impairments of \$13 million associated with non-core E&P assets.
- In accordance with accounting guidance for Property, Plant and Equipment, assets held for sale are measured at the lower of carrying value or fair value less costs to sell. Because the assets outside the full cost pool associated with the Fayetteville Shale sale met the criteria for held for sale accounting in the third quarter of 2018, we determined the carrying value of certain non-full cost pool E&P assets exceeded the fair value less costs to sell. As a result, a non-cash impairment charge of \$15 million was recorded during the year ended December 31, 2018.

Marketing

The 2018 information in the table below includes the results from the gas gathering assets included in the Fayetteville Shale sale which closed in December 2018.

	For the years ended December 31,		
	2019	2018	Increase/ (Decrease)
<i>(in millions except percentages)</i>			
Marketing revenues	\$ 2,849	\$ 3,497	(19)%
Gas gathering revenues ⁽¹⁾	—	248	(100)%
Other operating revenues	1	—	100%
Marketing purchases	2,833	3,455	(18)%
Operating costs and expenses ⁽¹⁾	25	166 ⁽²⁾	(85)%
Impairments	3	155 ⁽³⁾	(98)%
(Gain) loss on sale of assets, net	2	(35)	(106)%
Operating income (loss)	\$ (13)	\$ 4	(425)%
Volumes marketed <i>(Bcfe)</i>	1,101	1,163	(5)%
Volumes gathered <i>(Bcf)</i> ⁽¹⁾	—	382	(100)%
Affiliated E&P natural gas production marketed	79 %	93 %	
Affiliated E&P oil and NGL production marketed	61 %	66 %	

(1) Amounts for 2018 include our Fayetteville Shale-related midstream gathering business, which was sold in December 2018.

(2) Includes \$2 million of restructuring charges for the year ended December 31, 2018.

(3) Includes a \$145 million non-cash impairment related to the midstream gathering assets associated with the Fayetteville Shale sale in December 2018 and a \$10 million non-cash impairment related to certain non-core gathering assets for the year ended December 31, 2018.

Operating Income

- Marketing operating income for the year ended December 31, 2018 included a \$7 million loss related to our midstream gathering operations in the Fayetteville Shale, which we sold in December 2018. Excluding this amount, operating income decreased \$24 million for the year ended December 31, 2019, compared to 2018, primarily due to a \$26 million decrease in marketing margin.
- The margin generated from marketing activities was \$16 million and \$42 million for the years ended December 31, 2019 and 2018, respectively.

Marketing margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities, related cost of transportation and the ultimate disposition of those commodities. Increases and decreases in marketing revenues due to changes in commodity prices and volumes marketed are largely offset by corresponding changes in marketing purchase expenses. Efforts to mitigate the costs of excess transportation capacity can result in greater expenses and therefore lower Marketing margins.

Revenues

- Revenues from our marketing activities decreased \$648 million for the year ended December 31, 2019, compared to 2018, primarily due to a 14% decrease in the price received for volumes marketed and a 62 Bcfe decrease in the volumes marketed.

Operating Costs and Expenses

- Marketing operating costs and expenses for the year ended December 31, 2018 included \$140 million related to our midstream gathering operations in the Fayetteville Shale, which were sold in December 2018. Excluding this amount, operating costs and expenses decreased \$1 million for the year ended December 31, 2019, compared to the year ended December 31, 2018, primarily due to decreased personnel costs and the implementation of cost reduction initiatives.

Impairments

- In the third quarter of 2019, we recorded non-cash impairments of \$3 million to non-core gathering assets.

- During 2018, we determined the carrying value of our midstream gathering assets held for sale exceeded the fair value less the costs to sell. As a result, we recorded a non-cash impairment charge of \$145 million in 2018. Additionally, in 2018, we recognized a \$10 million non-cash impairment on unrelated non-core gathering assets.

Consolidated

Restructuring Charges

For the year ended December 31, 2019, we recognized total restructuring charges of \$11 million, of which \$6 million primarily related to office consolidation and \$5 million in cash severance, including payroll taxes withheld. As of December 31, 2019, we had recorded a liability of \$2 million related to severance to be paid out in 2020.

In June 2018, we announced a workforce reduction plan, which resulted primarily from our previously announced study of structural, process and organizational changes to enhance shareholder value and continues with respect to other aspects of our business and activities. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were canceled. We recognized \$23 million in restructuring charges related to the workforce reduction plan for the year ended December 31, 2018.

In December 2018, we closed the sale of the equity in certain of our subsidiaries that owned and operated our Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, most employees associated with those assets became employees of the buyer, although the employment of some was terminated. All affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. We incurred \$12 million in severance costs related to the Fayetteville Shale sale for the year ended December 31, 2018 and have recognized these costs as restructuring charges.

As a result of the Fayetteville Shale sale during 2018, we incurred \$4 million in charges primarily related to office consolidation and recognized these costs as restructuring charges for the year ended December 31, 2018.

Interest Expense

	For the years ended December 31,		
	2019	2018	Increase/ (Decrease)
<i>(in millions except percentages)</i>			
Gross interest expense:			
Senior notes	\$ 155	\$ 196	(21)%
Credit arrangements	11	35	(69)%
Amortization of debt costs	8	8	—%
Total gross interest expense	174	239	(27)%
Less: capitalization	(109)	(115)	(5)%
Net interest expense	\$ 65	\$ 124	(48)%

- Interest expense related to our senior notes decreased for the year ended December 31, 2019, as compared to the same period in 2018, as we repurchased \$114 million and \$900 million of our outstanding senior notes in the second half of 2019 and December 2018, respectively. Additionally, S&P and Moody's upgraded our public bond ratings in April and May 2018, respectively, which lowered the interest relates associated with our senior notes due 2020 and 2025 by 50 basis points, starting in July 2018.
- For the year ended December 31, 2019, interest expense related to our credit arrangements decreased, as compared to the same period in 2018, primarily due to the extinguishment of our 2016 term loan and entering into our revolving credit facility in April 2018, which decreased our outstanding borrowing amount, along with the repayment of our revolving credit facility borrowings with a portion of the net proceeds from the Fayetteville Shale sale in December 2018.
- Capitalized interest decreased \$6 million for the year ended December 31, 2019, compared to the same period in 2018, due to the evaluation of natural gas and oil properties over the past twelve months. Capitalized interest increased over the same periods as a percentage of gross interest expense primarily due to a smaller percentage decrease in our unevaluated natural gas and oil properties balance, as compared to the larger percentage decrease in our gross interest expense over the same period, in addition to an increase in our average cost of debt over the past twelve months.

Gain (Loss) on Derivatives

	For the years ended December 31,	
	2019	2018
(in millions)		
Gain (loss) on unsettled derivatives	\$ 94	\$ (24)
Gain (loss) on settled derivatives	180 ⁽¹⁾	(94) ⁽¹⁾
Total gain (loss) on derivatives	\$ 274	\$ (118)

(1) Includes \$1 million of premiums paid related to certain natural gas purchased call options for each of the years ended December 31, 2019 and 2018, which is included in gain (loss) on derivatives on the consolidated statement of operations.

We refer you to Note 6 to the consolidated financial statements included in this Annual Report for additional details about our gain (loss) on derivatives.

Gain (Loss) on Early Extinguishment of Debt

- In 2019, we recorded a gain of \$8 million on early extinguishment of debt as a result of our repurchase at a discount of \$62 million in aggregate principal amount of our outstanding senior notes. See Note 9 to the consolidated financial statements of this Annual Report for more information on our long-term debt.
- In December 2018, we used a portion of the net proceeds from our Fayetteville Shale sale to repurchase \$40 million of our senior notes due January 2020, \$787 million of our senior notes due March 2022 and \$73 million of our senior notes due January 2025. We recognized a loss of \$9 million for the redemption of these senior notes, which included \$2 million of premiums paid.
- Concurrent with the closing of our revolving credit facility in April 2018, we repaid our \$1,191 million 2016 secured term loan balance and recognized a loss of \$8 million on early debt extinguishment on the consolidated statements of operations related to the unamortized debt issuance expense.

Income Taxes

	For the years ended December 31,	
	2019	2018
(in millions except percentages)		
Income tax expense (benefit)	\$ (411)	\$ 1
Effective tax rate	(86)%	0 %

- As of the first quarter of 2019, we had sustained a three-year cumulative level of profitability. Based on this factor and other positive evidence including forecasted income, we concluded that it was more likely than not that the deferred tax assets would be realized and determined that \$522 million of the valuation allowance will be released. As a result, a net tax benefit was recorded during 2019 of \$411 million, which was primarily comprised of a deferred tax benefit of \$522 million related to the valuation allowance release offset by the recognition of deferred tax expense of \$112 million related to taxes on pre-tax income. We expect to retain a valuation allowance of \$87 million related to net operating losses in jurisdictions in which we no longer operate.
- Our low effective income tax rate in 2018 was the result of our recognition of a valuation allowance that reduced the deferred tax asset primarily related to our current net operating loss carryforward, as well as changes to the deferred tax rate enacted under the Tax Reform Act. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

We refer you to Note 11 to the consolidated financial statements included in this Annual Report for additional discussion about our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on funds generated from our operations, our secured revolving credit facility, our cash and cash equivalents balance and capital markets as our primary sources of liquidity. We refer you to Note 9 to the consolidated financial statements included in this Annual Report and the section below under “Credit Arrangements and Financing Activities” for additional discussion of our revolving credit facility. Looking forward to 2020, although we have financial flexibility with our ability to draw on the \$1.8 billion in available liquidity under our revolving credit facility as of December 31, 2019, we remain committed to our capital discipline strategy of investing within our cash flow from operations net of changes in working capital, supplemented by a portion of the remaining net proceeds from the Fayetteville Shale sale realized in December 2018 that in the meantime was used to reduce outstanding debt. See Note 3 to the consolidated financial statements included in this Annual Report for additional discussion of the Fayetteville Shale sale.

In December 2018, we closed on the Fayetteville Shale sale and received net proceeds of approximately \$1,650 million after customary purchase price adjustments. From the net proceeds received, \$914 million was immediately used to repurchase \$900 million of our outstanding senior notes along with related accrued interest and retirement premiums paid, \$201 million was used in late 2018 and early 2019 to repurchase over 44 million shares of our outstanding common stock and the remainder was earmarked to supplement our 2019 and 2020 capital investing programs. Rather than hold these proceeds as cash and cash equivalents during this time, we chose to repurchase or pay down outstanding debt until such time that the sale proceeds would be used to supplement our capital investing program. Accordingly, as our 2020 capital investing program is expected to exceed our cash flow from operations, net of changes in working capital, supplemented by Fayetteville Shale sale proceeds, we plan on drawing no more than \$300 million of the remaining earmarked sale proceeds from our revolving credit facility.

Our cash flow from operating activities is highly dependent upon the sales prices that we receive for our natural gas and liquids production. Natural gas, oil and NGL prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we realize for our production is also influenced by our commodity hedging activities. Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. In 2019, gains on derivatives have offset a large portion of the impact of the recent decline in prices, and we currently have derivative positions in place for portions of our expected 2020, 2021 and 2022 production at prices above current market levels. There can be no assurance that we will be able to add derivative positions to cover the remainder of our expected production at favorable prices. See “Risk Factors” in Item 1A, “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A and Note 6 to the consolidated financial statements included in this Annual Report for further details.

Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to settle the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Our short-term cash flows are also dependent on the timely collection of receivables from our customers and joint interest owners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and joint interest partners could adversely impact our cash flows.

Due to the above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we expect to adjust our discretionary uses of cash depending upon available cash flow. Further, we may from time to time seek to retire, rearrange or amend some or all of our outstanding debt or debt agreements through cash purchases, and/or exchanges, open market purchases, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Credit Arrangements and Financing Activities

In April 2018, we replaced our 2016 credit facility with a new revolving credit facility. The 2018 credit facility has an aggregate maximum revolving credit amount of \$3.5 billion with a current aggregate commitment of \$2.0 billion and a borrowing base (limit on availability) that is redetermined at least each April and October. The 2018 credit facility is secured by substantially all of our assets, including most of our subsidiaries. The permitted lien provisions in the senior note indentures currently limit liens securing indebtedness to the greater of \$2.0 billion or 25% of adjusted consolidated net tangible assets. In October 2019, we entered into an amendment to the 2018 credit facility that, among other things, established the October 2019 borrowing base at \$2.1 billion and extended the maturity date to April 2024. The borrowing base is subject to change based primarily on drilling results, commodity prices, our future derivative position, the level of capital investing and operating costs. As of December 31, 2019, we had \$34 million borrowings on our revolving credit facility and \$172 million in outstanding letters of credit.

As of December 31, 2019, we were in compliance with all of the covenants of our revolving credit facility in all material respects. Our ability to comply with financial covenants is dependent upon the success of our development program and upon factors beyond our control, such as the market prices for natural gas and liquids. We refer you to Note 9 of the consolidated financial statements included in this Annual Report for additional discussion of the covenant requirements of our 2018 revolving credit facility.

The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving credit facility. Although we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet their obligation to us. We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional discussion of our revolving credit facility.

In the second half of 2019, we repurchased \$35 million of our 4.95% Senior Notes due 2025, \$11 million of our 7.50% Senior Notes due 2026 and \$16 million of our 7.75% Senior Notes due 2027, and recognized an \$8 million gain on extinguishment of debt. Additionally, in December 2019, we retired the remaining \$52 million principal of our 4.05% Senior Notes due 2020.

Because of the focused work on refinancing and repayment of our debt during the last three years, only \$247 million, or 11%, of our outstanding debt balance as of December 31, 2019 is scheduled to become due prior to 2025.

At February 25, 2020, we had a long-term issuer credit rating of Ba2 by Moody's, a long-term debt rating of BB by S&P and a long-term issuer default rating of BB by Fitch Ratings. Any upgrades or downgrades in our public debt ratings by Moody's or S&P could decrease or increase our cost of funds, respectively.

Cash Flows

<i>(in millions)</i>	For the years ended December 31,	
	2019	2018
Net cash provided by operating activities	\$ 964	\$ 1,223
Net cash provided by (used in) investing activities	(1,045)	359
Net cash used in financing activities	(115)	(2,297)

Cash Flow from Operations

<i>(in millions)</i>	For the years ended December 31,	
	2019	2018
Net cash provided by operating activities	\$ 964	\$ 1,223
Add: Changes in working capital	(69)	90
Net cash provided by operating activities, net of changes in working capital	895	1,313

- Net cash provided by operating activities decreased 21% or \$259 million for the year ended December 31, 2019, compared to the same period in 2018, primarily due to a decrease in revenues resulting from an 18% decrease in production volumes as a result of the Fayetteville Shale sale in December 2018 and a 6% decrease in our weighted average realized commodity price, including derivatives.
- Net cash generated from operating activities, net of changes in working capital, provided 79% of our cash requirements for capital investments for the year ended December 31, 2019, compared to providing 105% of our cash requirements for capital investments for the same period in 2018. As discussed above, a portion of the Fayetteville Shale sale proceeds was also used to fund the 2019 capital investment program.

Cash Flow from Investing Activities

- Total E&P capital investing decreased \$93 million for the year ended December 31, 2019, compared to the same period in 2018, due to a \$73 million decrease in direct E&P capital investing, a \$14 million decrease in capitalized internal costs and a \$6 million decrease in capitalized interest.
- The decrease in capitalized interest for the year ended December 31, 2019, as compared to the same period in 2018, was primarily due to the evaluation of natural gas and oil properties over the past twelve months.
- Marketing capital investing decreased \$9 million for the year ended December 31, 2019, compared to the same period in 2018, primarily due to the sale of the midstream gathering assets associated with the Fayetteville Shale in December 2018.

<i>(in millions)</i>	For the years ended December 31,	
	2019	2018
Additions to properties and equipment	\$ 1,099	\$ 1,290
Adjustments for capital investments:		
Changes in capital accruals	35	(53)
Other ⁽¹⁾	6	11
Total capital investing	\$ 1,140	\$ 1,248

(1) Includes capitalized non-cash stock-based compensation and costs to retire assets, which are classified as cash used in operating activities.

Capital Investing

<i>(in millions except percentages)</i>	For the years ended December 31,		
	2019	2018	Increase/ (Decrease)
E&P capital investing	\$ 1,138	\$ 1,231	
Marketing capital investing ⁽¹⁾	—	9	
Other capital investing	2	8	
Total capital investing	\$ 1,140	\$ 1,248	(9)%

(1) Included our midstream gathering business in the Fayetteville Shale was sold in December 2018.

<i>(in millions)</i>	For the years ended December 31,	
	2019	2018
E&P Capital Investments by Type:		
Drilling and completions, including workovers	\$ 838	\$ 895
Acquisitions of properties	55	51
Seismic expenditures	3	4
Water infrastructure projects	35	60
Drilling rigs, well services equipment and other	21	15
Capitalized interest and expenses	186	206
Total E&P capital investments	\$ 1,138	\$ 1,231

E&P Capital Investments by Area:

Northeast Appalachia	\$ 365	\$ 422
Southwest Appalachia	710	691
Fayetteville Shale ⁽¹⁾	—	33
Other ⁽²⁾	63	85
Total E&P capital investments	\$ 1,138	\$ 1,231

(1) The Fayetteville Shale assets were sold in December 2018.

(2) Includes \$35 million and \$60 million for the years ended December 31, 2019 and 2018, respectively, related to our water infrastructure project.

Gross Operated Well Count Summary:	For the years ended December 31,	
	2019	2018
Drilled	105	106
Completed	116	119
Wells to sales	113	138

Actual capital expenditure levels may vary significantly from period to period due to many factors, including drilling results, natural gas, oil and NGL prices, industry conditions, the prices and availability of goods and services, and the extent to which properties are acquired or non-strategic assets are sold.

Cash Flow from Financing Activities

For the years ended December 31,

<i>(in millions except percentages)</i>	2019	2018	Increase/ (Decrease)
Debt ⁽¹⁾	\$ 2,242	\$ 2,318	\$ (76)
Equity	\$ 3,246	\$ 2,362	\$ 884
Total debt to capitalization ratio	41 %	50 %	

(1) The decrease in total debt as of December 31, 2019, as compared to December 31, 2018, primarily relates to the repurchase of \$114 of our outstanding senior notes in the second half of 2019, partially offset by a \$34 million increase in our revolving credit facility borrowings.

- Net cash used in financing activities for the year ended December 31, 2019 was \$115 million, compared to net cash used in financing activities of \$2,297 million for the same period in 2018.
- In January 2019, we repurchased approximately 5 million shares of common stock for approximately \$21 million.
- In the second half of 2019, we paid \$54 million on the open market to repurchase \$62 million of our outstanding senior notes at a discount. We recognized a gain on early extinguishment of debt of \$8 million.
- In December 2019, we retired the remaining \$52 million principal of our 4.05% Senior Notes due January 2020.
- In January 2018, we paid \$27 million for a preferred stock dividend declared in the fourth quarter of 2017.
- In April 2018, we fully repaid our \$1,191 million 2016 term loan and replaced it with the 2018 revolving credit facility with a \$2.1 billion borrowing base. We recognized a loss on early extinguishment of debt of \$8 million.
- In December 2018, upon closing of the Fayetteville Shale sale, a portion of the sale proceeds was used to fund tender offers to repurchase \$900 million of our outstanding senior notes. We recognized a loss on early extinguishment of debt of \$9 million, primarily related to the early retirement premiums.
- We also used a portion of the net proceeds from the Fayetteville Shale sale to repurchase 39 million shares of common stock for approximately \$180 million in December 2018.

We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional discussion of our outstanding debt and credit facility.

Working Capital

- We had negative working capital of \$169 million at December 31, 2019, a \$279 million decrease from December 31, 2018, as a decrease of \$236 million in accounts receivable as compared to December 31, 2018, primarily related to the sale of the Fayetteville Shale production in December 2018 and lower commodity prices, a decrease of \$196 million in cash and cash equivalents and a current liability of \$34 million recorded in 2019 related to the implementation of the new lease accounting standard (Topic 842), were only partially offset by a \$102 million increase in the net current market-to-market value of our derivative position and an \$84 million decrease in accounts payable, as compared to December 31, 2018.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2019, our material off-balance sheet arrangements and transactions include operating service arrangements, \$172 million in letters of credit outstanding against our 2018 revolving credit facility and \$55 million in outstanding surety bonds. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to “Contractual Obligations and Contingent Liabilities and Commitments” below for more information on our operating leases.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations as of December 31, 2019, were as follows:

Contractual Obligations:

(in millions)	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
Transportation charges ⁽¹⁾	\$ 8,470	\$ 768	\$ 1,235	\$ 1,169	\$ 1,739	\$ 3,559
Debt	2,262	—	213	34	2,015	—
Interest on debt ⁽²⁾	985	160	317	296	212	—
Operating leases ⁽³⁾	148	33	42	28	29	16
Compression services ⁽⁴⁾	37	13	22	2	—	—
Operating agreements	11	8	3	—	—	—
Purchase obligations	69	69	—	—	—	—
Other obligations ⁽⁵⁾	13	10	3	—	—	—
	\$ 11,995	\$ 1,061	\$ 1,835	\$ 1,529	\$ 3,995	\$ 3,575

- (1) As of December 31, 2019, we had commitments for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems. Of the total \$8.5 billion, \$1.1 billion related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. For further information, we refer you to “Operational Commitments and Contingencies” in Note 10 to the consolidated financial statements included in this Annual Report. This amount also included guarantee obligations of up to \$293 million.

Included in the transportation charges above is \$108 million (due in less than one year) related to certain agreements that remain in the name of our marketing affiliate but are expected to be paid in full by Flywheel Energy Operating, LLC, the purchaser of the Fayetteville Shale assets. Of these amounts, we may be obligated to reimburse Flywheel Energy Operating, LLC, for a portion of volumetric shortfalls during 2020 (up to \$58 million) under these transportation agreements and have currently recorded a \$46 million liability as of December 31, 2019, down from \$88 million recorded at December 31, 2018.

In the first quarter of 2019, we agreed to purchase firm transportation with pipelines in the Appalachian basin starting in 2021 and running through 2032 totaling \$357 million in total contractual commitments of which the seller has agreed to reimburse \$133 million of these commitments.

In February 2020, we were notified that the proposed Constitution pipeline project was cancelled and that we were released from a firm transportation agreement with its sponsor. As of December 31, 2019, we had contractual commitments totaling \$512 million over the next seventeen years related to the Constitution pipeline project that are reflected in the table above as transportation obligations that were pending regulatory approval and/or construction. These amounts are \$6 million within one to three years, \$68 million within three to five years, \$102 million within five to eight years and \$336 million more than eight years forward.

- (2) Interest payments on our senior notes were calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2019. Senior note interest rates were based on our credit ratings as of December 31, 2019.
- (3) Operating leases include costs for compressors, drilling rigs, pressure pumping equipment, office space and other equipment under non-cancelable operating leases expiring through 2029.
- During the second quarter of 2019, we executed an agreement to convey our purchase option in our headquarters office building to a third-party, which closed on the purchase of the building in July 2019. Concurrent with the closing of the building sale, we terminated our existing lease agreement and entered into a new 10-year lease agreement for a smaller portion of the headquarters building in July 2019, resulting in an estimated annual savings of \$7 million to \$8 million.
- (4) As of December 31, 2019, our E&P segment had commitments of approximately \$37 million for compression services associated primarily with our Southwest Appalachia division.
- (5) Our other significant contractual obligations include approximately \$12 million for various information technology support and data subscription agreements.

Future contributions to the pension and postretirement benefit plans are excluded from the table above. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 13 to the consolidated financial statements included in this Annual Report and “Critical Accounting Policies and Estimates” below for additional information.

We refer you to Note 9 to the consolidated financial statements included in this Annual Report for a discussion of the terms of our debt.

We are subject to various litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic incidents, pollution, contamination, encroachment on others’ property or nuisance. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. Management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows, although it is possible that adverse outcomes could have a material adverse effect on our results of operations or cash flows for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the

allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position, results of operations or cash flows.

For further information, we refer you to "Litigation" and "Environmental Risk" in Note 10 to the consolidated financial statements included in this Annual Report.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We evaluate our estimates on an ongoing basis, based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following describes significant judgments and estimates used in the preparation of our consolidated financial statements.

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2019, we had approximately \$1,506 million of costs excluded from our amortization base, all of which related to our properties in the United States. Inclusion of some or all of these costs in our properties in the United States in the future, without adding any associated reserves, could result in non-cash ceiling test impairments.

At December 31, 2019, the ceiling value of our reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of \$2.58 per MMBtu, for West Texas Intermediate oil of \$55.69 per barrel and NGLs of \$11.58 per barrel, adjusted for market differentials. The net book value of our natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2019. We had no derivative positions that were designated for hedge accounting as of December 31, 2019. Although no ceiling test impairment was recorded in 2019, given the fall in commodity prices in 2019 and early 2020 and assuming that commodity prices remain at January 2020 levels for the rest of the first quarter of 2020, we expect a non-cash impairment to our natural gas and oil properties in the first quarter of 2020 ranging from approximately \$400 million to \$600 million, net of tax. Future decreases in commodity prices, increases in costs and/or changes in the balance of costs excluded from amortization and other factors may result in further non-cash impairments to our natural gas and oil properties.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of \$3.10 per MMBtu, West Texas Intermediate oil of \$65.56 per barrel and NGLs of \$17.64 per barrel, adjusted for market differentials, the net book value of our United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2018. We had no derivative positions that were designated for hedge accounting as of December 31, 2018.

A decline in natural gas, oil and NGL prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves. In the past, nearly all of our reserve base was natural gas; therefore changes in oil and NGL prices did not have as significant an impact as natural gas prices on cash flows and reserve quantities. However, with the sale of our Fayetteville Shale assets in 2018 and our strategic shift towards developing our liquids-rich assets in recent years, our reserve base as of December 31, 2019 was approximately 68% natural gas, 29% NGLs and 3% oil. Therefore, NGL and oil pricing will have a more significant impact on the cash flows and quantity of reserves going forward. Our standardized measure and reserve quantities as of December 31, 2019, were \$3.7 billion and 12.7 Tcfe, respectively.

Natural gas, oil and NGL reserves cannot be measured exactly. Our estimate of natural gas, oil and NGL reserves requires extensive judgments of reservoir engineering data and projections of costs that will be incurred in developing and producing reserves and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team for that property. The reservoir engineering and financial data included in these estimates are reviewed by senior engineers, who are not part of the asset management teams, and by our Director of Reserves, who is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Director of Reserves has more than 25 years of experience in petroleum engineering, including the estimation of natural gas and oil reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2018, our Director of Reserves served in various reservoir engineering roles for EP Energy Company, El Paso Corporation, Cabot Oil & Gas Corporation, Schlumberger and H.J. Gruy & Associates, and is a member of the Society of Petroleum Engineers. He reports to our Executive Vice President and Chief Operating Officer, who has more than 31 years of experience in petroleum engineering including the estimation of natural gas, oil and NGL reserves in multiple basins in the United States, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining Southwestern in 2017, our Chief Operating Officer served in various engineering and leadership roles for EP Energy Corporation, El Paso Corporation, ARCO Oil and Gas Company, Burlington Resources and Peoples Energy Production, and is a member of the Society of Petroleum Engineers.

We engage NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates as discussed in more detail below. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the two technical persons primarily responsible for auditing our proved reserves estimates (1) have over 38 years and over 17 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 28 years and over 17 years of experience in the estimation and evaluation of reserves, respectively; (3) each has a college degree; (4) each is a Licensed Professional Geoscientist in the State of Texas or a Licensed Professional Engineer in the State of Texas; (5) each 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; and (6) each is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. The financial data included in the reserve estimates is also separately reviewed by our accounting staff. Our proved reserves estimates, as internally reviewed and audited by NSAI, are submitted for review and approval to our President and Chief Executive Officer. Finally, upon his approval, NSAI reports the results of its reserve audit to the Board of Directors, with whom final authority over the estimates of our proved reserves rests. A copy of NSAI's report has been filed as Exhibit 99.1 to this Annual Report.

Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves accounted for 50% of our total reserve base as of December 31, 2019. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production volumes and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to "Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material changes to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A, "Risk Factors," of Part I of this Annual Report for a more detailed discussion of these uncertainties, risks and other factors.

In conducting its audit, the engineers and geologists of NSAI study our major properties in detail and independently develop reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 99% of the present worth of the company's total proved reserves. NSAI's audit process consists of sorting all fields by descending present value order and selecting the fields from highest value to descending value until the selected fields account for more than 80% of the present worth of our reserves. The fields included in approximately the top 99% present value as of December 31, 2019, accounted for approximately 99% of our total proved reserves and approximately 100% of our proved undeveloped reserves. In the conduct of its audit, NSAI did not independently verify the data we provided to them with respect to ownership interests, natural gas, oil and NGL production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. NSAI has advised us that if, in the course of its audit, something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved any questions relating thereto or had independently verified such information or data. On February 7, 2020, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2019 stating that our estimated proved natural gas, oil and NGL reserves are, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Assets and liabilities held for sale are subject to an assessment of fair value which includes many key valuation estimates, inputs and assumptions including but not limited to: production forecasts, pricing, basis differentials, operating and general and administrative expense forecasts, future development costs, discount rate determination and tax inputs. In the third quarter of 2018, we recognized certain assets and liabilities as held for sale related to the Fayetteville Shale sale requiring a comparison of their respective carrying cost and fair value less costs to sell. Our full cost pool assets were excluded from held for sale accounting treatment as they are governed by SEC Regulation S-X Rule 4-10. The fair value of our gathering assets to be sold was estimated using an estimated discounted cash flow model along with market assumptions. The assumptions used in the calculation of estimated discounted cash flows included future commodity prices, projections of estimated quantities of natural gas reserves, operating costs, projections of future rates of production, inflation factors and risk-adjusted discount rates. We believe the assumptions used were reasonable.

Under full cost accounting rules, sales of oil and gas properties, whether or not being amortized currently, shall be accounted for as a reduction of the full cost pool, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For instance, a significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of the reserve quantities of a given cost center. Judgments are required around the determination of whether a divestment is deemed significant. Such judgments include an assessment of the of the reserve quantities sold as compared to total reserve quantities and other qualitative and quantitative assessments of the relationship between capitalized costs and proved reserves. We did not recognize a gain or loss on the sale of our oil and gas properties as the divestment was deemed not significant. Please refer to Note 3 to the consolidated financial statements included in this Annual Report for further detail.

Derivatives and Risk Management

We use fixed price swap agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of certain commodities and interest rates. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. We actively monitor the credit status of our counterparties based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. In both 2019 and 2018, we financially protected 69% of our total production with derivatives. The primary risks related to our derivative contracts are the volatility in market prices and basis differentials for our production. However, the market price risk is generally offset by the gain or loss recognized upon the related transaction that is financially protected.

All derivatives are recognized in the balance sheet as either an asset or a liability as measured at fair value other than transactions for which the normal purchase/normal sale exception is applied. Certain criteria must be satisfied for derivative financial instruments to be designated for hedge accounting. Accounting guidance for qualifying hedges allows an unsettled derivative's unrealized gains and losses to be recorded in either earnings or as a component of other comprehensive income until settled. In the period of settlement, we recognize the gains and losses from these qualifying hedges in gas sales revenues. The ineffective portion of those fixed price swaps was recognized in earnings. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statement of operations reflects the gains and losses on both settled and unsettled derivatives. We calculate gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period.

As of December 31, 2019, none of our derivative contracts were designated for hedge accounting treatment. Changes in the fair value of unsettled derivatives that were not designated for hedge accounting treatment are recorded in gain (loss) on derivatives. See Note 6 to the consolidated financial statements included in this Annual Report for more information on our derivative position at December 31, 2019.

Future market price volatility could create significant changes to the derivative positions recorded in our consolidated financial statements. We refer you to “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A of Part II of this Annual Report for additional information regarding our hedging activities.

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 13 to the consolidated financial statements included in this Annual Report for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2019 benefit obligation and periodic benefit cost to be recorded in 2020, the initial discount rate assumed is 3.70%. This compares to an initial discount rate of 4.35% for the benefit obligation and periodic benefit cost recorded in 2019. For the 2020 periodic benefit cost, the expected return assumed decreased to 6.50%, from 7.00% in 2019.

Using the assumed rates discussed above, we recorded total benefit cost of \$15 million in 2019 related to our pension and other postretirement benefit plans. Due to the significance of the discount rate and expected long-term rate of return, the following sensitivity analysis demonstrates the effect that a 0.5% change in those assumptions would have had on our 2019 pension expense:

<i>(in millions)</i>	Increase (Decrease) of Annual Pension Expense	
	0.5% Increase	0.5% Decrease
Discount rate	\$ (1)	\$ 1
Expected long-term rate of return	\$ —	\$ —

As of December 31, 2019, we recognized a liability of \$43 million, compared to \$47 million at December 31, 2018, related to our pension and other postretirement benefit plans. During 2019, we also made cash contributions totaling \$14 million to fund our pension and other postretirement benefit plans.

Stock-Based Compensation

We account for stock-based compensation transactions using a fair value method and recognize an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalize the cost into natural gas and oil properties included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of our natural gas and oil properties. We use models to determine fair value of stock-based compensation, which requires significant judgment with respect to forfeitures, volatility and other factors.

Our stock-based compensation is classified as either an equity award or a liability award in accordance with generally accepted accounting principles. The fair value of an equity-classified award is determined at the grant date and is amortized on a straight-line basis over the vesting life of the award. The fair-value of a liability-classified award is determined on a quarterly basis through the final vesting date and is amortized based on the current fair value of the award and the percentage of vesting period incurred to date.

New Accounting Standards

Refer to Note 1 to the consolidated financial statements included in this Annual Report for further discussion of our significant accounting policies and for discussion of accounting standards that have been implemented in this report, along with a discussion of relevant accounting standards that are pending adoption.

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in

such forward-looking statements, they are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Annual Report identified by words such as “anticipate,” “intend,” “plan,” “project,” “estimate,” “continue,” “potential,” “should,” “could,” “may,” “will,” “objective,” “guidance,” “outlook,” “effort,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “forecast,” “target” or similar words.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for natural gas, oil and NGLs (including regional basis differentials);
- our ability to fund our planned capital investments;
- a change in our credit rating, an increase in interest rates and any adverse impacts from the discontinuation of the London Interbank Offered Rate (“LIBOR”);
- the extent to which lower commodity prices impact our ability to service or refinance our existing debt;
- the impact of volatility in the financial markets or other global economic factors, including the possible impact of the coronavirus (COVID-19);
- difficulties in appropriately allocating capital and resources among our strategic opportunities;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to maintain leases that may expire if production is not established or profitably maintained;
- our ability to realize the expected benefits from acquisitions;
- our ability to transport our production to the most favorable markets or at all;
- availability and costs of personnel and of products and services provided by third parties;
- the impact of government regulation, including changes in law, the ability to obtain and maintain permits, any increase in severance or similar taxes, and legislation or regulation relating to hydraulic fracturing, climate and over-the-counter derivatives;
- the impact of the adverse outcome of any material litigation against us or judicial decisions that affect us or our industry generally;
- the effects of weather;
- increased competition;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the SEC.

Should one or more of the risks or uncertainties described above or elsewhere in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as service costs and credit risk concentrations. We use fixed price swap agreements, options, basis swaps and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas, oil and certain NGLs along with interest rates. Our Board of Directors has approved risk management policies to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is also overseen by our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our exposure to concentrations of credit risk consists primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our purchasers and their dispersion across geographic areas. No single purchaser accounted for greater than 10% of revenues during the year ended December 31, 2019. For the year ended December 31, 2018, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% of total natural gas, oil and NGL sales. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production. See “Commodities Risk” below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of December 31, 2019, we had approximately \$2.2 billion of outstanding senior notes with a weighted average interest rate of 6.71%, and \$34 million of borrowings under our revolving credit facility. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates. At December 31, 2019, we had a long-term issuer credit rating of Ba2 by Moody’s, a long-term debt rating of BB by S&P and a long-term debt issuer default rating of BB by Fitch Ratings. Any upgrades or downgrades in our public debt ratings by Moody’s or S&P could decrease or increase our cost of funds, respectively.

<i>(in millions except percentages)</i>	Expected Maturity Date						Total
	2020	2021	2022	2023	2024	Thereafter	
Fixed rate payments ⁽¹⁾	\$ —	\$ —	\$ 213	\$ —	\$ —	\$ 2,015	\$ 2,228
Weighted average interest rate	—%	—%	4.10%	—%	—%	6.98%	6.71%
Variable rate payments ⁽¹⁾	\$ —	\$ —	\$ —	\$ —	\$ 34	\$ —	\$ 34
Weighted average interest rate	—%	—%	—%	—%	4.31%	—%	4.31%

(1) Excludes unamortized debt issuance costs and debt discounts.

Commodities Risk

We use over-the-counter fixed price swap agreements and options to protect sales of our production against the inherent risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps) and transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps).

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for our production. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the production that is financially protected. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major banks and integrated energy companies that management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, we cannot be certain that we will not experience such losses in the future. We refer you to Note 6 of the consolidated financial statements included in this Annual Report for additional details about our derivative instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	<u>Page</u>
Management’s Report on Internal Control Over Financial Reporting	72
Report of Independent Registered Public Accounting Firm	72
Consolidated Statements of Operations for the three years ended December 31, 2019	74
Consolidated Statements of Comprehensive Income (Loss) for the three years ended December 31, 2019	75
Consolidated Balance Sheets as of December 31, 2019 and 2018	76
Consolidated Statements of Cash Flows for the three years ended December 31, 2019	77
Consolidated Statements of Changes in Equity for the three years ended December 31, 2019	78
Notes to Consolidated Financial Statements	79
Note 1 – Organization and Summary of Significant Accounting Policies	79
Note 2 – Restructuring Charges	84
Note 3 – Divestitures	85
Note 4 – Leases	86
Note 5 – Revenue Recognition	88
Note 6 – Derivatives and Risk Management	91
Note 7 – Reclassifications from Accumulated Other Comprehensive Income (Loss)	98
Note 8 – Fair Value Measurements	98
Note 9 – Debt	102
Note 10 – Commitments and Contingencies	104
Note 11 – Income Taxes	106
Note 12 – Asset Retirement Obligation	108
Note 13 – Retirement and Employee Benefit Plans	109
Note 14 – Stock-Based Compensation	114
Note 15 – Segment Information	118
Note 16 – Condensed Consolidating Financial Statements	120
Note 17 – Subsequent Events	127
Supplemental Quarterly Results	127
Supplemental Oil and Gas Disclosures	128

Management’s Report on Internal Control Over Financial Reporting

It is the responsibility of the management of Southwestern Energy Company to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management has assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2019, utilizing the Committee of Sponsoring Organizations of the Treadway Commission’s Internal Control – Integrated Framework (2013).

Based on this evaluation, management has concluded the Company’s internal control over financial reporting was effective as of December 31, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Southwestern Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Southwestern Energy Company and its subsidiaries (the “Company”) as of December 31, 2019 and 2018, and the related consolidated statements of operations, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company’s internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

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

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

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

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions

of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

Critical Audit Matters

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

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

The Company's consolidated property and equipment, net balance was \$5,267 million as of December 31, 2019, and depreciation, depletion, and amortization (DD&A) expense for the year ended December 31, 2019 was \$471 million, both of which substantially relate to proved natural gas and oil properties. As described in Note 1 to the consolidated financial statements, the Company utilizes the full cost method of accounting for its natural gas and oil producing properties. Under this method, all capitalized costs are amortized over the estimated lives of the properties using the unit-of-production method based on proved natural gas, oil and NGL reserves. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10%. In 2019, the Company did not have any ceiling test impairments on its proved natural gas and oil properties. As disclosed by management, estimates of natural gas, oil and NGL reserves require extensive judgments of reservoir engineering data and projections of costs that will be incurred in developing and producing reserves. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production volumes and the costs that will be incurred in developing and producing the reserves. The estimates of natural gas, oil and NGL reserves have been developed by specialists, specifically reservoir engineers.

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

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved natural gas, oil and NGL reserves, the calculation of the full cost ceiling impairment test, and the calculation of DD&A expense. These procedures also included, among others, evaluating the significant assumptions used by management in developing these estimates, including future production volumes, testing the full cost ceiling impairment test calculation, and testing the unit-of-production rate used to calculate DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved natural gas, oil and NGL reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialists' findings.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 27, 2020

We have served as the Company's auditor since 2002.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

For the years ended December 31,

(in millions, except share/per share amounts)

	2019	2018	2017
Operating Revenues:			
Gas sales	\$ 1,241	\$ 1,998	\$ 1,793
Oil sales	223	196	102
NGL sales	274	352	206
Marketing	1,297	1,222	972
Gas gathering	—	89	126
Other	3	5	4
	<u>3,038</u>	<u>3,862</u>	<u>3,203</u>
Operating Costs and Expenses:			
Marketing purchases	1,320	1,229	976
Operating expenses	720	785	671
General and administrative expenses	166	209	233
(Gain) loss on sale of operating assets, net	2	(17)	(6)
Restructuring charges	11	39	—
Depreciation, depletion and amortization	471	560	504
Impairments	16	171	—
Taxes, other than income taxes	62	89	94
	<u>2,768</u>	<u>3,065</u>	<u>2,472</u>
	<u>270</u>	<u>797</u>	<u>731</u>
Operating Income			
Interest Expense:			
Interest on debt	166	231	239
Other interest charges	8	8	9
Interest capitalized	(109)	(115)	(113)
	<u>65</u>	<u>124</u>	<u>135</u>
Gain (Loss) on Derivatives	274	(118)	422
Gain (Loss) on Early Extinguishment of Debt	8	(17)	(70)
Other Income (Loss), Net	(7)	—	5
	<u>480</u>	<u>538</u>	<u>953</u>
Income Before Income Taxes			
Provision (Benefit) for Income Taxes			
Current	(2)	1	(22)
Deferred	(409)	—	(71)
	<u>(411)</u>	<u>1</u>	<u>(93)</u>
Net Income	<u>\$ 891</u>	<u>\$ 537</u>	<u>\$ 1,046</u>
Mandatory convertible preferred stock dividend	—	—	108
Participating securities – mandatory convertible preferred stock	—	2	123
Net Income Attributable to Common Stock	<u>\$ 891</u>	<u>\$ 535</u>	<u>\$ 815</u>
Earnings Per Common Share:			
Basic	<u>\$ 1.65</u>	<u>\$ 0.93</u>	<u>\$ 1.64</u>
Diluted	<u>\$ 1.65</u>	<u>\$ 0.93</u>	<u>\$ 1.63</u>
Weighted Average Common Shares Outstanding:			
Basic	<u>539,345,343</u>	<u>574,631,756</u>	<u>498,264,321</u>
Diluted	<u>540,382,914</u>	<u>576,642,808</u>	<u>500,804,297</u>

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

<i>(in millions)</i>	For the years ended December 31,		
	2019	2018 ⁽¹⁾	2017 ⁽¹⁾
Net income	\$ 891	\$ 537	\$ 1,046
Change in value of pension and other postretirement liabilities:			
Amortization of prior service cost and net loss, including loss on settlements and curtailments included in net periodic pension cost ⁽²⁾	8	10	2
Net actuarial loss incurred in period ⁽³⁾	(5)	(2)	(13)
Total change in value of pension and postretirement liabilities	3	8	(11)
Change in currency translation adjustment	—	—	6
Comprehensive income	\$ 894	\$ 545	\$ 1,041

(1) In 2018 and 2017, deferred tax activity incurred in other comprehensive income was offset by a valuation allowance.

(2) Net of \$2 million in taxes for the year ended December 31, 2019.

(3) Net of (\$1) million in taxes for the year ended December 31, 2019.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
ASSETS		
<i>(in millions, except share amounts)</i>		
Current assets:		
Cash and cash equivalents	\$ 5	\$ 201
Accounts receivable, net	345	581
Derivative assets	278	130
Other current assets	51	44
Total current assets	<u>679</u>	<u>956</u>
Natural gas and oil properties, using the full cost method, including \$1,506 million as of December 31, 2019 and \$1,755 million as of December 31, 2018 excluded from amortization	25,250	24,180
Other	520	525
Less: Accumulated depreciation, depletion and amortization	<u>(20,503)</u>	<u>(20,049)</u>
Total property and equipment, net	5,267	4,656
Operating lease assets	159	—
Deferred tax assets	407	—
Other long-term assets	205	185
Total long-term assets	<u>771</u>	<u>185</u>
TOTAL ASSETS	<u>\$ 6,717</u>	<u>\$ 5,797</u>
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 525	\$ 609
Taxes payable	59	58
Interest payable	51	52
Derivative liabilities	125	79
Current operating lease liabilities	34	—
Other current liabilities	54	48
Total current liabilities	<u>848</u>	<u>846</u>
Long-term debt	2,242	2,318
Long-term operating lease liabilities	119	—
Pension and other postretirement liabilities	43	46
Other long-term liabilities	219	225
Total long-term liabilities	<u>2,623</u>	<u>2,589</u>
Commitments and contingencies (Note 10)		
Equity:		
Common stock, \$0.01 par value; 1,250,000,000 shares authorized; issued 585,555,923 shares as of December 31, 2019 and 585,407,107 as of December 31, 2018	6	6
Additional paid-in capital	4,726	4,715
Accumulated deficit	(1,251)	(2,142)
Accumulated other comprehensive loss	(33)	(36)
Common stock in treasury, 44,353,224 shares as of December 31, 2019 and 39,092,537 shares as of December 31, 2018	(202)	(181)
Total equity	<u>3,246</u>	<u>2,362</u>
TOTAL LIABILITIES AND EQUITY	<u>\$ 6,717</u>	<u>\$ 5,797</u>

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

<i>(in millions)</i>	For the years ended December 31,		
	2019	2018	2017
Cash Flows From Operating Activities:			
Net income	\$ 891	\$ 537	\$ 1,046
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	471	560	504
Amortization of debt issuance costs	8	8	9
Impairments	16	171	—
Deferred income taxes	(409)	—	(71)
(Gain) loss on derivatives, unsettled	(94)	24	(451)
Stock-based compensation	8	14	24
(Gain) loss on early extinguishment of debt	(8)	17	70
(Gain) loss on sale of assets, net	2	(17)	(6)
Other	10	(1)	13
Change in assets and liabilities:			
Accounts receivable	234	(153)	(65)
Accounts payable	(141)	65	48
Taxes payable	—	2	4
Interest payable	—	(10)	(2)
Inventories	(7)	(13)	(1)
Other assets and liabilities	(17)	19	(25)
Net cash provided by operating activities	<u>964</u>	<u>1,223</u>	<u>1,097</u>
Cash Flows From Investing Activities:			
Capital investments	(1,099)	(1,290)	(1,268)
Proceeds from sale of property and equipment	54	1,643	10
Other	—	6	6
Net cash provided by (used in) investing activities	<u>(1,045)</u>	<u>359</u>	<u>(1,252)</u>
Cash Flows From Financing Activities:			
Payments on current portion of long-term debt	(52)	—	(328)
Payments on long-term debt	(54)	(2,095)	(1,139)
Payments on revolving credit facility	(532)	(1,983)	—
Borrowings under revolving credit facility	566	1,983	—
Change in bank drafts outstanding	(19)	17	9
Proceeds from issuance of long-term debt	—	—	1,150
Debt issuance costs	(3)	(9)	(24)
Purchase of treasury stock	(21)	(180)	—
Preferred stock dividend	—	(27)	(16)
Cash paid for tax withholding	(1)	(3)	(2)
Other	1	—	(2)
Net cash used in financing activities	<u>(115)</u>	<u>(2,297)</u>	<u>(352)</u>
Decrease in cash and cash equivalents	(196)	(715)	(507)
Cash and cash equivalents at beginning of year	201	916	1,423
Cash and cash equivalents at end of year	<u>\$ 5</u>	<u>\$ 201</u>	<u>\$ 916</u>

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

<i>(in millions, except share amounts)</i>	Common Stock		Preferred Stock	Additional Paid-In Capital	Accumulated Deficit ⁽¹⁾	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury		Total
	Shares Issued	Amount	Shares Issued				Shares	Amount	
Balance at December 31, 2016	495,248,369	\$ 5	1,725,000	\$ 4,677	\$ (3,725)	\$ (39)	31,269	\$ (1)	\$ 917
Comprehensive income									
Net income	—	—	—	—	1,046	—	—	—	1,046
Other comprehensive loss	—	—	—	—	—	(5)	—	—	(5)
Total comprehensive income	—	—	—	—	—	—	—	—	1,041
Stock-based compensation	—	—	—	38	—	—	—	—	38
Preferred stock dividend	12,791,716	—	—	(16)	—	—	—	—	(16)
Issuance of restricted stock	5,055,208	—	—	—	—	—	—	—	—
Cancellation of restricted stock	(742,028)	—	—	—	—	—	—	—	—
Performance units vested	121,208	—	—	—	—	—	—	—	—
Issuance of stock awards	72	—	—	—	—	—	—	—	—
Tax withholding – stock compensation	(340,234)	—	—	(1)	—	—	—	—	(1)
Balance at December 31, 2017	512,134,311	\$ 5	1,725,000	\$ 4,698	\$ (2,679)	\$ (44)	31,269	\$ (1)	\$ 1,979
Comprehensive income									
Net income	—	—	—	—	537	—	—	—	537
Other comprehensive income	—	—	—	—	—	8	—	—	8
Total comprehensive income	—	—	—	—	—	—	—	—	545
Stock-based compensation	—	—	—	21	—	—	—	—	21
Conversion of preferred stock	74,998,614	1	(1,725,000)	(1)	—	—	—	—	—
Issuance of restricted stock	349,562	—	—	—	—	—	—	—	—
Cancellation of restricted stock	(1,804,122)	—	—	—	—	—	—	—	—
Performance units vested	214,866	—	—	—	—	—	—	—	—
Treasury stock	—	—	—	—	—	—	39,061,268	(180)	(180)
Tax withholding – stock compensation	(486,124)	—	—	(3)	—	—	—	—	(3)
Balance at December 31, 2018	585,407,107	\$ 6	—	\$ 4,715	\$ (2,142)	\$ (36)	39,092,537	\$ (181)	\$ 2,362
Comprehensive income									
Net income	—	—	—	—	891	—	—	—	891
Other comprehensive income	—	—	—	—	—	3	—	—	3
Total comprehensive income	—	—	—	—	—	—	—	—	894
Stock-based compensation	—	—	—	12	—	—	—	—	12
Issuance of restricted stock	236,978	—	—	—	—	—	—	—	—
Cancellation of restricted stock	(239,571)	—	—	—	—	—	—	—	—
Performance units vested	535,802	—	—	—	—	—	—	—	—
Treasury stock	—	—	—	—	—	—	5,260,687	(21)	(21)
Tax withholding – stock compensation	(384,393)	—	—	(1)	—	—	—	—	(1)
Balance at December 31, 2019	585,555,923	\$ 6	—	\$ 4,726	\$ (1,251)	\$ (33)	44,353,224	\$ (202)	\$ 3,246

(1) Includes a net cumulative-effect adjustment of \$59 million related to the recognition of previously unrecognized windfall tax benefits resulting from the adoption of ASU 2016-9 as of the beginning of 2017. This adjustment increased net deferred tax assets and the related income tax valuation allowance by the same amount.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Southwestern Energy Company (including its subsidiaries, collectively “Southwestern” or the “Company”) is an independent energy company engaged in natural gas, oil and NGLs exploration, development and production (“E&P”). The Company is also focused on creating and capturing additional value through its marketing business (“Marketing”), which was previously referred to as “Midstream” when it included the operations of gathering systems. Southwestern conducts most of its business through subsidiaries and operates principally in two segments: E&P and Marketing. The Company’s historical financial and operating results include its Fayetteville Shale E&P and related midstream gathering businesses, which were sold in early December 2018 (“the Fayetteville Shale sale”). The sale is discussed in further detail in Note 3.

E&P. Southwestern’s primary business is the exploration for and production of natural gas, oil and NGLs, with ongoing operations focused on the development of unconventional natural gas and oil reservoirs located in Pennsylvania and West Virginia. The Company’s operations in northeast Pennsylvania, herein referred to as “Northeast Appalachia,” are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Operations in West Virginia and southwest Pennsylvania, herein referred to as “Southwest Appalachia,” are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, Southwestern refers to its properties located in Pennsylvania and West Virginia as “Appalachia.” The Company also operates drilling rigs located in Pennsylvania and West Virginia, and provides oilfield products and services, principally serving the Company’s E&P operations through vertical integration.

Marketing. Southwestern’s marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil and NGLs primarily produced in its E&P operations.

Basis of Presentation

The consolidated financial statements included in this Annual Report present the Company’s financial position, results of operations and cash flows for the periods presented in accordance with accounting principles generally accepted in the United States (“GAAP”). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company evaluates subsequent events through the date the financial statements are issued.

Principles of Consolidation

The consolidated financial statements include the accounts of Southwestern and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

In 2015, the Company purchased an 86% ownership in a limited partnership that owns and operates a gathering system in Northeast Appalachia. Because the Company owns a controlling interest in the partnership, the operating and financial results are consolidated with the Company’s E&P segment results. The minority partner’s share of the partnership activity is reported in retained earnings in the consolidated financial statements. Net income attributable to noncontrolling interest for the years ended December 31, 2019, 2018 and 2017 was insignificant.

Major Customers

The Company sells the vast majority of its E&P natural gas, oil and NGL production to third-party customers through its marketing subsidiary. In 2019, no single customer accounted for 10% or greater of total sales. For the years ended December 31, 2018 and 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% and 10.3%, respectively, of total natural gas, oil and NGL sales. The Company believes that the loss of a major customer would not have a material adverse effect on its ability to sell its natural gas, oil and NGL production because alternative purchasers are available.

Cash and Cash Equivalents

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk as the Company monitors the credit status of the financial

institutions holding its cash and marketable securities. The following table presents a summary of cash and cash equivalents as of December 31, 2019, and December 31, 2018:

<i>(in millions)</i>	<u>December 31, 2019</u>	December 31, 2018
Cash	\$ 5	\$ 32
Marketable securities ⁽¹⁾	—	169
Total	<u>\$ 5</u>	<u>\$ 201</u>

(1) Consists of government stable value money market funds.

Certain of the Company's cash accounts are zero-balance controlled disbursement accounts. The Company presents the outstanding checks written against these zero-balance accounts as a component of accounts payable in the accompanying consolidated balance sheets. Outstanding checks included as a component of accounts payable totaled \$15 million and \$34 million as of December 31, 2019 and 2018, respectively.

Property, Depreciation, Depletion and Amortization

Natural Gas and Oil Properties. The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities, are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure). Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives designated for hedge accounting, to calculate the ceiling value of their reserves. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

Costs associated with unevaluated properties are excluded from the amortization base until the properties are evaluated or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from the amortization base. Leasehold costs are either transferred to the amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. The Company's decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves judgment and may be subject to changes over time based on several factors, including drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2019, the Company had a total of \$1,506 million of costs excluded from the amortization base, all of which related to its properties in the United States. Inclusion of some or all of these costs in the Company's United States properties in the future, without adding any associated reserves, could result in additional non-cash ceiling test impairments.

At December 31, 2019, using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of \$2.58 per MMBtu, West Texas Intermediate oil of \$55.69 per barrel and NGLs of \$11.58 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties was \$218 million below the ceiling amount and therefore did not result in a ceiling test impairment at December 31, 2019. Given the fall in commodity prices in 2019 and early 2020, the Company expects some non-cash impairment of its assets will likely occur as early as the first quarter of 2020. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2019.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of \$3.10 per MMBtu, West Texas Intermediate oil of \$65.56 per barrel and NGLs of \$17.64 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2018. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2018.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of \$2.98 per MMBtu, West Texas Intermediate oil of \$47.79 per barrel and NGLs of \$14.41 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2017. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2017.

Gathering Systems. The Company's investment in gathering systems was primarily in a system serving its Fayetteville Shale operations in Arkansas. These assets were included in the Fayetteville Shale sale that closed in December 2018.

Capitalized Interest. Interest is capitalized on the cost of unevaluated natural gas and oil properties that are excluded from amortization.

Asset Retirement Obligations. Natural gas and oil properties require expenditures to plug and abandon the wells and reclaim the associated pads and other supporting infrastructure when the wells are no longer producing. An asset retirement obligation associated with the retirement of a tangible long-lived asset such as oil and gas properties is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Impairment of Long-Lived Assets. The Company's non-full cost pool assets include water facilities, gathering systems, technology infrastructure, land, buildings and other equipment with useful lives that range from 3 to 30 years. The carrying value of non-full cost pool long-lived assets is evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable. Should an impairment exist, the impairment loss would be measured as the amount that the asset's carrying value exceeds its fair value. For the year ended December 31, 2019, the Company recognized non-cash impairments of \$16 million for non-core assets.

In accordance with accounting guidance for Property, Plant and Equipment, assets held for sale are measured at the lower of carrying value or fair value less costs to sell. This accounting guidance does not apply to the Company's full cost pool assets, which are governed under SEC Regulation S-X 4-10, and thus were not classified as held for sale. Because the assets excluding the full cost pool met the criteria for held for sale accounting in the third quarter of 2018 due to their inclusion in the Fayetteville Shale sale, the Company determined the carrying value of certain non-full cost pool assets exceeded the fair value less costs to sell. As a result, a non-cash impairment charge of \$160 million was recorded for the year ended December 31, 2018, of which \$145 million related to midstream gathering assets held for sale and \$15 million related to E&P assets held for sale. Separately, the Company recorded an \$11 million non-cash impairment of other non-core assets that were not included in the Fayetteville Shale sale, for the year ended December 31, 2018.

Intangible Assets. The carrying value of intangible assets are evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable. Intangible assets are amortized over their useful life. At December 31, 2019 and 2018, the Company had \$56 million and \$65 million, respectively, in marketing-related intangible assets that were included in Other long-term assets on the consolidated balance sheets. The Company amortized \$9 million of its marketing-related intangible asset in each of the years ended December 31, 2019, 2018 and 2017, and expects to amortize \$9 million in 2020, \$8 million in 2021 and \$5 million for the three years thereafter.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate expected to be in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes. 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 accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties. The Company recognizes penalties and interest related to uncertain tax positions within the provision (benefit) for income taxes line in the accompanying consolidated statements of operations. Additional information regarding uncertain tax positions along with the impact of the Tax Reform Act can be found in Note 11.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage defined commodity price risks and does not use them for speculative trading purposes. The Company uses derivative instruments to financially protect sales of natural gas, oil and NGLs. In addition, the Company uses interest rate swaps to manage exposure to unfavorable interest rate changes. Since the Company does not designate its derivatives for hedge accounting treatment, gains and losses resulting from the settlement of derivative contracts have been recognized in gain (loss) on derivatives in the consolidated statements of operations when the contracts expire and the related physical transactions of the underlying commodity are settled. Additionally, changes in the fair value of the unsettled portion of derivative contracts are also recognized in gain (loss) on derivatives in the consolidated statement of operations. See Note 6 and Note 8 for a discussion of the Company's hedging activities.

Earnings Per Share

Basic earnings per common share is computed by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during the reportable period. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding: the incremental shares that would have been outstanding assuming the exercise of dilutive stock options, the vesting of unvested restricted shares of common stock, performance units and the assumed conversion of mandatory convertible preferred stock. An antidilutive impact is an increase in earnings per share resulting from the conversion, exercise, or contingent issuance of certain securities.

In January 2015, the Company issued 34,500,000 depositary shares that entitled the holder to a proportional fractional interest in the rights and preferences of the mandatory convertible preferred stock, including conversion, dividend, liquidation and voting rights. The mandatory convertible preferred stock had the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and, therefore, was considered a participating security. Accordingly, it has been included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, earnings are allocated to participating securities based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so. In January 2018, all outstanding shares of mandatory convertible preferred stock were converted to 74,998,614 shares of the Company's common stock. The Company paid its last dividend payment of approximately \$27 million associated with the depositary shares in January 2018.

The Company declared dividends on its mandatory convertible preferred stock in the first, second and third quarters of 2017 that were settled partially in common stock for a total of 10,040,306 shares.

As part of the Company's share repurchase program, the Company paid approximately \$180 million to repurchase 39,061,268 shares of its outstanding common stock in 2018 and paid approximately \$21 million to repurchase 5,260,687 shares in 2019, which are included in the Company's treasury stock.

The following table presents the computation of earnings per share for the years ended December 31, 2019, 2018 and 2017:

	For the years ended December 31,		
	2019	2018	2017
<i>(in millions, except share/per share amounts)</i>			
Net income	\$ 891	\$ 537	\$ 1,046
Mandatory convertible preferred stock dividend	—	—	108
Participating securities – mandatory convertible preferred stock	—	2	123
Net income attributable to common stock	<u>\$ 891</u>	<u>\$ 535</u>	<u>\$ 815</u>
Number of common shares:			
Weighted average outstanding	539,345,343	574,631,756	498,264,321
Issued upon assumed exercise of outstanding stock options	—	—	—
Effect of issuance of non-vested restricted common stock	361,380	698,103	1,061,056
Effect of issuance of non-vested performance units	676,191	1,312,949	1,478,920
Weighted average and potential dilutive outstanding	<u>540,382,914</u>	<u>576,642,808</u>	<u>500,804,297</u>
Earnings per common share:			
Basic	\$ 1.65	\$ 0.93	\$ 1.64
Diluted	\$ 1.65	\$ 0.93	\$ 1.63

The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the years ended December 31, 2019, 2018 and 2017, as they would have had an antidilutive effect:

	For the years ended December 31,		
	2019	2018	2017
Unexercised stock options	5,078,253	5,909,082	116,717
Unvested share-based payment	1,728,264	3,692,794	5,361,849
Performance units	271,268	642,568	765,689
Mandatory convertible preferred stock	—	2,465,708	74,999,895
Total	7,077,785	12,710,152	81,244,150

Supplemental Disclosures of Cash Flow Information

The following table provides additional information concerning interest and income taxes paid as well as changes in noncash investing activities for the years ended December 31, 2019, 2018 and 2017:

(in millions)	For the years ended December 31,		
	2019	2018	2017
Cash paid during the year for interest, net of amounts capitalized	\$ 58	\$ 135	\$ 130
Cash paid (received) during the year for income taxes	(52)	6	(5)
Increase (decrease) in noncash property additions	41	(42)	25

Stock-Based Compensation

The Company accounts for stock-based compensation transactions using a fair value method and recognizes an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalizes the cost into natural gas and oil properties included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties. See Note 14 for a discussion of the Company's stock-based compensation.

Liability-Classified Awards

The Company classifies certain awards that can or will be settled in cash as liability awards. The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense or capitalized expense over the vesting period of the award. The Company's liability-classified performance unit awards that were granted in 2018 include a performance condition based on cash flow per debt-adjusted share and two market conditions, one based on absolute total shareholder return and the other on relative total shareholder return as compared to a group of the Company's peers. The Company's liability-classified performance unit awards that were granted in 2019 include a performance condition based on the return of average capital employed and the same two market conditions as in the 2018 awards. The fair values of the two market conditions are calculated by Monte Carlo models on a quarterly basis. See Note 14 for a discussion of the Company's stock-based compensation.

Treasury Stock

In the third quarter of 2018, the Company announced its intention to repurchase up to \$200 million of its outstanding common stock using a portion of the net proceeds from the Fayetteville Shale sale. At December 31, 2018, approximately \$180 million had been spent to repurchase 39,061,268 shares at an average price of \$4.63 per share. In the first quarter of 2019, the Company completed its share repurchase program by purchasing 5,260,687 shares of its outstanding common stock for approximately \$21 million at an average price of \$3.84 per share.

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan for certain key employees whereby participants may elect to defer and contribute a portion of their compensation to a Rabbi Trust, as permitted by the plan. The Company includes the assets and liabilities of its supplemental retirement savings plan in its consolidated balance sheet. Shares of the Company's common stock purchased under the non-qualified deferred compensation arrangement are held in the Rabbi Trust, are presented as treasury stock and are carried at cost. As of December 31, 2019 and 2018, 5,115 shares and 10,653 shares, respectively, were held in the Rabbi Trust and were accounted for as treasury stock. In 2018, 20,616 shares were released from the Rabbi Trust due to a reduction in our workforce. These shares are still held as treasury stock.

Foreign Currency Translation

The Company has designated the Canadian dollar as the functional currency for its activities in Canada. The cumulative translation effects of translating the accounts from the functional currency into the U.S. dollar at current exchange rates are included as a separate component of other comprehensive income within stockholders' equity.

New Accounting Standards Implemented in this Report

In February 2016, the FASB issued Accounting Standards Update No. 2016-2, Leases (Topic 842) ("Update 2016-2"), which seeks to increase transparency and comparability among organizations by, among other things, recognizing lease assets and lease liabilities on the balance sheet for leases classified as operating leases under previous GAAP and disclosing key information about leasing arrangements. The codification was amended through additional ASUs. For public entities, Update 2016-02 became effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company adopted Accounting Standards Codification ("ASC") 842 with an effective date of January 1, 2019 using the modified retrospective approach for all leases that existed at the date of initial application. The Company elected to apply the transition as of the beginning of the period of adoption. For leases that existed at the period of adoption on January 1, 2019, the incremental borrowing rate as of the adoption date was used to calculate the present value of remaining lease payments. Upon adoption of ASC 842, the Company recognized a discounted right-of-use asset and corresponding lease liability with opening balances of approximately \$105 million as of January 1, 2019. The adoption of the standard did not materially change the Company's consolidated statement of operations or its consolidated statement of cash flows. Please refer to Note 4 for additional disclosure.

New Accounting Standards Not Yet Adopted in this Report

In June 2016, the FASB issued Accounting Standards Update No. 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments ("Update 2016-13"). Update 2016-13 replaces the incurred loss model with an expected loss model, which is referred to as the current expected credit loss ("CECL") model. The CECL model is applicable to the measurement of credit losses on financial assets measured at amortized cost, including but not limited to trade receivables. For public business entities, the new standard is effective for annual reporting periods beginning after December 15, 2019, including interim periods within that reporting period.

From an evaluation of the Company's existing credit portfolio, which includes trade receivables from commodity sales, joint interest billings due from partners, other receivables and cash equivalents, historical credit losses have been de minimis and are expected to remain so in the future assuming no substantial changes to the business or creditworthiness of our business partners. As anticipated, the CECL model did not have a significant impact on Southwestern's consolidated financial statements or related control environment upon adoption on January 1, 2020.

(2) RESTRUCTURING CHARGES

As part of an ongoing strategic effort to reposition its portfolio, optimize operational performance and improve margins, the Company has incurred charges related to restructuring that include reductions in workforce, office consolidation and other costs, including those associated with the sale of a large asset such as the Fayetteville Shale. These charges are further discussed below. The following table presents a summary of the restructuring charges included in Operating Income for the years ended December 31, 2019, 2018 and 2017:

<i>(in millions)</i>	For the years ended December 31,		
	2019	2018 ⁽¹⁾	2017
Reduction in workforce (not Fayetteville Shale sale-related)	\$ —	\$ 23	\$ —
Fayetteville Shale sale-related	11	16	—
Total restructuring charges	\$ 11	\$ 39	\$ —

(1) Does not include a \$4 million gain for the year ended December 31, 2018 related to curtailment of the other postretirement benefit plan presented in other income (loss), net on the consolidated statements of operations.

The following table presents a summary of liabilities associated with the Company's restructuring activities at December 31, 2019, which are reflected in accounts payable on the consolidated balance sheet:

<i>(in millions)</i>	
Liability at December 31, 2018	\$ 5
Additions	11
Distributions	(14)
Liability at December 31, 2019	\$ 2

Reduction in Workforce (Not Fayetteville Shale Sale-Related)

In June 2018, the Company notified affected employees of a workforce reduction plan, which resulted primarily from a previously announced study of structural, process and organizational changes to enhance shareholder value and continues with respect to other aspects of the Company's business activities. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited.

The following table presents a summary of the restructuring charges related to workforce reduction plans included in Operating Income (Loss) for the year ended December 31, 2018:

	For the year ended December 31, 2018
<i>(in millions)</i>	
Severance (including payroll taxes)	\$ 21
Stock-based compensation	—
Other benefits	—
Outplacement services, other	2
Total reduction in workforce-related restructuring charges ⁽¹⁾	<u>\$ 23</u>

(1) Total restructuring charges for the Company's E&P and Marketing segments were \$21 million and \$2 million, respectively, for the year ended December 31, 2018.

Fayetteville Shale Sale-Related

In December 2018, the Company closed on the sale of the equity in certain of its subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, most employees associated with those assets became employees of the buyer although the employment of some was terminated. All affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. As of December 31, 2019, the Company has substantially completed the Fayetteville Shale sale-related employment terminations.

As a result of the Fayetteville Shale sale, the Company relocated certain employees and infrastructure to other locations and began the process of consolidating and reorganizing its office space. These charges related to office consolidation and reorganization have been recognized as restructuring charges.

In July 2019, the Company terminated its existing lease agreement in its headquarters office building and entered into a new 10-year lease agreement for a smaller portion of the building. Approximately \$3 million of the fees associated with the Company's headquarters office consolidation are reflected as restructuring charges for the year ended December 31, 2019. The Company also recognized additional severance costs in the third and fourth quarters of 2019, related to continued organizational restructuring, for which a liability of \$2 million has been accrued as of December 31, 2019. The following table presents a summary of the restructuring charges related to the consolidation and reorganization associated with the Fayetteville Shale sale included in Operating Income on the condensed statements of operations for the years ended December 31, 2019 and 2018:

	For the years ended December 31,	
	2019	2018
<i>(in millions)</i>		
Severance (including payroll taxes)	\$ 5	\$ 12
Office consolidation	6	4
Total Fayetteville Shale sale-related charges ⁽¹⁾⁽²⁾	<u>\$ 11</u>	<u>\$ 16</u>

(1) Total restructuring charges were \$11 million and \$16 million for the Company's E&P segment for the years ended December 31, 2019 and 2018, respectively.

(2) Does not include a \$4 million gain for the year ended December 31, 2018 related to the curtailment of the other postretirement benefit plan presented in Other Income (Loss), net on the consolidated statements of operations.

(3) DIVESTITURES

In August 2018, the Company entered into an agreement with Flywheel Energy Operating, LLC to sell 100% of the equity in the Company's subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets for \$1,865 million in cash, subject to customary closing adjustments, with an economic effective date of July 1, 2018.

In December 2018, the Company closed the Fayetteville Shale sale and received approximately \$1,650 million, which included purchase price adjustments of approximately \$215 million primarily related to the net cash flows from the economic

effective date to the closing date. The Company allocated the sale proceeds to gain on sale for the non-full cost pool assets and to capitalized costs for the full cost pool assets based on the proportion of the estimated fair values of the underlying assets. The fair values of these assets was estimated primarily using an income approach. Consequently, the Company recognized a gain on the sale of non-full cost pool assets of \$17 million and a reduction of \$887 million to its full cost pool assets. As the sale did not involve a significant change in proved reserves or significantly alter the relationship between capitalized costs and proved reserves, the Company recognized no gain or loss related to the full cost pool assets sold.

As part of the Fayetteville Shale sale agreement, the Company entered into certain natural gas derivative positions that were subsequently novated to the buyer in conjunction with finalization of the sale. The unrealized fair value of these derivatives at the closing of the sale in December 2018 was a net liability of \$151 million, which was transferred to the buyer. The unrealized loss associated with the novated positions was offset by the gain that the Company recognized when the liability was transferred to the buyer. These offsetting amounts were recognized on the consolidated statements of operations in (gain) loss on sale of operating assets, net. In addition, the Company paid \$22 million in premiums for these novated derivatives which was recorded as a loss in (gain) loss on sale of operating assets, net in 2018.

The Company retained certain contractual commitments related to firm transportation, with the buyer obligated to pay the transportation provider directly for these charges. As of December 31, 2019, approximately \$108 million of these contractual commitments remain, of which the Company will reimburse the buyer for certain of these potential obligations up to approximately \$58 million through 2020 depending on the buyer's actual use. At December 31, 2019, the Company has recorded a \$46 million liability for the estimated future payments.

In accordance with accounting guidance for Property, Plant and Equipment, assets held for sale are measured at the lower of the carrying value or fair value less costs to sell. Because the assets outside the full cost pool included in the Fayetteville Shale sale met the criteria for held for sale accounting as of September 30, 2018, the Company determined the carrying value of certain non-full cost pool assets exceeded the fair value less costs to sell. As a result, a non-cash impairment charge of \$161 million was recorded in the third quarter of 2018, of which \$145 million related to midstream gathering assets held for sale and \$15 million related to E&P assets held for sale. Additionally, the Company recorded a \$1 million non-cash impairment related to other non-core assets that were not included in the sale.

From the proceeds received, \$914 million was used to repurchase \$900 million of the Company's outstanding senior notes, including premiums and \$9 million in accrued interest paid in December 2018. In addition, \$201 million, including approximately \$1 million in commissions, was used to repurchase approximately 44 million shares of the Company's outstanding common stock, including \$21 million in the first quarter of 2019. The Company earmarked the remaining net proceeds from the sale to supplement 2019 and 2020 Appalachia development and for general corporate purposes. Pending these other uses, a portion of these remaining net proceeds has been used to repay revolving credit facility borrowings until investments are made.

During 2019, the Company sold non-core acreage for \$38 million. There was no production or proved reserves associated with this acreage. In addition, during July 2019, the Company sold the land associated with its headquarters office building for \$16 million and recognized a \$2 million gain on the sale. The Company also from time to time sells leases and other properties whose value, individually, is not material but is reflected in the Company's financial statements.

(4) LEASES

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) ("Update 2016-02"), which seeks to increase transparency and comparability among organizations by, among other things, recognizing lease assets and lease liabilities on the balance sheet for leases classified as operating leases under previous GAAP and disclosing key information about leasing arrangements. The codification was amended through additional ASUs. For public entities, Update 2016-02 became effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company adopted ASC 842 with an effective date of January 1, 2019 using the modified retrospective approach for all leases that existed at the date of initial adoption. The Company elected to apply the transition as of the beginning of the period of adoption. For leases that existed at the period of adoption on January 1, 2019, the incremental borrowing rate as of the adoption date was used to calculate the present value of remaining lease payments.

The standard provides optional practical expedients to ease the burden of transition. The Company has adopted the following practical expedients through implementation:

- an election not to apply the recognition requirements in the leases standard to short-term leases and recognize lease payments in the consolidated statement of operations (a lease that at commencement date has an initial term of 12 months or less and does not contain a purchase option that the Company is reasonably certain to exercise);

- a package of practical expedients to not reassess: whether a contract is or contains a lease, lease classification and initial direct costs;
- a practical expedient that permits combining lease and non-lease components in a contract and accounting for the combination as a lease (elected by asset class);
- a practical expedient to not reassess certain land easements in existence prior to January 1, 2019; and
- an election to adopt the modified retrospective approach for all leases existing at or entered into after the initial date of adoption which does not require a restatement of prior period. No cumulative-effect adjustment to retained earnings was required as a result of the modified retrospective approach.

Upon adoption of ASC 842, the Company recognized a discounted right-of-use asset and corresponding lease liability with opening balances of approximately \$105 million as of January 1, 2019. The adoption of the standard did not materially change the Company's consolidated statement of operations or its consolidated statement of cash flows.

The Company determines if a contract contains a lease at inception. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration. A right-of-use asset and corresponding lease liability are recognized on the balance sheet at commencement at an amount based on the present value of the remaining lease payments over the lease term. As the implicit rate of the lease is not always readily determinable, the Company uses the incremental borrowing rate to calculate the present value of the lease payments based on information available at commencement date, such as the initial lease term. Operating right-of-use assets and operating lease liabilities are presented separately on the consolidated balance sheet. The Company does not have any finance leases as of December 31, 2019. By policy election, leases with an initial term of twelve months or less are not recorded on the balance sheet. The Company recognizes lease expense for these leases on a straight-line basis, and variable lease payments are recognized in the period as incurred.

Certain leases contain both lease and non-lease components. The Company has chosen to account for most of these leases as a single lease component instead of bifurcating lease and non-lease components. However, for compression service leases and fleet vehicle leases, the lease and non-lease components are accounted for separately.

The Company leases drilling rigs, pressure pumping equipment, vehicles, office space, certain water transportation lines, an aircraft and other equipment under non-cancelable operating leases expiring through 2032. Certain lease agreements include options to renew the lease, early terminate the lease or purchase the underlying asset(s). The Company determines the lease term at the lease commencement date as the non-cancelable period of the lease, including options to extend or terminate the lease when such an option is reasonably certain to be exercised. The Company's water transportation lines are the only leases with renewal options that are reasonably certain to be exercised. These renewal options are reflected in the right-of-use asset and lease liability balances.

In July 2019, the Company terminated its existing lease agreement and entered into a new ten-year lease agreement for a smaller portion of the headquarters office building, which resulted in the Company making a \$6 million residual value guarantee short-fall payment to the building's previous lessor. The Company's variable lease costs are primarily comprised of variable operating charges incurred in connection with the new building lease which are expected to continue throughout the lease term. There are currently no material residual value guarantees in the Company's existing leases.

The components of lease costs are shown below:

<i>(in millions)</i>	For the year ended December 31, 2019
Operating lease cost	\$ 45
Short-term lease cost	45
Variable lease cost	1
Total lease cost	<u>\$ 91</u>

As of December 31, 2019, the Company has operating leases of \$15 million, related primarily to compressor and information technology leases, that have been executed but not yet commenced. These operating leases are planned to commence during 2020 with lease terms expiring through 2030. The Company's existing operating leases do not contain any material restrictive covenants.

[Table of Contents](#)
[Index to Financial Statements](#)

Supplemental cash flow information related to leases is set forth below:

<i>(in millions)</i>	<u>For the year ended December 31, 2019</u>
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	\$ 47
Right-of-use assets obtained in exchange for operating liabilities:	
Operating leases	\$ 95

Supplemental balance sheet information related to leases is as follows:

<i>(in millions)</i>	<u>December 31, 2019</u>
Right-of-use asset balance:	
Operating leases	\$ 159
Lease liability balance:	
Current operating leases	\$ 34
Long-term operating leases	119
Total operating leases	<u>\$ 153</u>
Weighted average remaining lease term: <i>(years)</i>	
Operating leases	6.6
Weighted average discount rate:	
Operating leases	5.33 %

Maturity analysis of operating lease liabilities:

<i>(in millions)</i>	<u>December 31, 2019</u>
2020	\$ 41
2021	33
2022	22
2023	19
2024	15
Thereafter	52
Total undiscounted lease liability	182
Imputed interest	(29)
Total discounted lease liability	<u>\$ 153</u>

Undiscounted maturities of operating leases accounted for under ASC 840:

<i>(in millions)</i>	<u>December 31, 2018</u>
2019	\$ 38
2020	28
2021	14
2022	6
2023	5
Thereafter	4
Total minimum payments required	<u>\$ 95</u>

(5) REVENUE RECOGNITION

Effective January 1, 2018, the Company adopted ASC 606, “Revenue from Contracts with Customers,” using the modified retrospective method applied to those contracts which were not completed as of January 1, 2018. Under the modified retrospective method, the Company recognizes the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings; however, no material adjustment was required as a result of adopting ASC 606. Results for reporting periods beginning on January 1, 2018 are presented under the new revenue standard. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those

periods. The Company performed an analysis of the impact of adopting ASC 606 across all revenue streams and did not identify any changes to its revenue recognition policies that resulted in a material impact to its consolidated financial statements.

Revenues from Contracts with Customers

Natural gas and liquids. Natural gas, oil and NGL sales are recognized when control of the product is transferred to the customer at a designated delivery point. The pricing provisions of the Company's contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, quality of the product and prevailing supply and demand conditions in the geographic areas in which the Company operates. Under the Company's sales contracts, the delivery of each unit of natural gas, oil and NGLs represents a separate performance obligation, and revenue is recognized at the point in time when the performance obligations are fulfilled. There is no significant financing component to the Company's revenues as payment terms are typically within 30 to 60 days of control transfer. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations.

The Company records revenue from its natural gas and liquids production in the amount of its net revenue interest in sales from its properties. Accordingly, natural gas and liquid sales are not recognized for deliveries in excess of the Company's net revenue interest, while natural gas and liquid sales are recognized for any under-delivered volumes. Production imbalances are generally recorded as receivables and payables and not contract assets or contract liabilities as the imbalances are between the Company and other working interest owners, not the end customer.

Marketing. The Company, through its marketing affiliate, generally markets natural gas, oil and NGLs for its affiliated E&P companies as well as other joint owners who choose to market with the Company. In addition, the Company markets some products purchased from third parties. Marketing revenues for natural gas, oil and NGL sales are recognized when control of the product is transferred to the customer at a designated delivery point. The pricing provisions of the Company's contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, quality of the product and prevailing supply and demand conditions. Under the Company's marketing contracts, the delivery of each unit of natural gas, oil and NGLs represents a separate performance obligation, and revenue is recognized at the point in time when the performance obligations are fulfilled. Customers are invoiced and revenues are recorded each month as natural gas, oil and NGLs are delivered, and payment terms are typically within 30 to 60 days of control transfer. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations.

Gas gathering. Prior to the Fayetteville Shale sale in December 2018, the Company, through its midstream gathering affiliate, gathered natural gas pursuant to a variety of contracts with customers, including an affiliated E&P company. The performance obligations for gas gathering services included delivery of each unit of natural gas to the designated delivery point, which may include treating of certain natural gas units to meet interstate pipeline specifications. Revenue was recognized at the point in time when performance obligations were fulfilled. Under the Company's gathering contracts, customers were invoiced and revenue was recognized each month based on the volume of natural gas transported and treated at a contractually agreed upon price per unit. Payment terms were typically within 30 to 60 days of completion of the performance obligations. Furthermore, consideration from a customer corresponded directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognized revenue in the amount to which the Company had a right to invoice and had not disclosed information regarding its remaining performance obligations. Any imbalances were settled on a monthly basis by cashing-out with the respective shipper. Accordingly, there were no contract assets or contract liabilities related to the Company's gas gathering revenues.

Disaggregation of Revenues

The Company presents a disaggregation of E&P revenues by product in the consolidated statements of operations net of intersegment revenues. The following table reconciles operating revenues as presented on the consolidated statements of operations to the operating revenues by segment:

<i>(in millions)</i>	E&P	Marketing	Intersegment Revenues	Total
<u>Year ended December 31, 2019</u>				
Gas sales	\$ 1,207	\$ —	\$ 34	\$ 1,241
Oil sales	220	—	3	223
NGL sales	274	—	—	274
Marketing	—	2,849	(1,552)	1,297
Other ⁽¹⁾	2	1	—	3
Total	\$ 1,703	\$ 2,850	\$ (1,515)	\$ 3,038
<u>Year ended December 31, 2018</u>				
Gas sales	\$ 1,974	\$ —	\$ 24	\$ 1,998
Oil sales	193	—	3	196
NGL sales	353	—	(1)	352
Marketing	—	3,497	(2,275)	1,222
Gas gathering ⁽²⁾	—	248	(159)	89
Other ⁽¹⁾	5	—	—	5
Total	\$ 2,525	\$ 3,745	\$ (2,408)	\$ 3,862
<u>Year ended December 31, 2017</u>				
Gas sales	\$ 1,775	\$ —	\$ 18	\$ 1,793
Oil sales	101	—	1	102
NGL sales	206	—	—	206
Marketing	—	2,867	(1,895)	972
Gas gathering ⁽²⁾	—	331	(205)	126
Other ⁽¹⁾	4	—	—	4
Total	\$ 2,086	\$ 3,198	\$ (2,081)	\$ 3,203

(1) Other E&P revenues consists primarily of water sales to third-party operators and other marketing revenues consists primarily of sales of gas from storage.

(2) The Company's gas gathering assets were divested in December 2018 as part of the Fayetteville Shale sale.

Associated E&P revenues are also disaggregated for analysis on a geographic basis by the core areas in which the Company operates, which are primarily in Pennsylvania and West Virginia. In December 2018, the Company sold 100% of its Fayetteville Shale assets.

<i>(in millions)</i>	For the years ended December 31,		
	2019	2018	2017
Northeast Appalachia	\$ 964	\$ 1,165	\$ 837
Southwest Appalachia	736	817	498
Fayetteville Shale	—	537	743
Other	3	6	8
Total	\$ 1,703	\$ 2,525	\$ 2,086

Receivables from Contracts with Customers

The following table reconciles the Company's receivables from contracts with customers to consolidated accounts receivable as presented on the consolidated balance sheet:

<i>(in millions)</i>	December 31, 2019	December 31, 2018
Receivables from contracts with customers	\$ 284	\$ 494
Other accounts receivable	61	87
Total accounts receivable	\$ 345	\$ 581

Amounts recognized against the Company's allowance for doubtful accounts related to receivables arising from contracts with customers were immaterial for the years ended December 31, 2019 and 2018. The Company has no contract assets or contract liabilities associated with its revenues from contracts with customers.

(6) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas, oil and NGLs, which impacts the predictability of its cash flows related to the sale of those commodities. These risks are managed by the Company's use of certain derivative financial instruments. As of December 31, 2019, the Company's derivative financial instruments consisted of fixed price swaps, two-way costless collars, three-way costless collars, basis swaps, call options and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	If the Company sells a fixed price swap, the Company receives a fixed price for the contract and pays a floating market to the counterparty. If the Company purchases a fixed price swap, the Company receives a floating market price for the contract and pays a fixed price to the counterparty.
Two-way costless collars	Arrangements that contain a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, the Company pays the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party, and (3) if the index price is below the floor price, the Company will receive the difference between the floor price and the index price.
Three-way costless collars	Arrangements that contain a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the sold call strike price, the Company pays the counterparty the difference between the index price and sold call strike price, (2) if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party, (3) if the index price is between the sold put strike price and the purchased put strike price, the Company will receive the difference between the purchased put strike price and the index price, and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price.
Basis swaps	Arrangements that guarantee a price differential for natural gas from a specified delivery point. If the Company sells a basis swap, the Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. If the Company purchases a basis swap, the Company pays the counterparty if the price differential is greater than the state terms of the contract and receives a payment from the counterparty if the price differential is less than the stated terms of the contract.
Call options	The Company purchases and sells call options in exchange for a premium. If the Company purchases a call option, the Company receives from the counterparty the excess (if any) of the market price over the strike price of the call option at the time of settlement, but if the market price is below the call's strike price, no payment is due from either party. If the Company sells a call option, the Company pays the counterparty the excess (if any) of the market price over the strike price at the time of settlement, but if the market price is below the call's strike price, no payment is due from either party.
Interest rate swaps	Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes.

The Company chooses counterparties for its derivative instruments that it believes are creditworthy at the time the transactions are entered into, and the Company actively monitors the credit ratings and credit default swap rates of these counterparties where applicable. However, there can be no assurance that a counterparty will be able to meet its obligations to the Company. The Company presents its derivative positions on a gross basis and does not net the asset and liability positions.

As part of the Fayetteville Shale sale agreement, the Company entered into certain natural gas derivative positions that were subsequently novated to the buyer in conjunction with finalization of the sale. The derivatives that were novated to the buyer are not included in the tables below.

The following tables provide information about the Company's financial instruments that are sensitive to changes in commodity prices and that are used to protect the Company's exposure. None of the financial instruments below are designated

for hedge accounting treatment. The tables present the notional amount, the weighted average contract prices and the fair value by expected maturity dates as of December 31, 2019:

Financial Protection on Production

	Volume (Bcf)	Weighted Average Price per MMBtu					Basis Differential	Fair value at December 31, 2019 (\$ in millions)
		Swaps	Sold Puts	Purchased Puts	Sold Calls			
Natural Gas								
<u>2020</u>								
Fixed price swaps	280	\$ 2.51	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 76 ⁽¹⁾
Two-way costless collars	31	—	—	2.56	2.85	—	—	6
Three-way costless collars	185	—	2.28	2.65	3.00	—	—	42
Total	496							\$ 124
<u>2021</u>								
Fixed price swaps	30	\$ 2.54	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 7
Two-way costless collars	17	—	—	2.50	2.83	—	—	—
Three-way costless collars	213	—	2.23	2.53	2.90	—	—	—
Total	260							\$ 7
<u>2022</u>								
Three-way costless collars	31	\$ —	\$ 2.30	\$ 2.69	\$ 3.15	\$ —	\$ —	\$ 2
Basis swaps								
2020	198	\$ —	\$ —	\$ —	\$ —	\$ (0.31)	\$ —	\$ —
2021	86	—	—	—	—	0.04	—	7
2022	45	—	—	—	—	(0.50)	—	(1)
Total	329							\$ 6

(1) Includes \$9 million in premiums paid related to certain natural gas fixed price swaps recognized as a component of derivative assets within current assets on the consolidated balance sheet at December 31, 2019. As certain natural gas fixed price swaps settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the consolidated statement of operations.

	Volume (MBbls)	Weighted Average Price per Bbl				Fair value at December 31, 2019 (\$ in millions)
		Swaps	Sold Puts	Purchased Puts	Sold Calls	
Oil						
<u>2020</u>						
Fixed price swaps	3,465	\$ 57.83	\$ —	\$ —	\$ —	\$ (2)
Two-way costless collars	966	—	—	56.89	59.81	—
Three-way costless collars	971	—	45.12	55.12	59.68	(1)
Total	5,402					\$ (3)
<u>2021</u>						
Fixed price swaps	1,584	\$ 53.20	\$ —	\$ —	\$ —	\$ (1)
Three-way costless collars	1,445	—	43.52	53.25	58.14	(1)
Total	3,029					\$ (2)
<u>2022</u>						
Fixed price swaps	438	\$ 51.74	\$ —	\$ —	\$ —	\$ —
Propane						
<u>2020</u>						
Fixed price swaps	4,746	\$ 23.90	\$ —	\$ —	\$ —	\$ 21
Two-way costless collars	366	—	—	25.20	29.40	2
Total	5,112					\$ 23
<u>2021</u>						
Fixed price swaps	2,460	\$ 21.77	\$ —	\$ —	\$ —	\$ 3
Ethane						
<u>2020</u>						
Fixed price swaps	7,520	\$ 8.84	\$ —	\$ —	\$ —	\$ 11
<u>2021</u>						
Fixed price swaps	2,410	\$ 7.53	\$ —	\$ —	\$ —	\$ —

Other Derivative Contracts

	Volume (Bcf)	Weighted Average Strike Price per MMBtu	Fair value at December 31, 2019 (\$ in millions)
Purchased Call Options – Natural Gas			
2020	104	\$ 3.46	\$ 1
2021	57	3.52	2
Total	161		\$ 3
Sold Call Options – Natural Gas			
2020	173	\$ 3.24	\$ (3)
2021	115	3.33	(6)
2022	58	3.00	(5)
2023	6	3.00	(1)
2024	9	3.00	(3)
Total	361		\$ (18)
Sold Call Options – Oil			
2021	—	\$ 60.00	\$ (1)

Natural Gas Storage ⁽¹⁾	Volume (Bcf)	Weighted Average Strike Price per MMBtu		Fair value at December 31, 2019 (\$ in millions)
		Swaps	Basis Differential	
<u>2020</u>				
Purchased fixed price swap	—	\$ 2.37	\$ —	\$ —
Purchased basis swap	—	—	(0.32)	—
Sold fixed price swap	1	3.06	—	1
Sold basis swap	—	—	(0.32)	—
Total	1			\$ 1

(1) The Company has entered into certain derivatives to protect the value of volumes of natural gas injected into a storage facility that will be withdrawn at a later date.

Purchased Fixed Price Swaps – Marketing (Natural Gas) ⁽¹⁾	Volume (Bcf)	Weighted Average Strike Price per MMBtu	Fair value at December 31, 2019 (\$ in millions)
2020	7	\$ 2.44	\$ (1)
2021	6	2.44	—
Total	13		\$ (1)

(1) The Company has entered into a limited number of derivatives to protect the value of certain long-term sales contracts.

At December 31, 2019, the net fair value of the Company's financial instruments related to commodities was a \$155 million asset.

As of December 31, 2019, the Company had no positions designated for hedge accounting treatment. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statement of operations reflects the gains and losses on both settled and unsettled derivatives. The Company calculates gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period. Only the settled gains and losses are included in the Company's realized commodity price calculations.

The Company is a party to interest rate swaps that were entered into to mitigate the Company's exposure to volatility in interest rates. The interest rate swaps have a notional amount of \$170 million and expire in June 2020. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives on the consolidated statements of operations.

The balance sheet classification of the assets and liabilities related to derivative financial instruments are summarized below as of December 31, 2019 and 2018:

Derivative Assets

<i>(in millions)</i>	Balance Sheet Classification	Fair Value	
		December 31, 2019	December 31, 2018
Derivatives not designated as hedging instruments:			
Fixed price swap – natural gas	Derivative assets	\$ 77 ⁽¹⁾	\$ 32
Fixed price swap – oil	Derivative assets	4	13
Fixed price swap – propane	Derivative assets	21	11
Fixed price swap – ethane	Derivative assets	11	7
Two-way costless collar – natural gas	Derivative assets	10	11
Two-way costless collar – oil	Derivative assets	5	6
Two-way costless collar – propane	Derivative assets	2	—
Three-way costless collar – natural gas	Derivative assets	126	41
Three-way costless collar – oil	Derivative assets	3	—
Basis swap – natural gas	Derivative assets	17	8
Purchased call option – natural gas	Derivative assets	1	—
Fixed price swap – natural gas storage	Derivative assets	1	—
Interest rate swap	Derivative assets	—	1
Fixed price swap – natural gas	Other long-term assets	7	6
Fixed price swap – oil	Other long-term assets	1	6
Fixed price swap – propane	Other long-term assets	3	—
Fixed price swap – ethane	Other long-term assets	—	1
Two-way costless collar – natural gas	Other long-term assets	4	—
Two-way costless collar – oil	Other long-term assets	—	5
Three-way costless collar – natural gas	Other long-term assets	74	34
Three-way costless collar – oil	Other long-term assets	7	—
Basis swap – natural gas	Other long-term assets	15	3
Purchased call options – natural gas	Other long-term assets	2	6
Total derivative assets		<u>\$ 391</u>	<u>\$ 191</u>

- (1) Includes \$9 million in premiums paid related to certain natural gas fixed price swaps recognized as a component of derivative assets within current assets on the consolidated balance sheet at December 31, 2019. As certain natural gas fixed price swaps settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the consolidated statements of operations.

Derivative Liabilities

<i>(in millions)</i>	Balance Sheet Classification	Fair Value	
		December 31, 2019	December 31, 2018
Derivatives not designated as hedging instruments:			
Purchased fixed price swap – natural gas	Derivative liabilities	\$ 1	\$ —
Purchased fixed price swap – oil	Derivative liabilities	—	6
Fixed price swap – natural gas	Derivative liabilities	1	9
Fixed price swap – oil	Derivative liabilities	6	—
Fixed price swap – ethane	Derivative liabilities	—	3
Two-way costless collar – natural gas	Derivative liabilities	4	7
Two-way costless collar – oil	Derivative liabilities	5	—
Three-way costless collar – natural gas	Derivative liabilities	84	33
Three-way costless collar – oil	Derivative liabilities	4	—
Basis swap – natural gas	Derivative liabilities	17	18
Sold call option – natural gas	Derivative liabilities	3	3
Fixed price swap – natural gas	Other long-term liabilities	—	1
Fixed price swap – oil	Other long-term liabilities	2	—
Two-way costless collar – natural gas	Other long-term liabilities	4	—
Two-way costless collar – oil	Other long-term liabilities	—	1
Three-way costless collar – natural gas	Other long-term liabilities	72	35
Three-way costless collar – oil	Other long-term liabilities	8	—
Basis swap – natural gas	Other long-term liabilities	9	4
Sold call option – natural gas	Other long-term liabilities	15	19
Sold call option – oil	Other long-term liabilities	1	—
Total derivative liabilities		<u>\$ 236</u>	<u>\$ 139</u>

The following tables summarize the before-tax effect of the Company's derivative instruments on the consolidated statements of operations for the years ended December 31, 2019 and 2018:

Unsettled Gain (Loss) on Derivatives Recognized in Earnings

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Unsettled	For the years ended December 31,	
		2019	2018
<i>(in millions)</i>			
Purchased fixed price swap – natural gas	Gain (Loss) on Derivatives	\$ (1)	\$ —
Purchased fixed price swap – oil	Gain (Loss) on Derivatives	6	(6)
Fixed price swap – natural gas	Gain (Loss) on Derivatives	46	(27)
Fixed price swap – oil	Gain (Loss) on Derivatives	(22)	19
Fixed price swap – propane	Gain (Loss) on Derivatives	13	11
Fixed price swap – ethane	Gain (Loss) on Derivatives	6	5
Two-way costless collar – natural gas	Gain (Loss) on Derivatives	2	—
Two-way costless collar – oil	Gain (Loss) on Derivatives	(10)	10
Two-way costless collar – propane	Gain (Loss) on Derivatives	2	—
Three-way costless collar – natural gas	Gain (Loss) on Derivatives	37	(48)
Three-way costless collar – oil	Gain (Loss) on Derivatives	(2)	—
Basis swap – natural gas	Gain (Loss) on Derivatives	17	10
Purchased call option – natural gas	Gain (Loss) on Derivatives	(3)	4
Sold call option – natural gas	Gain (Loss) on Derivatives	4	(4)
Sold call option – oil	Gain (Loss) on Derivatives	(1)	—
Fixed price swap – natural gas storage	Gain (Loss) on Derivatives	1	—
Interest rate swap	Gain (Loss) on Derivatives	(1)	2
Total gain (loss) on unsettled derivatives		\$ 94	\$ (24)

Settled Gain (Loss) on Derivatives Recognized in Earnings ⁽¹⁾

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled	For the years ended December 31,	
		2019	2018
<i>(in millions)</i>			
Purchased fixed price swap – oil	Gain (Loss) on Derivatives	\$ (3)	\$ —
Fixed price swap – natural gas	Gain (Loss) on Derivatives	78	(32)
Fixed price swap – oil	Gain (Loss) on Derivatives	10	—
Fixed price swap – propane	Gain (Loss) on Derivatives	29	(6)
Fixed price swap – ethane	Gain (Loss) on Derivatives	17	(8)
Two-way costless collar – natural gas	Gain (Loss) on Derivatives	16	(1)
Two-way costless collar – oil	Gain (Loss) on Derivatives	6	—
Two-way costless collar – propane	Gain (Loss) on Derivatives	2	—
Three-way costless collar – natural gas	Gain (Loss) on Derivatives	31	(9)
Basis swap – natural gas	Gain (Loss) on Derivatives	(3)	(31)
Purchased call option – natural gas	Gain (Loss) on Derivatives	(1) ⁽²⁾	2 ⁽²⁾
Sold call option – natural gas	Gain (Loss) on Derivatives	(1)	(7)
Sold call option – oil	Gain (Loss) on Derivatives	—	(2)
Purchased fixed price swap – natural gas storage	Gain (Loss) on Derivatives	(1)	—
Total gain (loss) on settled derivatives		\$ 180	\$ (94)
Total gain (loss) on derivatives		\$ 274	\$ (118)

(1) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.

(2) Includes \$1 million amortization of premiums paid related to certain natural gas purchased call options for each of the years ended December 31, 2019 and 2018, which is included in gain (loss) on derivatives on the consolidated statement of operations.

(7) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

In 2019, changes in AOCI primarily related to settlements in the Company's pension and other postretirement benefits. The following tables detail the components of accumulated other comprehensive income (loss) and the related tax effects, for the year ended December 31, 2019:

<i>(in millions)</i>	For the year ended December 31, 2019		
	Pension and Other Postretirement	Foreign Currency	Total
Beginning balance, December 31, 2018	\$ (22)	\$ (14)	\$ (36)
Other comprehensive loss before reclassifications	(5)	—	(5)
Amounts reclassified from other comprehensive income ⁽¹⁾	8	—	8
Net current-period other comprehensive income	3	—	3
Ending balance, December 31, 2019	\$ (19)	\$ (14)	\$ (33)

(1) See separate table below for details about these reclassifications.

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from/to Accumulated Other Comprehensive Income	
		For the year ended December 31, 2019 <i>(in millions)</i>	
Pension and other postretirement:			
Amortization of prior service cost and net loss ⁽¹⁾	Other Income, Net	\$	10
	Provision for income taxes		(2)
	Net income	\$	8
Total reclassifications for the period	Net income	\$	8

(1) See Note 13 for additional details regarding the Company's pension and other postretirement benefit plans.

(8) FAIR VALUE MEASUREMENTS

Assets and liabilities measured at fair value on a recurring basis

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2019 and 2018 were as follows:

<i>(in millions)</i>	December 31, 2019		December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	\$ 5	\$ 5	\$ 201	\$ 201
2018 revolving credit facility due April 2024 ⁽¹⁾	34	34	—	—
Senior notes ⁽²⁾	2,228	2,085	2,342	2,190
Derivative instruments, net	155 ⁽³⁾	155 ⁽³⁾	52	52

(1) In October 2019, the Company amended its 2018 revolving credit facility agreement which, among other things, extended the maturity from 2023 to 2024.

(2) Excludes unamortized debt issuance costs and debt discounts.

(3) Includes \$9 million in premiums paid related to certain natural gas fixed price swaps recognized as a component of derivative assets within current assets on the consolidated balance sheet.

The fair value hierarchy prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations – Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.

Level 2 valuations – Consist of quoted market information for the calculation of fair market value.

Level 3 valuations – Consist of internal estimates and have the lowest priority.

The carrying values of cash and cash equivalents, including marketable securities, accounts receivable, other current assets, accounts payable and other current liabilities on the consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company's senior notes were based on the market value of the Company's publicly traded debt as determined based on the market prices of the Company's senior notes. These instruments were previously classified as a Level 2 measurement but certain senior notes were updated to a Level 1 in the second quarter of 2018 as the market activity for a portion of the Company's debt resulted in timely quoted prices. In 2019, the 4.10% Senior Notes due March 2022 were reclassified as a Level 2 measurement due to relative market inactivity. The 4.05% Senior Notes due January 2020, which were classified as a Level 2 measurement at December 31, 2018, were retired in December 2019.

The carrying value of the borrowings under the Company's revolving credit facility (to the extent utilized) approximates fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its revolving credit facility to be a Level 1 measurement on the fair value hierarchy.

Derivative Instruments: The fair value of all derivative instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

The Company has classified its derivatives into the fair value hierarchy levels depending upon the data utilized to determine their fair values. The Company's fixed price swaps (Level 2) are estimated using third-party discounted cash flow calculations using the New York Mercantile Exchange ("NYMEX") futures index for natural gas and oil derivatives and Oil Price Information Service ("OPIS") for ethane and propane derivatives. The Company utilizes discounted cash flow models for valuing its interest rate derivatives (Level 2). The net derivative values attributable to the Company's interest rate derivative contracts as of December 31, 2019 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate ("LIBOR") yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's interest rate derivative contracts expire in June 2020.

The Company's call options, two-way costless collars and three-way costless collars (Level 2) are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX and OPIS futures index, interest rates, volatility and credit worthiness. The Company's basis swaps (Level 2) are estimated using third-party calculations based upon forward commodity price curves. These instruments were previously classified as a Level 3 measurement in the fair value hierarchy but were updated to a Level 2 measurement in the second quarter of 2018 as a result of the Company's ability to derive volatility inputs and forward commodity price curves from directly observable sources.

Inputs to the Black-Scholes model, including the volatility input are obtained from a third-party pricing source, with independent verification of the most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively.

Assets and liabilities measured at fair value on a recurring basis are summarized below:

December 31, 2019

(in millions)	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Assets				
Fixed price swap – natural gas ⁽¹⁾	\$ —	\$ 84	\$ —	\$ 84
Fixed price swap – oil	—	5	—	5
Fixed price swap – propane	—	24	—	24
Fixed price swap – ethane	—	11	—	11
Two-way costless collar – natural gas	—	14	—	14
Two-way costless collar – oil	—	5	—	5
Two-way costless collar – propane	—	2	—	2
Three-way costless collar – natural gas	—	200	—	200
Three-way costless collar – oil	—	10	—	10
Basis swap – natural gas	—	32	—	32
Purchased call option – natural gas	—	3	—	3
Fixed price swap – natural gas storage	—	1	—	1
Liabilities				
Purchased fixed price swap – natural gas	—	(1)	—	(1)
Fixed price swap – natural gas	—	(1)	—	(1)
Fixed price swap – oil	—	(8)	—	(8)
Two-way costless collar – natural gas	—	(8)	—	(8)
Two-way costless collar – oil	—	(5)	—	(5)
Three-way costless collar – natural gas	—	(156)	—	(156)
Three-way costless collar – oil	—	(12)	—	(12)
Basis swap – natural gas	—	(26)	—	(26)
Sold call option – natural gas	—	(18)	—	(18)
Sold call option – oil	—	(1)	—	(1)
Total	\$ —	\$ 155	\$ —	\$ 155

- (1) Includes \$9 million in premiums paid related to certain natural gas fixed price swaps recognized as a component of derivative assets within current assets on the consolidated balance sheet at December 31, 2019. As certain natural gas fixed price swaps settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the consolidated statement of operations.

December 31, 2018

<i>(in millions)</i>	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Assets				
Fixed price swap – natural gas	\$ —	\$ 38	\$ —	\$ 38
Fixed price swap – oil	—	19	—	19
Fixed price swap – propane	—	11	—	11
Fixed price swap – ethane	—	8	—	8
Two-way costless collar – natural gas	—	11	—	11
Two-way costless collar – oil	—	11	—	11
Three-way costless collar – natural gas	—	75	—	75
Basis swaps – natural gas	—	11	—	11
Purchased call option – natural gas	—	6	—	6
Interest rate swap	—	1	—	1
Liabilities				
Purchased fixed price swap – oil	—	(6)	—	(6)
Fixed price swap – natural gas	—	(10)	—	(10)
Fixed price swap – ethane	—	(3)	—	(3)
Two-way costless collar – natural gas	—	(7)	—	(7)
Two-way costless collar – oil	—	(1)	—	(1)
Three-way costless collar – natural gas	—	(68)	—	(68)
Basis swap – natural gas	—	(22)	—	(22)
Sold call option – natural gas	—	(22)	—	(22)
Total	\$ —	\$ 52	\$ —	\$ 52

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2019 and 2018. The fair values of Level 3 derivative instruments were estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consisted of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflected reasonable assumptions a marketplace participant would have used as of December 31, 2019 and 2018. Commodity derivatives previously presented as Level 3 were transferred to Level 2 in the second quarter of 2018 as the Company moved from using proprietary volatility inputs and forward curves to more widely available published information, increasing market observability.

<i>(in millions)</i>	For the years ended December 31,	
	2019	2018
Balance at beginning of year	\$ —	\$ 22
Total gains (losses):		
Included in earnings	—	(17)
Settlements ⁽¹⁾	—	1
Transfers into/out of Level 3 ⁽²⁾	—	(6)
Balance at end of period	\$ —	\$ —
Change in gains (losses) included in earnings relating to derivatives still held as of December 31	\$ —	\$ —

(1) Includes \$1 million for amortization of premiums paid related to certain natural gas purchased call options for the year ended December 31, 2018.

(2) Commodity derivatives previously presented as Level 3 were transferred to Level 2 in the second quarter of 2018 as the Company moved from using proprietary volatility inputs and forward curves to more widely available published information, increasing market observability.

See Note 13 for a discussion of the fair value measurement of the Company's pension plan assets.

Assets and liabilities measured at fair value on a nonrecurring basis

In accordance with accounting guidance for Property, Plant and Equipment, assets held for sale are measured at the lower of carrying value or fair value less costs to sell. Because the assets outside of the full cost pool included in the Fayetteville Shale sale met the criteria for held for sale accounting in the third quarter of 2018, the Company determined the carrying value of certain non-full cost pool assets exceeded the fair value less costs to sell. As a result, the Company recorded a non-cash

impairment charge of \$161 million for the year ended December 31, 2018, of which \$145 million related to midstream gathering assets and \$15 million related to E&P which were both reflected as assets held for sale in the third quarter of 2018. Additionally, the Company recorded a \$1 million non-cash impairment related to other non-core assets that were not included in the sale. The estimated fair value of the gathering assets was based on an estimated discounted cash flow model and market assumptions. The significant Level 3 assumptions used in the calculation of estimated discounted cash flows included future commodity prices, projections of estimated quantities of natural gas reserves, operating costs, projections of future rates of production, inflation factors and risk adjusted discount rates. In 2019, the Company determined that the \$26 million carrying value of certain non-core assets exceeded their respective fair value less costs to sell and recognized a \$16 million non-cash impairment. The Company used Level 3 measurements to determine the fair value of these assets.

(9) DEBT

The components of debt as of December 31, 2019 and 2018 consisted of the following:

<i>(in millions)</i>	December 31, 2019			Total
	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	
Long-term debt:				
Variable rate (4.310% at December 31, 2019) 2018 revolving credit facility, due April 2024	\$ 34	\$ — ⁽¹⁾	\$ —	\$ 34
4.10% Senior Notes due March 2022	213	(1)	—	212
4.95% Senior Notes due January 2025 ⁽²⁾	892	(5)	(1)	886
7.50% Senior Notes due April 2026	639	(7)	—	632
7.75% Senior Notes due October 2027	484	(6)	—	478
Total long-term debt	<u>\$ 2,262</u>	<u>\$ (19)</u>	<u>\$ (1)</u>	<u>\$ 2,242</u>

<i>(in millions)</i>	December 31, 2018			Total
	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	
Long-term debt:				
Variable rate (3.920% at December 31, 2018) 2018 term loan facility, due April 2023	\$ —	\$ — ⁽¹⁾	\$ —	\$ —
4.05% Senior Notes due January 2020 ⁽²⁾	52	—	—	52
4.10% Senior Notes due March 2022	213	(1)	—	212
4.95% Senior Notes due January 2025 ⁽²⁾	927	(7)	(1)	919
7.50% Senior Notes due April 2026	650	(8)	—	642
7.75% Senior Notes due October 2027	500	(7)	—	493
Total long-term debt	<u>\$ 2,342</u>	<u>\$ (23)</u>	<u>\$ (1)</u>	<u>\$ 2,318</u>

- (1) At December 31, 2019 and 2018, unamortized issuance expense of \$11 million associated with the 2018 revolving credit facility was classified as other long-term assets on the consolidated balance sheet.
- (2) In February and June 2016, Moody's and S&P downgraded certain senior notes, increasing the interest rates by 175 basis points effective July 2016. As a result of the downgrades, interest rates increased to 5.80% for the 2020 Notes and 6.70% for the 2025 Notes. S&P and Moody's upgraded certain senior notes in April and May 2018, respectively. As a result of these upgrades, interest rates decreased to 5.30% for the 2020 Notes and 6.20% for the 2025 Notes effective July 2018. The first coupon payment to the bondholders at the lower interest rate was paid in January 2019.

The following is a summary of scheduled debt maturities by year as of December 31, 2019:

<i>(in millions)</i>	
2020	\$ —
2021	—
2022	213
2023	—
2024 ⁽¹⁾	34
Thereafter	2,015
	<u>\$ 2,262</u>

- (1) The Company's current revolving credit facility matures in 2024.

Credit Facilities

2016 Credit Facility

In June 2016, the Company reduced its \$2.0 billion unsecured revolving credit facility entered into in December 2013 to \$66 million and entered into a new credit agreement for \$1,934 million, consisting of a \$1,191 million secured term loan and a new \$743 million unsecured revolving credit facility, maturing in December 2020.

Concurrent with the closing of the 2018 credit facility agreement in April 2018, the Company repaid the \$1,191 million secured term loan balance and recognized a loss on early debt extinguishment of \$8 million on the consolidated income statement related to the unamortized issuance expense. In addition, approximately \$4 million of unamortized issuance expense associated with the closed \$743 million revolving credit facility was carried forward into the unamortized issuance expenses of the 2018 credit facility.

2018 Credit Facility

In April 2018, the Company replaced its credit facility entered into in 2016 with a new revolving credit facility (the “2018 credit facility”). The 2018 credit facility has an aggregate maximum revolving credit amount of \$3.5 billion with a current aggregate commitment of \$2.0 billion and borrowing base (limit on availability) that is redetermined at least each April and October. The 2018 credit facility is secured by substantially all of the assets owned by the Company and its subsidiaries. The permitted lien provisions in the senior notes indentures currently limit liens securing indebtedness to the greater of \$2.0 billion and 25% of adjusted consolidated net tangible assets. On October 8, 2019, the Company entered into an amendment to the 2018 credit facility that, among other things, established the October 2019 borrowing base at \$2.1 billion and extended the maturity date to April 2024.

Loans under the 2018 credit facility are subject to varying rates of interest based on whether the loan is a Eurodollar loan or an alternate base rate loan. Eurodollar loans bear interest at the Eurodollar rate, which is adjusted LIBOR for such interest period plus the applicable margin (as those terms are defined in the 2018 credit facility documentation). The applicable margin for Eurodollar loans under the 2018 credit facility ranges from 1.50% to 2.50% based on the Company’s utilization of the borrowing base under the 2018 credit facility. Alternate base rate loans bear interest at the alternate base rate plus the applicable margin. The applicable margin for alternate base rate loans under the 2018 credit facility ranges from 0.50% to 1.50% based on the Company’s utilization of the borrowing base under the 2018 credit facility.

The 2018 credit facility contains customary representations and warranties and covenants including, among others, the following:

- a prohibition against incurring debt, subject to permitted exceptions;
- a restriction on creating liens on assets, subject to permitted exceptions;
- restrictions on mergers and asset dispositions;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business; and
- maintenance of the following financial covenants, commencing with the fiscal quarter ended June 30, 2018:
 - (1) Minimum current ratio of no less than 1.00 to 1.00, whereby current ratio is defined as the Company’s consolidated current assets (including unused commitments under the credit agreement, but excluding non-cash derivative assets) to consolidated current liabilities (excluding non-cash derivative obligations and current maturities of long-term debt).
 - (2) Maximum total net leverage ratio of no greater than (i) with respect to each fiscal quarter ending during the period from June 30, 2018 through March 31, 2019, 4.50 to 1.00, (ii) with respect to each fiscal quarter ending during the period from June 30, 2019 through March 31, 2020, 4.25 to 1.00, and (iii) with respect to each fiscal quarter ending on or after June 30, 2020, 4.00 to 1.00. Total net leverage ratio is defined as total debt less cash on hand (up to the lesser of 10% of credit limit or \$150 million) divided by consolidated EBITDAX for the last four consecutive quarters. EBITDAX, as defined in the Company’s 2018 credit agreement, excludes the effects of interest expense, depreciation, depletion and amortization, income tax, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs.

The 2018 credit facility contains customary events of default that include, among other things, the failure to comply with the financial covenants described above, non-payment of principal, interest or fees, violation of covenants, inaccuracy of representations and warranties, bankruptcy and insolvency events, material judgments and cross-defaults to material indebtedness. If an event of default occurs and is continuing, all amounts outstanding under the 2018 credit facility may become immediately due and payable. As of December 31, 2019, the Company was in compliance with all of the covenants of the credit agreement in all material respects.

Each United States domestic subsidiary of the Company for which the Company owns 100% of its equity guarantees the 2018 credit facility. Pursuant to requirements under the indentures governing its senior notes, each subsidiary that became a guarantor of the 2018 credit facility also became a guarantor of each of the Company's senior notes. See Note 16 for the Company's Condensed Consolidated Financial Information, presented in accordance with Rule 3-10 of Regulation S-X.

As of December 31, 2019, the Company had \$172 million in letters of credit and \$34 million in borrowings outstanding under the 2018 credit facility.

Senior Notes

In January 2015, the Company completed a public offering of \$850 million aggregate principal amount of its 4.05% Senior Notes due 2020 (the "2020 Notes") and \$1.0 billion aggregate principal amount of its 4.95% Senior Notes due 2025 (the "2025 Notes" together with the 2020 Notes, the "Notes"). The interest rates on the Notes are determined based upon the public bond ratings from Moody's and S&P. Downgrades on the Notes from either rating agency increase interest costs by 25 basis points per downgrade level and upgrades decrease interest costs by 25 basis points per upgrade level, up to the stated coupon rate, on the following semi-annual bond interest payment. In February and June 2016, Moody's and S&P downgraded the Notes, increasing the interest rates by 175 basis points effective July 2016. As a result of these downgrades, interest rates increased to 5.80% for the 2020 Notes and 6.70% for the 2025 Notes. In the event of future downgrades, the coupons for this series of notes were capped at 6.05% and 6.95%, respectively. The first coupon payment to the bondholders at the higher interest rates was paid in January 2017. S&P and Moody's subsequently upgraded the Notes in April and May 2018, respectively. As a result of these upgrades, interest rates decreased to 5.30% for the 2020 Notes and 6.20% for the 2025 Notes effective July 2018. The first coupon payment to bondholders at the lower interest rates was paid in January 2019.

As discussed in Note 3 above, in December 2018, the Company closed the Fayetteville Shale sale and used a portion of the proceeds to repurchase \$40 million of its 4.05% Senior Notes due January 2020, \$787 million of its 4.10% Senior Notes due March 2022 and \$73 million of its 4.95% Senior Notes due January 2025. The Company recognized a loss on extinguishment of debt of \$9 million, which included \$2 million of premiums paid.

In the second half of 2019, the Company repurchased \$35 million of its 4.95% senior notes due 2025, \$11 million of its 7.50% Senior Notes due 2026 and \$16 million of its 7.75% Senior Notes due 2027 at a discount for \$54 million, and recognized an \$8 million gain on extinguishment of debt. Additionally, in December 2019, the Company retired the remaining \$52 million principal of its 4.05% Senior Notes due January 2020.

(10) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of December 31, 2019, the Company's contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately \$8.5 billion, \$1.1 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. The Company also had guarantee obligations of up to \$293 million of that amount. As of December 31, 2019, future payments under non-cancelable firm transportation and gathering agreements are as follows:

<i>(in millions)</i>	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
Infrastructure currently in service	\$ 7,414	\$ 767	\$ 1,200	\$ 1,066	\$ 1,531	\$ 2,850
Pending regulatory approval and/or construction ⁽¹⁾	1,056	1	35	103	208	709
Total transportation charges	\$ 8,470	\$ 768	\$ 1,235	\$ 1,169	\$ 1,739	\$ 3,559

(1) Based on the estimated in-service dates as of December 31, 2019.

In December 2018, the Company closed on the Fayetteville Shale sale and retained certain contractual commitments related to firm transportation, with the buyer obligated to pay the transportation provider directly for these charges. As of December 31,

2019, approximately \$108 million of these contractual commitments remain of which the Company will reimburse the buyer for certain of these potential obligations up to approximately \$58 million through December 2020 depending on the buyer's actual use, and has recorded a \$46 million liability for the estimated future payments, reduced from \$88 million at December 31, 2018.

The Company leases pressure pumping equipment for its E&P operations under a single lease that expires in 2021. The current aggregate annual payment under this lease is approximately \$6 million. The Company has seven leases for drilling rigs for its E&P operations that expire through 2024 with a current aggregate annual payment of approximately \$13 million. The lease payments for the pressure pumping equipment, as well as other operating expenses for the Company's drilling operations, are capitalized to natural gas and oil properties and are partially offset by billings to third-party working interest owners.

The Company leases office space, vehicles and equipment under non-cancelable operating leases expiring through 2029. As of December 31, 2019, future minimum payments under these non-cancelable leases accounted for as operating leases (including short-term) are approximately \$33 million in 2020, \$24 million in 2021, \$18 million in 2022, \$16 million in 2023, \$12 million in 2024 and \$45 million thereafter.

The Company also has commitments for compression services and compression rentals related to its E&P segment. As of December 31, 2019, future minimum payments under these non-cancelable agreements (including short-term obligations) are approximately \$13 million in 2020, \$13 million in 2021, \$9 million in 2022 and \$2 million in 2023.

In the first quarter of 2019, the Company agreed to purchase firm transportation with pipelines in the Appalachian basin starting in 2021 and running through 2032 totaling \$357 million in total contractual commitments, which is presented in the table above; the seller has agreed to reimburse \$133 million of these commitments.

In February 2020, the Company was notified that the proposed Constitution pipeline project was cancelled and that the Company was released from a firm transportation agreement with its sponsor. As of December 31, 2019, the Company had contractual commitments totaling \$512 million over the next seventeen years related to the Constitution pipeline project that are reflected in the table above as pending regulatory approval and/or construction. These amounts are \$6 million within one to three years, \$68 million within three to five years, \$102 million within five to eight years and \$336 million more than eight years forward.

Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position, results of operations or cash flows of the Company.

Litigation

The Company is subject to various litigation, claims and proceedings, most of which have arisen in the ordinary course of business such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic accidents, pollution, contamination, encroachment on others' property or nuisance. The Company accrues for litigation, claims and proceedings when a liability is both probable and the amount can be reasonably estimated. As of December 31, 2019, the Company does not currently have any material amounts accrued related to litigation matters. For any matters not accrued for, it is not possible at this time to estimate the amount of any additional loss, or range of loss that is reasonably possible, but, based on the nature of the claims, management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on the Company's financial position, results of operations or cash flows, for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future.

Arkansas Royalty Litigation

The Company was a defendant in three certified class actions alleging that the Company underpaid lessors of lands in Arkansas by deducting from royalty payments costs for gathering, transportation and compression of natural gas in excess of what is permitted by the relevant leases. Two of these class actions were filed in Arkansas state courts and the third in the United States District court for the Eastern District of Arkansas. The Company denied liability in all three cases.

In 2017, the jury returned a verdict in favor of the Company on all counts in *Smith v. SEECO, Inc. et al.*, the class action in the federal court, whose plaintiff class comprised the vast majority of the lessors in these cases. The plaintiff had asserted claims for, among other things, breach of contract, fraud, civil conspiracy, unjust enrichment and violation of certain Arkansas statutes. Following the verdict, the court entered judgment in favor of the Company on all claims. The trial court denied the plaintiff's motion for a new trial, and the plaintiff appealed to the United States Court of Appeals for the Eighth Circuit. Independent of

the plaintiff's appeal, several different parties sought to intervene in the *Smith* case prior to or shortly after trial, and have appealed the trial court's order denying their request to intervene. Oral argument occurred in January 2019. On April 23, 2019, the Court of Appeals affirmed the trial court's order denying all requests to intervene in the case, and, in a separate order, affirmed the trial court's judgment in favor of the Company on all claims. The Court of Appeals subsequently denied all requests for rehearing.

In 2018, the company entered into an agreement to settle another of the class actions, which was pending in the Circuit Court of Conway County, Arkansas under the caption *Snow, et al v. SEECO, Inc., et al.* The settlement received final approval by the court and the deadline to appeal the order approving the settlement passed without any appeals filed. The amount of the settlement was reflected in the Company's consolidated statement of operations for 2018 and has been paid. The third class action was also dismissed in 2018.

As of December 31, 2019, some actions filed on behalf of mineral interest owners who opted out of the class actions mentioned above remain pending. The Company does not expect those cases to have a material adverse effect on the results of operations, financial position or cash flows of the Company. Additionally, it is not possible at this time to estimate the amount of any additional loss, or range of loss, that is reasonably possible.

St. Lucie County Fire District Firefighters' Pension Trust

On October 17, 2016, the St. Lucie County Fire District Firefighters' Pension Trust filed a putative class action in the 61st District Court in Harris County, Texas, against the Company, certain of its former officers and current and former directors and the underwriters on behalf of itself and others that purchased certain depository shares from the Company's January 2015 equity offering, alleging material misstatements and omissions in the registration statement for that offering. The Company removed the case to federal court, but after a decision by the United States Supreme Court in an unrelated case that these types of cases are not subject to removal, the federal court remanded the case to the Texas state court. The Texas trial court denied the Company's motion to dismiss, and in February 2020, the court of appeals declined to exercise discretion to reverse the trial court's decision. The Company carries insurance for the claims asserted against it and the officer and director defendants, and the carrier has accepted coverage. The Company denies all allegations and intend to continue to defend this case vigorously. The Company does not expect this case to have a material adverse effect on the results of operations, financial position or cash flows of the Company. Additionally, it is not possible at this time to estimate the amount of any additional loss, or range of loss, that is reasonably possible.

Indemnifications

The Company has provided certain indemnifications to various third parties, including in relation to asset and entity dispositions, securities offerings and other financings, such as the St. Lucie County Fire District Firefighters' Pension Trust case described above. In the case of asset dispositions, these indemnifications typically relate to disputes, litigation or tax matters existing at the date of disposition. The Company likewise obtains indemnification for future matters when it sells assets, although there is no assurance the buyer will be capable of performing those obligations. In the case of equity offerings, these indemnifications typically relate to claims asserted against underwriters in connection with an offering. No material liabilities have been recognized in connection with these indemnifications.

(11) INCOME TAXES

The provision (benefit) for income taxes included the following components:

<i>(in millions)</i>	<u>2019</u>	<u>2018</u>	<u>2017</u>
Current:			
Federal	\$ (1)	\$ (5)	\$ (22)
State	(1)	6	—
	<u>(2)</u>	<u>1</u>	<u>(22)</u>
Deferred:			
Federal	(431)	—	(71)
State	22	—	—
	<u>(409)</u>	<u>—</u>	<u>(71)</u>
Provision (benefit) for income taxes	<u>\$ (411)</u>	<u>\$ 1</u>	<u>\$ (93)</u>

The provision for income taxes was an effective rate of (86)% in 2019, 0% in 2018 and (10)% in 2017. The Company's effective tax rate decreased in 2019, as compared with 2018, primarily due to the release of a valuation allowance in 2019. The

following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

<i>(in millions)</i>	<u>2019</u>	<u>2018</u>	<u>2017</u>
Expected provision at federal statutory rate	\$ 101	\$ 113	\$ 333
Decrease resulting from:			
State income taxes, net of federal income tax effect	11	13	16
Rate impacts due to tax reform	—	—	370
Changes to valuation allowance due to tax reform	—	—	(370)
AMT tax reform impact – valuation allowance release	—	—	(68)
Changes in uncertain tax positions	—	—	(5)
Change in valuation allowance	(522)	(121)	(364)
Removal of sequestration fee on AMT receivables	—	(5)	—
Other	(1)	1	(5)
Provision (benefit) for income taxes	<u>\$ (411)</u>	<u>\$ 1</u>	<u>\$ (93)</u>

The 2019 tax accrual calculated under the estimated annual effective tax rate method reflects the Tax Reform Act changes that took effect January 1, 2018. The components of the Company's deferred tax balances as of December 31, 2019 and 2018 were as follows:

<i>(in millions)</i>	<u>2019</u>	<u>2018</u>
Deferred tax liabilities:		
Differences between book and tax basis of property	\$ 312	\$ 226
Derivative activity	34	12
Right of use lease asset	37	—
Other	2	2
	<u>385</u>	<u>240</u>
Deferred tax assets:		
Accrued compensation	33	33
Accrued pension costs	9	10
Asset retirement obligations	13	15
Net operating loss carryforward	769	777
Future lease payments	37	—
Other	18	14
	<u>879</u>	<u>849</u>
Valuation allowance	<u>(87)</u>	<u>(609)</u>
Net deferred tax asset	<u>\$ 407</u>	<u>\$ —</u>

The Tax Reform Act made significant changes to the U.S. federal income tax law affecting the Company. Major changes in this legislation applicable to the Company relate to the reduction in the corporate tax rate to 21%, repeal of the alternative minimum tax, interest deductibility and net operating loss carryforward limitations, changes to certain executive compensation and full expensing provisions related to business assets. The adjustments required to deferred taxes as a result of the Tax Reform Act have been reflected in the Company's tax provision.

As the Tax Reform Act repealed the corporate alternative minimum tax for tax years beginning on or after January 1, 2018 and provided for existing alternative minimum tax credit carryovers to be refunded beginning in 2018, the Company has approximately \$30 million in refundable credits remaining that are expected to be fully refunded by 2021. Accordingly, in 2017 the valuation allowance in place prior to the Tax Reform Act related to these credits was released, and any credits remaining were reclassified to a receivable.

In 2019, the Company received refunds related to state income tax of \$1.0 million. In 2018, the Company paid \$6.3 million in state income tax. The Company's net operating loss carryforward as of December 31, 2019 was \$3.0 billion and \$2.3 billion for federal and state reporting purposes, respectively, the majority of which will expire between 2035 and 2039. Additionally, the Company has an income tax net operating loss carryforward related to its Canadian operations of \$29 million, with expiration dates of 2030 through 2038. The Company also had a statutory depletion carryforward of \$13 million and \$29 million related to interest deduction carryforward as of December 31, 2019.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized. To assess that likelihood, the Company uses estimates and judgment regarding future taxable income, and considers the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include current financial position, results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as current and forecasted business economics of the oil and gas industry.

For the years ended December 31, 2018 and 2017, the Company maintained a full valuation allowance against its deferred tax assets based on its conclusion, considering all available evidence (both positive and negative), that it was more likely than not that the deferred tax assets would not be realized. A significant item of objective negative evidence considered was the cumulative pre-tax loss incurred over the three-year period ended December 31, 2018, primarily due to non-cash impairments of proved natural gas and oil properties recognized in 2015 and 2016. As of the first quarter of 2019, the Company had sustained a three-year cumulative level of profitability. Based on this factor and other positive evidence including forecasted taxable income, the Company concluded that it was more likely than not that the deferred tax assets would be realized and determined that \$522 million of the valuation allowance would be released during 2019. Accordingly, a tax benefit of \$522 million was recorded. As of December 31, 2019, the Company expects to retain a valuation allowance of \$87 million related to net operating losses in jurisdictions in which it no longer operates. The Company is continually evaluating deferred tax asset realizability, and if pricing changes occur that would significantly affect the forecast, the Company will reconsider the need for a valuation allowance at such time.

A reconciliation of the changes to the valuation allowance is as follows:

(in millions)

Valuation allowance as of December 31, 2018	\$ 609
Release of valuation allowance in 2019	<u>(522)</u>
Valuation allowance as of December 31, 2019	<u>\$ 87</u>

A tax position must meet certain thresholds for any of the benefit of the uncertain tax position to be recognized in the financial statements. As of December 31, 2019, there were no unrecognized tax positions identified that would have a material effect on the effective tax rate. All positions booked as of December 31, 2018 were released in 2019 due to audit completion and statute expirations.

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

(in millions)

	<u>2019</u>	<u>2018</u>
Unrecognized tax benefits at beginning of year	\$ 7	\$ 12
Additions based on tax positions related to the current year	—	—
Additions to tax positions of prior years	—	—
Reductions to tax positions of prior years	<u>(7)</u>	<u>(5)</u>
Unrecognized tax benefits at end of year	<u>\$ —</u>	<u>\$ 7</u>

The Internal Revenue Service closed the 2014 audit of the Company's federal return in 2019 with no change and is currently auditing the Company's 2016 and 2017 tax periods. The income tax years 2016 to 2019 remain open to examination by the major taxing jurisdictions to which the Company is subject.

(12) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2019 and 2018 activity related to asset retirement obligations:

<i>(in millions)</i>	2019	2018
Asset retirement obligation at January 1	\$ 61	\$ 165
Accretion of discount	3	9
Obligations incurred	2	1
Obligations settled/removed ⁽¹⁾	(9)	(116)
Revisions of estimates	—	2
Asset retirement obligation at December 31	<u>\$ 57</u>	<u>\$ 61</u>
Current liability	\$ 6	\$ 6
Long-term liability	51	55
Asset retirement obligation at December 31	<u>\$ 57</u>	<u>\$ 61</u>

(1) Obligations settled/removed include \$111 million related to asset divestitures in 2018, of which \$107 million related to the Fayetteville Shale sale.

(13) RETIREMENT AND EMPLOYEE BENEFIT PLANS

401(k) Defined Contribution Plan

The Company has a 401(k) defined contribution plan covering eligible employees. The Company expensed \$2 million, \$3 million and \$3 million of contribution expense in 2019, 2018 and 2017, respectively. Additionally, the Company capitalized \$1 million of contributions in 2019 and \$2 million in both 2018 and 2017, directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties or directly related to the construction of the Company's gathering systems.

Defined Benefit Pension and Other Postretirement Plans

Prior to January 1, 1998, the Company maintained a traditional defined benefit plan with benefits payable based upon average final compensation and years of service. Effective January 1, 1998, the Company amended its pension plan to become a "cash balance" plan on a prospective basis for its non-bargaining employees. A cash balance plan provides benefits based upon a fixed percentage of an employee's annual compensation. The Company's funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plan provides contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages.

Substantially all of the Company's employees are covered by the defined benefit pension and postretirement benefit plans. The Company accounts for its defined benefit pension and other postretirement plans by recognizing the funded status of each defined pension benefit plan and other postretirement benefit plan on the Company's balance sheet. In the event a plan is overfunded, the Company recognizes an asset. Conversely, if a plan is underfunded, the Company recognizes a liability.

In June 2018, the Company notified affected employees of a workforce reduction plan, which resulted primarily from a previously announced study of structural, process and organizational changes to enhance shareholder value. In December 2018, the Company closed the sale of the equity in certain of its subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, many employees associated with those assets were either transferred to the buyer or their employment was terminated. As a result of the restructurings, the Company recognized a curtailment on its pension and other postretirement benefit plans and recognized a non-cash gain of \$4 million on its consolidated statements of operations for the year ended December 31, 2018. In 2019, the Company recognized a \$6 million non-cash settlement loss related to \$21 million of lump sum payments as a result of these restructuring events.

The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets and funded status as of December 31, 2019 and 2018:

<i>(in millions)</i>	Pension Benefits		Other Postretirement Benefits	
	2019	2018	2019	2018
Change in benefit obligations:				
Benefit obligation at January 1	\$ 125	\$ 143	\$ 13	\$ 17
Service cost	7	10	1	2
Interest cost	5	5	—	1
Participant contributions	—	—	—	—
Actuarial (gain) loss	15	(14)	1	—
Benefits paid	(2)	(14)	(2)	(1)
Plan amendments	—	—	—	—
Curtailements	—	(5)	—	(6)
Settlements	(24)	—	—	—
Benefit obligation at December 31	<u>\$ 126</u>	<u>\$ 125</u>	<u>\$ 13</u>	<u>\$ 13</u>

<i>(in millions)</i>	Pension Benefits		Other Postretirement Benefits	
	2019	2018	2019	2018
Change in plan assets:				
Fair value of plan assets at January 1	\$ 91	\$ 101	\$ —	\$ —
Actual return on plan assets	16	(8)	—	—
Employer contributions	12	12	2	1
Participant contributions	—	—	—	—
Benefits paid	(2)	(14)	(2)	(1)
Settlements	(21)	—	—	—
Fair value of plan assets at December 31	<u>\$ 96</u>	<u>\$ 91</u>	<u>\$ —</u>	<u>\$ —</u>
Funded status of plans at December 31	<u>\$ (30)</u>	<u>\$ (34)</u>	<u>\$ (13)</u>	<u>\$ (13)</u>

The Company uses a December 31 measurement date for all of its plans and had liabilities recorded for the underfunded status for each period as presented above.

The pension plans' projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2019 and 2018 are as follows:

<i>(in millions)</i>	2019	2018
Projected benefit obligation	\$ 126	\$ 125
Accumulated benefit obligation	124	122
Fair value of plan assets	96	91

Pension and other postretirement benefit costs include the following components for 2019, 2018 and 2017:

<i>(in millions)</i>	Pension Benefits			Other Postretirement Benefits		
	2019	2018	2017	2019	2018	2017
Service cost	\$ 7	\$ 10	\$ 9	\$ 1	\$ 2	\$ 2
Interest cost	5	5	5	—	1	—
Expected return on plan assets	(6)	(7)	(6)	—	—	—
Amortization of transition obligation	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	—	—
Amortization of net loss	2	2	2	—	—	—
Net periodic benefit cost	<u>8</u>	<u>10</u>	<u>10</u>	<u>1</u>	<u>3</u>	<u>2</u>
Curtailement gain	—	—	—	—	(4)	—
Settlement loss	6	—	—	—	—	—
Total benefit cost (benefit)	<u>\$ 14</u>	<u>\$ 10</u>	<u>\$ 10</u>	<u>\$ 1</u>	<u>\$ (1)</u>	<u>\$ 2</u>

Service cost is classified as general and administrative expenses on the consolidated statements of operations. All other components of total benefit cost (benefit) are classified as other income (loss), net on the consolidated statements of operations.

Amounts recognized in other comprehensive income for the years ended December 31, 2019 and 2018 were as follows:

<i>(in millions)</i>	Pension Benefits		Other Postretirement Benefits	
	2019	2018	2019	2018
Net actuarial loss arising during the year	\$ (5)	\$ (2)	\$ (1)	\$ —
Amortization of prior service cost	—	—	—	—
Amortization of net loss	2	2	—	—
Settlements	8	—	—	—
Curtailments	—	5	—	3
Tax effect ⁽¹⁾	(1)	(1)	—	(1)
	<u>\$ 4</u>	<u>\$ 4</u>	<u>\$ (1)</u>	<u>\$ 2</u>

(1) For the year ended December 31, 2018, deferred tax activity related to pension and other postretirement benefits was offset by a valuation allowance, resulting in no tax expense presented on the consolidated statements of operations.

Included in accumulated other comprehensive income as of December 31, 2019 and 2018 was a \$30 million loss (\$22 million net of tax) and a \$34 million loss (\$20 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans. For the year ended December 31, 2019, \$3 million was classified from accumulated other comprehensive income, primarily driven by settlement losses. Amortization of prior period service cost reclassified from accumulated other comprehensive income to general and administrative expenses for the year was immaterial.

The amount in accumulated other comprehensive income that is expected to be recognized as a component of net periodic benefit cost during 2020 is a \$1 million expense.

The assumptions used in the measurement of the Company's benefit obligations as of December 31, 2019 and 2018 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2019	2018	2019	2018
Discount rate	3.70 %	4.35 %	3.50 %	4.35 %
Rate of compensation increase	3.50 %	3.50 %	n/a	n/a

The assumptions used in the measurement of the Company's net periodic benefit cost for 2019, 2018 and 2017 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2019	2018	2017	2019	2018	2017
Discount rate	3.70 %	4.35 %	4.20 %	4.35 %	4.35 %	4.20 %
Expected return on plan assets	7.00 %	7.00 %	7.00 %	n/a	n/a	n/a
Rate of compensation increase	3.50 %	3.50 %	3.50 %	n/a	n/a	n/a

The expected return on plan assets for the various benefit plans is based upon a review of the historical returns experienced, combined with the future expected returns based upon the asset allocation strategy employed. The plans seek to achieve an adequate return to fund the obligations in a manner consistent with the federal standards of the Employee Retirement Income Security Act and with a prudent level of diversification.

For measurement purposes, the following trend rates were assumed for 2019 and 2018:

	2019	2018
Health care cost trend assumed for next year	7 %	7 %
Rate to which the cost trend is assumed to decline	5 %	5 %
Year that the rate reaches the ultimate trend rate	2037	2036

Assumed health care cost trend rates have a significant effect on the amounts for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

<i>(in millions)</i>	1% Increase	1% Decrease
Effect on the total service and interest cost components	\$ 2	\$ (1)
Effect on postretirement benefit obligations	\$ 2	\$ (2)

Pension Payments and Asset Management

In 2019, the Company contributed \$12 million to its pension plans and \$2 million to its other postretirement benefit plan. The Company expects to contribute \$13 million to its pension and other postretirement benefit plans in 2020.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Pension Benefits		Other Postretirement Benefits	
<i>(in millions)</i>			
2020	\$ 5	2020	\$ 1
2021	5	2021	1
2022	6	2022	1
2023	6	2023	1
2024	7	2024	1
Years 2025-2029	34	Years 2025-2029	5

The Company's overall investment strategy is to provide an adequate pool of assets to support both the long-term growth of plan assets and to ensure adequate liquidity exists for the near-term payment of benefit obligations to participants, retirees and beneficiaries. The Benefits Administration Committee of the Company, appointed by the Compensation Committee of the Board of Directors, administers the Company's pension plan assets. The Benefits Administration Committee believes long-term investment performance is a function of asset-class mix and restricts the composition of pension plan assets to a combination of cash and cash equivalents, domestic equity markets, international equity markets or investment grade fixed income assets.

The table below presents the allocations targeted by the Benefits Administration Committee and the actual weighted-average asset allocation of the Company's pension plan as of December 31, 2019, by asset category. The asset allocation targets are subject to change and the Benefits Administration Committee allows for its actual allocations to deviate from target as a result of current and anticipated market conditions. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

Asset category:	Pension Plan Asset Allocations	
	Target	Actual
Equity securities:		
U.S. equity ⁽¹⁾	35 %	34 %
Non-U.S. equity ⁽²⁾	35 %	33 %
Fixed income ⁽³⁾	28 %	31 %
Cash ⁽⁴⁾	2 %	2 %
Total	100 %	100 %

(1) Includes the following equity securities in the table below: U.S. large cap growth equity, U.S. large cap value equity, U.S. large cap core equity, and U.S. small cap equity.

(2) Includes Non-U.S. equity securities in the table below.

(3) Includes fixed income pension plan assets in the table below.

(4) Includes Cash and cash equivalent pension plan assets in the table below.

Utilizing the fair value hierarchy described in Note 8, the Company's fair value measurement of pension plan assets as of December 31, 2019 is as follows:

<i>(in millions)</i>	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity ⁽¹⁾	\$ 3	\$ 3	\$ —	\$ —
U.S. large cap value equity ⁽²⁾	6	6	—	—
U.S. small cap equity ⁽³⁾	2	2	—	—
Non-U.S. equity ⁽⁴⁾	32	32	—	—
Fixed income ⁽⁶⁾	22	22	—	—
Cash and cash equivalents	2	2	—	—
Total measured within fair value hierarchy	\$ 67	\$ 67	\$ —	\$ —
Measured at net asset value ⁽⁸⁾				
Equity securities:				
U.S. large cap growth equity ⁽⁹⁾	3			
U.S. large cap core equity ⁽¹⁰⁾	18			
Fixed income ⁽⁶⁾	8			
Total measured at net asset value	\$ 29			
Total plan assets at fair value	\$ 96			

Note: Footnotes are located after the prior year comparative table below.

Utilizing the fair value hierarchy described in Note 8, the Company's fair value measurement of pension plan assets at December 31, 2018 was as follows:

<i>(in millions)</i>	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity ⁽¹⁾	\$ 5	\$ 5	\$ —	\$ —
U.S. large cap value equity ⁽²⁾	5	5	—	—
U.S. small cap equity ⁽³⁾	2	2	—	—
Non-U.S. equity ⁽⁴⁾	20	20	—	—
Emerging markets equity ⁽⁵⁾	3	3	—	—
Fixed income ⁽⁶⁾	14	14	—	—
Cash and cash equivalents ⁽⁷⁾	23	23	—	—
Total measured within fair value hierarchy	\$ 72	\$ 72	\$ —	\$ —
Measured at net asset value ⁽⁸⁾				
Equity securities:				
U.S. large cap core equity ⁽¹⁰⁾	12			
Fixed income ⁽⁶⁾	7			
Total measured at net asset value	\$ 19			
Total plan assets at fair value	\$ 91			

- (1) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.
- (2) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.
- (3) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
- (4) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
- (5) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
- (6) Institutional funds that seek an investment return that approximates, as closely as practicable, before expenses, the performance of the Barclays U.S. Intermediate Credit Bond Index over the long term and the Barclays Long U.S. Corporate Bond Index over the long-term.
- (7) Included approximately \$21 million for anticipated lump sum distributions resulting from the Fayetteville Shale sale in December 2018.

- (8) Plan assets for which fair value was measured using net asset value as a practical expedient.
- (9) An institutional fund that seeks to invest in companies with sustainable competitive advantages, as identified through proprietary research.
- (10) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.

The Company's pension plan assets that are classified as Level 1 are the investments comprised of either cash or investments in open-ended mutual funds which produce a daily net asset value that is validated with a sufficient level of observable activity to support classification of the fair value measurement as Level 1. Due to the Company's implementation of Accounting Standards Update No. 2015-07, assets measured using net asset value as a practical expedient have not been classified in the fair value hierarchy. No concentration of risk arising within or across categories of plan assets exists due to any significant investments in a single entity, industry, country or investment fund.

(14) STOCK-BASED COMPENSATION

The Southwestern Energy Company 2013 Incentive Plan was adopted in February 2013, approved by stockholders in May 2013 and amended and restated per stockholders' approval in May 2016 and further amended in May 2017 and May 2019 (the "2013 Plan"). The 2013 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries.

The 2013 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units to employees, officers and directors that, in the aggregate, do not exceed 88,700,000 shares. The types of incentives that may be awarded are comprehensive and are intended to enable the Company's Board of Directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2013 Plan.

The Company's stock-based compensation is classified as either equity or liability awards in accordance with GAAP. The fair value of an equity-classified award is determined at the grant date and is amortized to general and administrative expense and capitalized expense on a straight-line basis over the vesting period of the award. The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense over the vesting period of the award. A portion of this general and administrative expense is capitalized into natural gas and oil properties, included in property and equipment. Generally, stock options granted to employees and directors vest ratably over three years from the grant date and expire seven years from the date of grant. The Company issues shares of restricted stock or restricted stock units to employees and directors which generally vest over four years. Restricted stock, restricted stock units and stock options granted to participants under the 2013 Plan, as amended and restated, immediately vest upon death, disability or retirement (subject to a minimum of three years of service). The Company issues performance units which have historically vested over three years to employees. The performance units granted in 2018 and 2019 cliff-vest at the end of three years.

In June 2018, the Company announced a workforce reduction. Unvested stock-based awards of the affected employees were subsequently cancelled and the approximate fair value of a portion of those cancelled awards was included in a cash severance payment that was paid in the third quarter of 2018. Stock-based compensation costs recognized prior to the cancellation as either general and administrative expense or capitalized expense were reversed and the severance payments were subsequently recognized as restructuring charges for the year ended December 31, 2018 on the consolidated statements of operations.

In December 2018, the Company closed the Fayetteville Shale sale. As part of this transaction, most employees associated with those assets became employees of the buyer although the employment of some was terminated. All affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. Stock-based compensation costs recognized prior to the cancellation as either general and administrative expense or capitalized expense were reversed and the severance payments were subsequently recognized as restructuring charges for the years ended December 31, 2019 and 2018 on the consolidated statements of operations.

Equity-Classified Awards

Equity-Classified Stock Options

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2019, 2018 and 2017:

<i>(in millions)</i>	2019	2018	2017
Stock options – general and administrative expense	\$ 1	\$ 2	\$ 3
Stock options – general and administrative expense capitalized	\$ —	\$ —	\$ 1

The Company also recorded a reduction in the deferred tax asset of less than \$1 million related to stock options for the year ended December 31, 2019, compared to deferred tax assets of less than \$1 million and \$1 million for the years ended December 31, 2018 and 2017, respectively. Unrecognized compensation cost related to the Company's unvested stock options totaled less than \$1 million at December 31, 2019. This cost is expected to be recognized over a weighted-average period of less than one year.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on the exercise of stock options, post-vesting forfeitures and other factors to estimate the expected term of the stock-based payments granted. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant. The Company did not issue equity-classified stock options in 2019 or 2018.

<u>Assumptions</u>	<u>2017</u>
Risk-free interest rate	1.9 %
Expected dividend yield	—
Expected volatility	50.5 %
Expected term	5 years

The following tables summarize stock option activity for the years 2019, 2018 and 2017, and provide information for options outstanding at December 31 of each year:

	<u>2019</u>		<u>2018</u>		<u>2017</u>	
	<u>Number of Shares</u>	<u>Weighted Average Exercise Price</u>	<u>Number of Shares</u>	<u>Weighted Average Exercise Price</u>	<u>Number of Shares</u>	<u>Weighted Average Exercise Price</u>
	<i>(in thousands)</i>		<i>(in thousands)</i>		<i>(in thousands)</i>	
Options outstanding at January 1	5,178	\$ 17.06	6,020	\$ 19.43	5,416	\$ 23.46
Granted	—	\$ —	—	\$ —	1,604	\$ 8.00
Exercised	—	\$ —	—	\$ —	—	\$ —
Forfeited or expired	<u>(543)</u>	<u>\$ 32.38</u>	<u>(842)</u>	<u>\$ 33.99</u>	<u>(1,000)</u>	<u>\$ 22.93</u>
Options outstanding at December 31	<u>4,635</u>	<u>\$ 15.26</u>	<u>5,178</u>	<u>\$ 17.06</u>	<u>6,020</u>	<u>\$ 19.43</u>

Range of Exercise Prices	<u>Options Outstanding</u>			<u>Options Exercisable</u>		
	Options Outstanding at December 31, 2019	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable at December 31, 2019	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	<i>(in thousands)</i>		<i>(years)</i>	<i>(in thousands)</i>		<i>(years)</i>
\$5.22-\$29.42	3,467	\$ 8.63	3.4	3,045	\$ 8.74	3.3
\$30.59-\$35.64	644	\$ 30.60	1.9	644	\$ 30.60	1.9
\$38.20-\$38.97	434	\$ 38.97	0.9	434	\$ 38.97	0.9
\$46.55-\$46.55	90	\$ 46.55	1.4	90	\$ 46.55	1.4
	<u>4,635</u>	<u>\$ 15.26</u>	<u>2.9</u>	<u>4,213</u>	<u>\$ 16.01</u>	<u>2.8</u>

No options were granted in 2019 or 2018. The weighted-average grant date fair value of options granted during 2017 was \$3.47. No options were exercised in 2019, 2018 or 2017.

Equity-Classified Restricted Stock

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2019, 2018 and 2017:

<i>(in millions)</i>	<u>2019</u>	<u>2018</u>	<u>2017</u>
Restricted stock grants – general and administrative expense	\$ 6	\$ 9	\$ 16
Restricted stock grants – general and administrative expense capitalized	\$ 4	\$ 5	\$ 11

The Company also recorded a reduction in the deferred tax asset of less than \$1 million related to restricted stock for the year ended December 31, 2019, compared to deferred tax assets of \$2 million and \$9 million for 2018 and 2017, respectively. As

of December 31, 2019, there was \$6 million of total unrecognized compensation cost related to unvested shares of restricted stock that is expected to be recognized over a weighted-average period of one year.

The following table summarizes the restricted stock activity for the years 2019, 2018 and 2017, and provides information for restricted stock outstanding at December 31 of each year:

	2019		2018		2017	
	Number of Shares (in thousands)	Weighted Average Fair Value	Number of Shares (in thousands)	Weighted Average Fair Value	Number of Shares (in thousands)	Weighted Average Fair Value
Unvested shares at January 1	2,717	\$ 7.91	6,254	\$ 8.85	3,321	\$ 11.85
Granted	493	\$ 3.06	350	\$ 4.72	5,055	\$ 8.38
Vested	(1,516)	\$ 7.16	(2,058)	\$ 9.24	(1,380)	\$ 13.28
Forfeited	(214) ⁽¹⁾	\$ 8.38	(1,829) ⁽²⁾	\$ 9.01	(742)	\$ 10.04
Unvested shares at December 31	<u>1,480</u>	\$ 7.00	<u>2,717</u>	\$ 7.91	<u>6,254</u>	\$ 8.85

(1) Includes 65,196 shares forfeited as a result of the reduction in workforce for the year ended December 31, 2019.

(2) Includes 1,287,636 shares forfeited as a result of the reduction in workforce for the year ended December 31, 2018.

The fair values of the grants were \$2 million for 2019, \$2 million for 2018 and \$42 million for 2017. The total fair value of shares vested were \$11 million for 2019, \$19 million for 2018 and \$18 million for 2017.

Equity-Classified Performance Units

The Company recorded compensation costs related to equity-classified performance units for the years ended December 31, 2019, 2018 and 2017. The performance units awarded in 2017 included a market condition based on relative Total Shareholder Return (“TSR”). The grant date fair value is calculated using the closing price of the Company’s common stock at the grant date and a Monte Carlo model to estimate the TSR market condition. The estimated fair value is amortized to compensation expense on a straight-line basis over the vesting period of the award. There were no equity-classified performance units awarded in 2019 and 2018.

	2019	2018	2017
Performance units – general and administrative expense	\$ 1	\$ 3	\$ 5
Performance units – general and administrative expense capitalized	\$ —	\$ 1	\$ 2

The Company also recorded a deferred tax asset of less than \$1 million related to equity-classified performance units for the year ended December 31, 2019, compared to deferred tax assets of \$1 million and \$3 million in 2018 and 2017, respectively. As of December 31, 2019, there was less than \$1 million of total unrecognized compensation cost related to unvested equity-classified performance units that is expected to be recognized over a weighted-average period of less than one year.

The following table summarizes equity-classified performance unit activity to be paid out in Company stock for the years ended December 31, 2019, 2018 and 2017, and provides information for unvested units as of December 31, 2019, 2018 and 2017:

	2019		2018		2017	
	Number of Units ⁽¹⁾ (in thousands)	Weighted Average Fair Value	Number of Units ⁽¹⁾ (in thousands)	Weighted Average Fair Value	Number of Units ⁽¹⁾ (in thousands)	Weighted Average Fair Value
Unvested shares at January 1	598	\$ 10.01	1,084	\$ 10.12	719	\$ 11.46
Granted	—	\$ —	—	\$ —	1,197	\$ 10.47
Vested	(378)	\$ 9.59	(290)	\$ 10.47	(325)	\$ 12.21
Forfeited	(42) ⁽²⁾	\$ 10.47	(196) ⁽³⁾	\$ 9.94	(507)	\$ 9.53
Unvested shares at December 31	<u>178</u>	\$ 10.47	<u>598</u>	\$ 10.01	<u>1,084</u>	\$ 10.12

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares may range from a minimum of zero shares to a maximum of two shares per unit contingent upon TSR. The performance units have a three-year vesting term and the actual disbursement of shares, if any, is determined during the first quarter following the end of the three-year vesting period.

(2) Includes 41,761 units related to the reduction in workforce for the year ended December 31, 2019.

(3) Includes 144,927 units related to the reduction in workforce for the year ended December 31, 2018.

Liability-Classified Awards

Liability-Classified Restricted Stock Units

In the first quarter of 2019 and 2018, the Company granted restricted stock units that vest over a period of four years and are payable in either cash or shares at the option of the Compensation Committee of the Company's Board of Directors. The Company has accounted for these as liability-classified awards, and accordingly changes in the market value of the instruments will be recorded to general and administrative expense and capitalized expense over the vesting period of the award.

(in millions)

	2019	2018
Restricted stock units – general and administrative expense	\$ 7	\$ 4
Restricted stock units – general and administrative expense capitalized	\$ 5	\$ 3

The Company also recorded deferred tax assets of less than \$1 million and \$2 million related to liability-classified restricted stock units for the years ended December 31, 2019 and 2018, respectively. As of December 31, 2019, there was \$24 million of total unrecognized compensation cost related to liability-classified restricted stock units that is expected to be recognized over a weighted-average period of three years. The amount of unrecognized compensation cost for liability-classified awards will fluctuate over time as they are marked to market.

The following table summarizes restricted stock unit activity to be paid out in cash for the years ended December 31, 2019 and 2018 and provides information for unvested units as of December 31, 2019 and 2018:

	2019		2018	
	Number of Units	Weighted Average Fair Value	Number of Units	Weighted Average Fair Value
	<i>(in thousands)</i>		<i>(in thousands)</i>	
Unvested units at January 1	8,202	\$ 3.41	—	\$ —
Granted	8,659	\$ 4.34	12,216	\$ 3.69
Vested	(2,624)	\$ 4.09	(232)	\$ 5.14
Forfeited	(1,245) ⁽¹⁾	\$ 3.48	(3,782) ⁽²⁾	\$ 4.86
Unvested units at December 31	<u>12,992</u>	<u>\$ 2.42</u>	<u>8,202</u>	<u>\$ 3.41</u>

(1) Includes 400,056 units related to the reduction in workforce for the year ended December 31, 2019.

(2) Includes 2,766,610 units related to the reduction in workforce for the year ended December 31, 2018.

Liability-Classified Performance Units

In 2019 and 2018, the Company granted performance units that vest at the end of, or over, a three-year period and are payable in either cash or shares at the option of the Compensation Committee of the Company's Board of Directors. The Company has accounted for these as liability-classified awards, and accordingly changes in the fair market value of the instruments will be recorded to general and administrative expense and capitalized expense over the vesting period of the awards. The performance unit awards granted in 2018 include a performance condition based on cash flow per debt-adjusted share and two market conditions, one based on absolute TSR and the other on relative TSR as compared to a group of the Company's peers. The fair values of the two market conditions are calculated by Monte Carlo models on a quarterly basis. The performance unit awards granted in 2019 include a performance condition based on return on average capital employed and two market conditions, one based on absolute TSR and the other on relative TSR. The fair values of the two market conditions are calculated by Monte Carlo models on a quarterly basis.

(in millions)

	2019	2018
Liability-classified performance units – general and administrative expense	\$ 2	\$ 2
Liability-classified performance units – general and administrative expense capitalized	\$ 1	\$ —

The Company also recorded a reduction in the deferred tax assets of less than \$1 million related to liability-classified performance units for the year ended December 31, 2019, compared to a deferred tax asset of \$1 million for the year ended December 31, 2018. As of December 31, 2019, there was \$6 million of total unrecognized compensation cost related to liability-classified performance units. This cost is expected to be recognized over a weighted-average period of two years. The amount of unrecognized compensation cost for liability-classified awards will fluctuate over time as they are marked to market. The final value of the performance unit awards is contingent upon the Company's actual performance against the Performance Measures.

The following table summarizes liability-classified performance unit activity to be paid out in cash for the years ended December 31, 2019 and 2018 and provides information for unvested units as of December 31, 2019 and 2018:

	2019		2018	
	Number of Shares <i>(in thousands)</i>	Weighted Average Fair Value	Number of Shares <i>(in thousands)</i>	Weighted Average Fair Value
Unvested units at January 1	2,803	\$ 3.41	—	\$ —
Granted	2,757	\$ 4.34	3,200	\$ 3.70
Vested	(43)	\$ 2.42	—	\$ —
Forfeited	(375) ⁽¹⁾	\$ 3.12	(397) ⁽²⁾	\$ 4.55
Unvested units at December 31	<u>5,142</u>	<u>\$ 2.42</u>	<u>2,803</u>	<u>\$ 3.41</u>

(1) Includes 375,086 units related to the reduction in workforce for the year ended December 31, 2019.

(2) Includes 295,160 units related to the reduction in workforce for the year ended December 31, 2018.

(15) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and liquids. The Marketing segment generates revenue through the marketing of both Company and third-party produced natural gas and liquids volumes.

Prior to December 2018, the Marketing segment included the Company's natural gas gathering business in its Fayetteville Shale assets. With the closing of the Fayetteville Shale sale in December 2018, the Company's marketing business comprises substantially all of the Company's Marketing segment.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income (loss), interest expense, gain (loss) on derivatives, gain (loss) on early extinguishment of debt and other income (loss). The "Other" column includes items not related to the Company's reportable segments, including real estate and corporate items.

<i>(in millions)</i>	Exploration and Production	Marketing	Other	Total
2019				
Revenues from external customers	\$ 1,740	\$ 1,298	\$ —	\$ 3,038
Intersegment revenues	(37)	1,552	—	1,515
Depreciation, depletion and amortization expense	462	9	—	471
Impairments	13	3	—	16
Operating income (loss)	283 ⁽¹⁾	(13)	—	270
Interest expense ⁽²⁾	65	—	—	65
Gain on derivatives	274	—	—	274
Gain on early extinguishment of debt	—	—	8	8
Other income (loss), net	(9)	—	2	(7)
Benefit from income taxes ⁽²⁾	(411)	—	—	(411)
Assets	6,235 ⁽³⁾	314	168 ⁽⁴⁾	6,717
Capital investments ⁽⁵⁾	1,138	—	2	1,140
2018 ⁽⁶⁾				
Revenues from external customers	\$ 2,551	\$ 1,311	\$ —	\$ 3,862
Intersegment revenues	(26)	2,434	—	2,408
Depreciation, depletion and amortization expense	514	46	—	560
Impairments	15	155 ⁽⁸⁾	1	171
Operating income (loss)	794 ⁽⁷⁾	4 ⁽⁹⁾	(1)	797
Interest expense ⁽²⁾	124	—	—	124
Loss on derivatives	(118)	—	—	(118)
Loss on early extinguishment of debt	—	—	(17)	(17)
Other income (loss), net	2	(2)	—	—
Provision for income taxes ⁽²⁾	1	—	—	1
Assets	4,872 ⁽³⁾	539	386 ⁽⁴⁾	5,797
Capital investments ⁽⁵⁾	1,231	9	8	1,248
2017				
Revenues from external customers	\$ 2,105	\$ 1,098	\$ —	\$ 3,203
Intersegment revenues	(19)	2,100	—	2,081
Depreciation, depletion and amortization expense	440	64	—	504
Operating income (loss)	549	183	(1)	731
Interest expense ⁽²⁾	135	—	—	135
Gain on derivatives	421	1	—	422
Loss on early extinguishment of debt	—	—	(70)	(70)
Other income, net	4	1	—	5
Benefit from income taxes ⁽²⁾	(93)	—	—	(93)
Assets	5,109 ⁽³⁾	1,288	1,124 ⁽⁴⁾	7,521
Capital investments ⁽⁵⁾	1,248	32	13	1,293

- (1) Operating income for the E&P segment includes \$11 million of restructuring charges for the year ended December 31, 2019.
- (2) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as they are incurred at the corporate level.
- (3) E&P assets includes office, technology, water infrastructure, drilling rigs and other ancillary equipment not directly related to natural gas and oil properties. This also includes deferred tax assets which are an allocation of corporate amounts as they are incurred at the corporate level.
- (4) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At December 31, 2019, 2018 and 2017, other assets included approximately \$5 million, \$205 million and \$914 million, respectively, in cash and cash equivalents, \$30 million, \$89 million and \$89 million, respectively, in income taxes receivable, \$27 million, \$60 million and \$95 million, respectively, in property, plant and equipment, \$11 million, \$11 million and \$5 million, respectively, in unamortized debt expense, \$8 million, \$8 million and \$11 million, respectively, in prepayments and \$7 million, \$8 million and \$10 million, respectively, in a non-qualified retirement plan. Additionally, the December 31, 2019 asset balance includes \$80 million in right-of-use lease assets and the December 31, 2018 asset balance includes \$4 million of accounts receivable and \$1 million of current hedging assets.
- (5) Capital investments include an increase of \$34 million for 2019 and a decrease of \$53 million for 2018 related to the change in accrued expenditures between years. There was no impact to 2017.
- (6) Includes the impact of approximately eleven months of Fayetteville Shale-related E&P and midstream gathering operations which were divested in December 2018.
- (7) Operating income for the E&P segment includes \$37 million related to restructuring charges for the year ended December 31, 2018.

- (8) Marketing includes a \$10 million non-cash impairment related to certain non-core midstream gathering assets at December 31, 2018.
- (9) Operating income for the Marketing segment includes \$2 million related to restructuring charges for the year ended December 31, 2018.

Included in intersegment revenues of the Marketing segment are \$1.6 billion, \$2.3 billion and \$1.9 billion for 2019, 2018 and 2017, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments.

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

In April 2018, the Company entered into the 2018 credit facility. Pursuant to requirements under the indentures governing the Company's senior notes, each 100% owned subsidiary that became a guarantor of the 2018 credit facility also became a guarantor of each of the Company's senior notes (the "Guarantor Subsidiaries"). The Guarantor Subsidiaries also granted liens and security interests to support their guarantees under the 2018 credit facility but not of the senior notes. These guarantees are full and unconditional and joint and several among the Guarantor Subsidiaries. Certain of the Company's operating units which are accounted for on a consolidated basis do not guarantee the 2018 credit facility and senior notes ("Non-Guarantor Subsidiaries"). See Note 9 for additional information on the Company's 2018 revolving credit facility and senior notes. At the closing of the Fayetteville Shale sale in December 2018, its subsidiaries being sold were released from these guarantees. See Note 3 for additional information on the divestiture of the Company's Fayetteville Shale-related subsidiaries.

The following financial information reflects consolidating financial information of Southwestern Energy Company (the parent and issuer company), its Guarantor Subsidiaries on a combined basis and the Non-Guarantor Subsidiaries on a combined basis, prepared on the equity basis of accounting. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

<i>(in millions)</i>	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
Year ended December 31, 2019					
Operating Revenues:					
Gas sales	\$ —	\$ 1,241	\$ —	\$ —	\$ 1,241
Oil sales	—	223	—	—	223
NGL sales	—	274	—	—	274
Marketing	—	1,297	—	—	1,297
Other	—	3	—	—	3
	<u>—</u>	<u>3,038</u>	<u>—</u>	<u>—</u>	<u>3,038</u>
Operating Costs and Expenses:					
Marketing purchases	—	1,320	—	—	1,320
Operating expenses	—	720	1	(1)	720
General and administrative expenses	—	166	—	—	166
Restructuring charges	—	11	—	—	11
Depreciation, depletion and amortization	—	470	1	—	471
Impairments	—	16	—	—	16
Loss on sale of assets, net	—	2	—	—	2
Taxes, other than income taxes	—	62	—	—	62
	<u>—</u>	<u>2,767</u>	<u>2</u>	<u>(1)</u>	<u>2,768</u>
	<u>—</u>	<u>271</u>	<u>(2)</u>	<u>1</u>	<u>270</u>
Operating Income (Loss)					
Interest Expense, Net	65	—	—	—	65
Gain on Derivatives	—	274	—	—	274
Gain on Early Extinguishment of Debt	8	—	—	—	8
Other Loss, Net	—	(7)	—	—	(7)
Equity in Earnings of Subsidiaries	947	(2)	—	(945)	—
	<u>890</u>	<u>536</u>	<u>(2)</u>	<u>(944)</u>	<u>480</u>
Income (Loss) Before Income Taxes	890	536	(2)	(944)	480
Benefit from Income Taxes	—	(411)	—	—	(411)
Net Income (Loss)	<u>\$ 890</u>	<u>\$ 947</u>	<u>\$ (2)</u>	<u>\$ (944)</u>	<u>\$ 891</u>
Net Income (Loss)	\$ 890	\$ 947	\$ (2)	\$ (944)	\$ 891
Other comprehensive income	3	—	—	—	3
Comprehensive Income (Loss)	<u>\$ 893</u>	<u>\$ 947</u>	<u>\$ (2)</u>	<u>\$ (944)</u>	<u>\$ 894</u>

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

<i>(in millions)</i>	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Year ended December 31, 2018					
Operating Revenues:					
Gas sales	\$ —	\$ 1,998	\$ —	\$ —	\$ 1,998
Oil sales	—	196	—	—	196
NGL sales	—	352	—	—	352
Marketing	—	1,222	—	—	1,222
Gas gathering	—	89	—	—	89
Other	—	5	—	—	5
	<u>—</u>	<u>3,862</u>	<u>—</u>	<u>—</u>	<u>3,862</u>
Operating Costs and Expenses:					
Marketing purchases	—	1,229	—	—	1,229
Operating expenses	—	785	—	—	785
General and administrative expenses	—	209	—	—	209
Restructuring charges	—	39	—	—	39
Depreciation, depletion and amortization	—	560	—	—	560
Impairments	—	171	—	—	171
Gain on sale of assets, net	—	(17)	—	—	(17)
Taxes, other than income taxes	—	89	—	—	89
	<u>—</u>	<u>3,065</u>	<u>—</u>	<u>—</u>	<u>3,065</u>
Operating Income	<u>—</u>	<u>797</u>	<u>—</u>	<u>—</u>	<u>797</u>
Interest Expense, Net	124	—	—	—	124
Loss on Derivatives	—	(118)	—	—	(118)
Loss on Early Extinguishment of Debt	(17)	—	—	—	(17)
Equity in Earnings of Subsidiaries	678	—	—	(678)	—
	<u>537</u>	<u>679</u>	<u>—</u>	<u>(678)</u>	<u>538</u>
Income (Loss) Before Income Taxes	537	679	—	(678)	538
Provision for Income Taxes	—	1	—	—	1
Net Income (Loss)	<u>\$ 537</u>	<u>\$ 678</u>	<u>\$ —</u>	<u>\$ (678)</u>	<u>\$ 537</u>
Participating securities – mandatorv convertible preferred stock	2	—	—	—	2
Net Income (Loss) Attributable to Common Stock	<u>\$ 535</u>	<u>\$ 678</u>	<u>\$ —</u>	<u>\$ (678)</u>	<u>\$ 535</u>
Net Income (Loss)	\$ 537	\$ 678	\$ —	\$ (678)	\$ 537
Other comprehensive income	8	—	—	—	8
Comprehensive Income (Loss)	<u>\$ 545</u>	<u>\$ 678</u>	<u>\$ —</u>	<u>\$ (678)</u>	<u>\$ 545</u>

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

<i>(in millions)</i>	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Year ended December 31, 2017					
Operating Revenues:					
Gas sales	\$ —	\$ 1,793	\$ —	\$ —	\$ 1,793
Oil sales	—	102	—	—	102
NGL sales	—	206	—	—	206
Marketing	—	972	—	—	972
Gas gathering	—	126	—	—	126
Other	—	4	—	—	4
	<u>—</u>	<u>3,203</u>	<u>—</u>	<u>—</u>	<u>3,203</u>
Operating Costs and Expenses:					
Marketing purchases	—	976	—	—	976
Operating expenses	—	671	—	—	671
General and administrative expenses	—	233	—	—	233
Depreciation, depletion and amortization	—	504	—	—	504
Gain on sale of assets, net	—	(6)	—	—	(6)
Taxes, other than income taxes	—	94	—	—	94
	<u>—</u>	<u>2,472</u>	<u>—</u>	<u>—</u>	<u>2,472</u>
Operating Income	<u>—</u>	<u>731</u>	<u>—</u>	<u>—</u>	<u>731</u>
Interest Expense, Net	135	—	—	—	135
Gain on Derivatives	—	422	—	—	422
Loss on Early Extinguishment of Debt	(70)	—	—	—	(70)
Other Income, Net	—	5	—	—	5
Equity in Earnings of Subsidiaries	1,251	—	—	(1,251)	—
	<u>1,046</u>	<u>1,158</u>	<u>—</u>	<u>(1,251)</u>	<u>953</u>
Income (Loss) Before Income Taxes	1,046	1,158	—	(1,251)	953
Benefit from Income Taxes	—	(93)	—	—	(93)
Net Income (Loss)	<u>\$ 1,046</u>	<u>\$ 1,251</u>	<u>\$ —</u>	<u>\$ (1,251)</u>	<u>\$ 1,046</u>
Mandatory convertible preferred stock dividend	108	—	—	—	108
Participating securities – mandatory convertible preferred stock	123	—	—	—	123
Net Income (Loss) Attributable to Common Stock	<u>\$ 815</u>	<u>\$ 1,251</u>	<u>\$ —</u>	<u>\$ (1,251)</u>	<u>\$ 815</u>
Net Income (Loss)	\$ 1,046	\$ 1,251	\$ —	\$ (1,251)	\$ 1,046
Other comprehensive income (loss)	(5)	6	6	(12)	(5)
Comprehensive Income (Loss)	<u>\$ 1,041</u>	<u>\$ 1,257</u>	<u>\$ 6</u>	<u>\$ (1,263)</u>	<u>\$ 1,041</u>

CONDENSED CONSOLIDATED BALANCE SHEETS

<i>(in millions)</i>	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
<u>December 31, 2019</u>					
ASSETS					
Cash and cash equivalents	\$ 5	\$ —	\$ —	\$ —	\$ 5
Accounts receivable, net	—	345	—	—	345
Other current assets	7	322	—	—	329
Total current assets	<u>12</u>	<u>667</u>	<u>—</u>	<u>—</u>	<u>679</u>
Intercompany receivables	7,922	—	—	(7,922)	—
Natural gas and oil properties, using the full cost method	—	25,195	55	—	25,250
Other	169	322	29	—	520
Less: Accumulated depreciation, depletion and amortization	(144)	(20,300)	(59)	—	(20,503)
Total property and equipment, net	<u>25</u>	<u>5,217</u>	<u>25</u>	<u>—</u>	<u>5,267</u>
Investments in subsidiaries (equity method)	—	23	—	(23)	—
Operating lease assets	80	79	—	—	159
Deferred tax assets	—	407	—	—	407
Other long-term assets	19	186	—	—	205
TOTAL ASSETS	<u><u>\$ 8,058</u></u>	<u><u>\$ 6,579</u></u>	<u><u>\$ 25</u></u>	<u><u>\$ (7,945)</u></u>	<u><u>\$ 6,717</u></u>
LIABILITIES AND EQUITY					
Accounts payable	\$ 79	\$ 446	\$ —	\$ —	\$ 525
Current operating lease liabilities	8	26	—	—	34
Other current liabilities	108	181	—	—	289
Total current liabilities	<u>195</u>	<u>653</u>	<u>—</u>	<u>—</u>	<u>848</u>
Intercompany payables	—	7,920	2	(7,922)	—
Long-term debt	2,242	—	—	—	2,242
Long-term operating lease liabilities	66	53	—	—	119
Pension and other postretirement liabilities	43	—	—	—	43
Other long-term liabilities	11	208	—	—	219
Negative carrying amount of subsidiaries, net	2,255	—	—	(2,255)	—
Total long-term liabilities	<u>4,617</u>	<u>261</u>	<u>—</u>	<u>(2,255)</u>	<u>2,623</u>
Commitments and contingencies					
Total equity (accumulated deficit)	<u>3,246</u>	<u>(2,255)</u>	<u>23</u>	<u>2,232</u>	<u>3,246</u>
TOTAL LIABILITIES AND EQUITY	<u><u>\$ 8,058</u></u>	<u><u>\$ 6,579</u></u>	<u><u>\$ 25</u></u>	<u><u>\$ (7,945)</u></u>	<u><u>\$ 6,717</u></u>

CONDENSED CONSOLIDATED BALANCE SHEETS

<i>(in millions)</i>	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
<u>December 31, 2018</u>					
ASSETS					
Cash and cash equivalents	\$ 201	\$ —	\$ —	\$ —	\$ 201
Accounts receivable, net	4	577	—	—	581
Other current assets	8	166	—	—	174
Total current assets	<u>213</u>	<u>743</u>	<u>—</u>	<u>—</u>	<u>956</u>
Intercompany receivables	7,932	—	—	(7,932)	—
Natural gas and oil properties, using the full cost method	—	24,128	52	—	24,180
Other	197	301	27	—	525
Less: Accumulated depreciation, depletion and amortization	(154)	(19,840)	(55)	—	(20,049)
Total property and equipment, net	<u>43</u>	<u>4,589</u>	<u>24</u>	<u>—</u>	<u>4,656</u>
Investments in subsidiaries (equity method)	—	24	—	(24)	—
Other long-term assets	19	166	—	—	185
TOTAL ASSETS	<u><u>\$ 8,207</u></u>	<u><u>\$ 5,522</u></u>	<u><u>\$ 24</u></u>	<u><u>\$ (7,956)</u></u>	<u><u>\$ 5,797</u></u>
LIABILITIES AND EQUITY					
Accounts payable	\$ 113	\$ 496	\$ —	\$ —	\$ 609
Other current liabilities	115	122	—	—	237
Total current liabilities	<u>228</u>	<u>618</u>	<u>—</u>	<u>—</u>	<u>846</u>
Intercompany payables	—	7,932	—	(7,932)	—
Long-term debt	2,318	—	—	—	2,318
Pension and other postretirement liabilities	46	—	—	—	46
Other long-term liabilities	54	171	—	—	225
Negative carrying amount of subsidiaries, net	3,199	—	—	(3,199)	—
Total long-term liabilities	<u>5,617</u>	<u>171</u>	<u>—</u>	<u>(3,199)</u>	<u>2,589</u>
Commitments and contingencies					
Total equity (accumulated deficit)	<u>2,362</u>	<u>(3,199)</u>	<u>24</u>	<u>3,175</u>	<u>2,362</u>
TOTAL LIABILITIES AND EQUITY	<u><u>\$ 8,207</u></u>	<u><u>\$ 5,522</u></u>	<u><u>\$ 24</u></u>	<u><u>\$ (7,956)</u></u>	<u><u>\$ 5,797</u></u>

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

<i>(in millions)</i>	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
<u>Year ended December 31, 2019</u>					
Net cash provided by (used in) operating activities	<u>\$ 1,280</u>	<u>\$ 629</u>	<u>\$ —</u>	<u>\$ (945)</u>	<u>\$ 964</u>
Investing activities:					
Capital investments	(4)	(1,093)	(2)	—	(1,099)
Proceeds from the sale of property and equipment	—	54	—	—	54
Net cash used in investing activities	<u>(4)</u>	<u>(1,039)</u>	<u>(2)</u>	<u>—</u>	<u>(1,045)</u>
Financing activities					
Intercompany activities	(1,357)	410	2	945	—
Payments on current portion of long-term debt	(52)	—	—	—	(52)
Payments on long-term debt	(54)	—	—	—	(54)
Payments on revolving credit facility	(532)	—	—	—	(532)
Borrowings under revolving credit facility	566	—	—	—	566
Change in bank drafts outstanding	(19)	—	—	—	(19)
Debt issuance costs	(3)	—	—	—	(3)
Purchase of treasury stock	(21)	—	—	—	(21)
Cash paid for tax withholding	(1)	—	—	—	(1)
Other	1	—	—	—	1
Net cash provided by (used in) financing activities	<u>(1,472)</u>	<u>410</u>	<u>2</u>	<u>945</u>	<u>(115)</u>
Decrease in cash and cash equivalents	(196)	—	—	—	(196)
Cash and cash equivalents at beginning of year	201	—	—	—	201
Cash and cash equivalents at end of year	<u>\$ 5</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 5</u>
<u>Year ended December 31, 2018</u>					
Net cash provided by (used in) operating activities	\$ 304	\$ 1,595	\$ —	\$ (676)	\$ 1,223
Investing activities:					
Capital investments	(20)	(1,270)	—	—	(1,290)
Proceeds from the sale of property and equipment	—	1,643	—	—	1,643
Other	—	6	—	—	6
Net cash used in investing activities	<u>(20)</u>	<u>379</u>	<u>—</u>	<u>—</u>	<u>359</u>
Financing activities					
Intercompany activities	1,300	(1,976)	—	676	—
Payments on long-term debt	(2,095)	—	—	—	(2,095)
Payments on revolving credit facility	(1,983)	—	—	—	(1,983)
Borrowings under revolving credit facility	1,983	—	—	—	1,983
Change in bank drafts outstanding	17	—	—	—	17
Debt issuance costs	(9)	—	—	—	(9)
Purchase of treasury stock	(180)	—	—	—	(180)
Preferred stock dividend	(27)	—	—	—	(27)
Cash paid for tax withholding	(3)	—	—	—	(3)
Net cash provided by (used in) financing activities	<u>(997)</u>	<u>(1,976)</u>	<u>—</u>	<u>676</u>	<u>(2,297)</u>
Decrease in cash and cash equivalents	(713)	(2)	—	—	(715)
Cash and cash equivalents at beginning of year	914	2	—	—	916
Cash and cash equivalents at end of year	<u>\$ 201</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 201</u>

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

<i>(in millions)</i>	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
Year ended December 31, 2017					
Net cash provided by (used in) operating activities	\$ 1,019	\$ 1,327	\$ —	\$ (1,249)	\$ 1,097
Investing activities:					
Capital investments	(13)	(1,250)	(5)	—	(1,268)
Proceeds from the sale of property and equipment	1	9	—	—	10
Other	1	5	—	—	6
Net cash used in investing activities	(11)	(1,236)	(5)	—	(1,252)
Financing activities:					
Intercompany activities	(1,158)	(96)	5	1,249	—
Payments on short-term debt	(328)	—	—	—	(328)
Payments on long-term debt	(1,139)	—	—	—	(1,139)
Proceeds from issuance of long-term debt	1,150	—	—	—	1,150
Change in bank drafts outstanding	9	—	—	—	9
Debt issuance costs	(24)	—	—	—	(24)
Cash paid for tax withholding	(2)	—	—	—	(2)
Preferred stock dividend	(16)	—	—	—	(16)
Other	(2)	—	—	—	(2)
Net cash provided by (used in) financing activities	(1,510)	(96)	5	1,249	(352)
Decrease in cash and cash equivalents	(502)	(5)	—	—	(507)
Cash and cash equivalents at beginning of year	1,416	7	—	—	1,423
Cash and cash equivalents at end of year	\$ 914	\$ 2	\$ —	\$ —	\$ 916

(17) SUBSEQUENT EVENTS

On February 4, 2020, the Company notified employees of a workforce reduction plan as a result of a strategic realignment of its organizational structure. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of their unvested long-term incentive awards that were forfeited. The plan is expected to be substantially implemented by the end of the first quarter of 2020. The Company expects to record a pre-tax charge to earnings of approximately \$9 million in the first quarter of 2020 related to the severance payments.

SUPPLEMENTAL QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2019 and 2018:

<i>(in millions, except share amounts)</i>	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	2019			
Operating revenues	\$ 990	\$ 667	\$ 636	\$ 745
Operating income (loss)	213	22	(29)	64
Net income attributable to common stock	594	138	49	110
Earnings per share – Basic	1.10	0.26	0.09	0.20
Earnings per share – Diluted	1.10	0.26	0.09	0.20
	2018			
Operating revenues	\$ 920	\$ 816	\$ 951	\$ 1,175
Operating income	255	124	66	352
Net income (loss) attributable to common stock	205	51	(29)	307
Earnings (loss) per share – Basic	0.36	0.09	(0.05)	0.54
Earnings (loss) per share – Diluted	0.36	0.09	(0.05)	0.54

SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

The Company's operating natural gas and oil properties are located solely in the United States. The Company also has licenses to properties in Canada, the development of which is subject to an indefinite moratorium. See "Our Operations – Other – New Brunswick, Canada" in Item 1 of Part 1 of this Annual Report.

Net Capitalized Costs

The following table shows the capitalized costs of natural gas and oil properties and the related accumulated depreciation, depletion and amortization as of December 31, 2019 and 2018:

<i>(in millions)</i>	2019	2018
Proved properties	\$ 23,744	\$ 22,425
Unproved properties	1,506	1,755
Total capitalized costs	25,250	24,180
Less: Accumulated depreciation, depletion and amortization	(20,203)	(19,761)
Net capitalized costs	\$ 5,047	\$ 4,419

Natural gas and oil properties not subject to amortization represent investments in unproved properties and major development projects in which the Company owns an interest. These unproved property costs include unevaluated costs associated with leasehold or drilling interests and unevaluated costs associated with wells in progress. The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2019:

<i>(in millions)</i>	2019	2018	2017	Prior	Total
Property acquisition costs	\$ 45	\$ 40	\$ 32	\$ 1,106	\$ 1,223
Exploration and development costs	53	23	16	12	104
Capitalized interest	67	47	27	38	179
	\$ 165	\$ 110	\$ 75	\$ 1,156	\$ 1,506

Of the total net unevaluated costs excluded from amortization as of December 31, 2019, approximately \$1.2 billion is related to undeveloped properties in Southwest Appalachia (acquired in 2014 and 2015) and approximately \$10 million is related to the acquisition of undeveloped properties in Northeast Appalachia. Additionally, the Company has approximately \$179 million of unevaluated capitalized interest and \$95 million of unevaluated costs related to wells in progress. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The timing and amount of property acquisition and seismic costs included in the amortization computation will depend on the location and timing of drilling wells, results of drilling and other assessments. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

Costs Incurred in Natural Gas and Oil Exploration and Development

The table below sets forth capitalized costs incurred in natural gas and oil property acquisition, exploration and development activities:

<i>(in millions, except per Mcfe amounts)</i>	2019	2018	2017
Unproved property acquisition costs	\$ 162	\$ 164	\$ 194
Exploration costs	2	5	22
Development costs	936	1,014	1,024
Capitalized costs incurred	\$ 1,100	\$ 1,183	\$ 1,240
Full cost nool amortization per Mcfe	\$ 0.56	\$ 0.51	\$ 0.45

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized \$109 million, \$115 million and \$113 million during 2019, 2018 and 2017, respectively, based on the Company's weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling \$77 million, \$90 million and \$99 million during 2019, 2018 and 2017, respectively, which were directly related to the acquisition, exploration and development of the Company's natural gas and oil properties.

Results of Operations from Natural Gas and Oil Producing Activities

The table below sets forth the results of operations from natural gas and oil producing activities:

<i>(in millions)</i>	<u>2019</u>	<u>2018</u>	<u>2017</u>
Sales	\$ 1,703	\$ 2,525	\$ 2,086
Production (lifting) costs	(781)	(974)	(891)
Depreciation, depletion and amortization	(462)	(514)	(440)
	<u>460</u>	<u>1,037</u>	<u>755</u>
Provision for income taxes ⁽¹⁾	110	—	—
Results of operations ⁽²⁾	<u>\$ 350</u>	<u>\$ 1,037</u>	<u>\$ 755</u>

- (1) Prior to the recognition of a valuation allowance, in 2018 and 2017 the Company recognized income tax provisions of \$254 million and \$287 million, respectively.
- (2) Results of operations exclude the gain (loss) on unsettled commodity derivative instruments. See Note 6.

The results of operations shown above exclude general and administrative expenses and interest expense and are not necessarily indicative of the contribution made by the Company's natural gas and oil operations to its consolidated operating results. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

Natural Gas and Oil Reserve Quantities

The Company engaged the services of Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm, to audit the reserves estimated by the Company's reservoir engineers. In conducting its audit, the engineers and geologists of NSAI studied the Company's major properties in detail and independently developed reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of the Company's major properties, and accounted for approximately 99% of the present worth of the Company's total proved reserves as of December 31 of 2019, 2018 and 2017. A reserve audit is not the same as a financial audit, and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimate of reserves. Reserve estimates are inherently imprecise, and the Company's reserve estimates are generally based upon extrapolation of historical production trends, historical prices of natural gas and crude oil and analogy to similar properties and volumetric calculations. Accordingly, the Company's estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available. For more information over reserves, refer to the table titled "Changes in Proved Undeveloped Reserves (Bcfe)" in "Business – Exploration and Production" in Item 1 of this Annual Report.

The following table summarizes the changes in the Company's proved natural gas, oil and NGL reserves for 2019, 2018 and 2017, all of which were located in the United States:

	Natural Gas (Bcf)	Oil (MBbls)	NGL (MBbls)	Total (Bcfe)
December 31, 2016	4,866	10,523	53,931	5,253
Revisions of previous estimates due to price	1,327	3,197	57,447	1,691
Revisions of previous estimates other than price	571	(1,529)	13,102	641
Extensions, discoveries and other additions ⁽¹⁾	5,159	55,772	432,220	8,087
Production	(797)	(2,327)	(14,245)	(897)
Acquisition of reserves in place	—	—	—	—
Disposition of reserves in place	—	—	—	—
December 31, 2017	11,126	65,636	542,455	14,775
Revisions of previous estimates due to price	96	788	8,912	154
Revisions of previous estimates other than price	316	410	8,855	372
Extensions, discoveries and other additions	753	5,830	36,823	1,009
Production	(807)	(3,407)	(19,706)	(946)
Acquisition of reserves in place	—	—	—	—
Disposition of reserves in place ⁽²⁾	(3,440)	(250)	(276)	(3,443)
December 31, 2018	8,044	69,007	577,063	11,921
Revisions of previous estimates due to price	(480)	(2,041)	(37,492)	(717)
Revisions of previous estimates other than price ⁽³⁾	685	3,707	65,869	1,102
Extensions, discoveries and other additions	992	6,948	26,941	1,195
Production	(609)	(4,696)	(23,620)	(778)
Acquisition of reserves in place	—	—	—	—
Disposition of reserves in place	(2)	—	—	(2)
December 31, 2019	8,630	72,925	608,761	12,721

(1) The 2017 PUD additions are primarily associated with the increase in commodity prices.

(2) The 2018 disposition is primarily associated with the Fayetteville Shale sale.

(3) Revisions of previous estimates other than price includes 109 Bcfe of proved undeveloped reserves reclassified to unproved due to changes in the drilling plan, in accordance with the SEC five-year rule.

	Natural Gas (Bcf)	Oil (MBbls)	NGL (MBbls)	Total (Bcfe)
Proved developed reserves as of:				
December 31, 2017	6,979	14,513	142,213	7,920
December 31, 2018	4,395	18,037	175,480	5,557
December 31, 2019	4,906	26,124	226,271	6,421
Proved undeveloped reserves as of:				
December 31, 2017	4,147	51,123	400,242	6,855
December 31, 2018	3,649	50,970	401,583	6,364
December 31, 2019	3,724	46,801	382,490	6,300

The Company's estimated proved natural gas, oil and NGL reserves were 12,721 Bcfe at December 31, 2019, compared to 11,921 Bcfe at December 31, 2018. The Company's reserves increased in 2019, compared to 2018, as positive extensions, discoveries, other additions and non-price revisions in Appalachia were only partially offset by negative price revisions. The decrease in the Company's reserves in 2018 primarily resulted from the disposition of the reserves related to the Fayetteville Shale and was only partially offset by positive extensions, discoveries, other additions and revisions in Appalachia. The increase in the Company's reserves in 2017 was primarily due to extensions, discoveries and other additions in Appalachia along with increases in both price and performance revisions across the portfolio.

The following table summarizes the changes in reserves for 2017, 2018 and 2019:

<i>(in Bcfe)</i>	Appalachia		Fayetteville		Total
	Northeast	Southwest	Shale ⁽¹⁾	Other ⁽²⁾	
December 31, 2016	1,574	677	2,997	5	5,253
Net revisions					
Price revisions	903	738	49	1	1,691
Performance and production revisions	154	125	358	4	641
Total net revisions	1,057	863	407	5	2,332
Extensions, discoveries and other additions					
Proved developed	790	419	48	1	1,258
Proved undeveloped	1,100	5,186	543	—	6,829
Total reserve additions	1,890	5,605	591	1	8,087
Production	(395)	(183)	(316)	(3)	(897)
Acquisition of reserves in place	—	—	—	—	—
Disposition of reserves in place	—	—	—	—	—
December 31, 2017	4,126	6,962	3,679	8	14,775
Net revisions					
Price revisions	41	106	6	1	154
Performance and production revisions	107	272	(6)	(1)	372
Total net revisions	148	378	—	—	526
Extensions, discoveries and other additions					
Proved developed	154	22	1	—	177
Proved undeveloped	397	435	—	—	832
Total reserve additions	551	457	1	—	1,009
Production	(459)	(243)	(243)	(1)	(946)
Acquisition of reserves in place	—	—	—	—	—
Disposition of reserves in place	—	—	(3,437)	(6)	(3,443)
December 31, 2018	4,366	7,554	—	1	11,921
Net revisions					
Price revisions	(57)	(660)	—	—	(717)
Performance and production revisions ⁽³⁾	127	975	—	—	1,102
Total net revisions	70	315	—	—	385
Extensions, discoveries and other additions					
Proved developed	185	6	—	—	191
Proved undeveloped	677	327	—	—	1,004
Total reserve additions	862	333	—	—	1,195
Production	(459)	(319)	—	—	(778)
Acquisition of reserves in place	—	—	—	—	—
Disposition of reserves in place	(2)	—	—	—	(2)
December 31, 2019	4,837	7,883	—	1	12,721

(1) The Fayetteville Shale E&P assets and associated reserves were divested in December 2018.

(2) Other includes properties outside of Appalachia and Fayetteville Shale.

(3) Performance and production revisions includes 109 Bcfe of proved undeveloped reserves reclassified to unproved due to changes in the drilling plan, in accordance with the SEC five-year rule.

The Company's December 31, 2019 proved reserves included 929 Bcfe of proved undeveloped reserves from 90 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties had a negative present value of \$50 million when discounted at 10%. The Company made a final investment decision and is committed to developing these reserves within the next five years from the date of initial booking.

The Company's December 31, 2018 proved reserves included 190 Bcfe of proved undeveloped reserves from 30 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative \$24 million present value when discounted at 10%. The Company's December 31, 2017 proved reserves included 1,375

Bcfe of proved undeveloped reserves from 330 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative \$124 million present value when discounted at 10%.

The Company has no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. The Company used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis, offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

Standardized Measure of Discounted Future Net Cash Flows

The following standardized measures of discounted future net cash flows relating to proved natural gas, oil and NGL reserves as of December 31, 2019, 2018 and 2017 are calculated after income taxes, discounted using a 10% annual discount rate and do not purport to present the fair market value of the Company's proved gas, oil and NGL reserves:

<i>(in millions)</i>	<u>2019</u>	<u>2018</u>	<u>2017</u>
Future cash inflows	\$ 27,003	\$ 34,523	\$ 36,576
Future production costs	(14,981)	(15,347)	(18,390)
Future development costs ⁽¹⁾	(3,246)	(4,095)	(4,676)
Future income tax expense	(476)	(2,079)	(1,342)
Future net cash flows	<u>8,300</u>	<u>13,002</u>	<u>12,168</u>
10% annual discount for estimated timing of cash flows	(4,600)	(7,003)	(6,606)
Standardized measure of discounted future net cash flows	<u>\$ 3,700</u>	<u>\$ 5,999</u>	<u>\$ 5,562</u>

(1) Includes abandonment costs.

Under the standardized measure, future cash inflows were estimated by applying an average price from the first day of each month from the previous 12 months, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Prices used for the standardized measure above were as follows:

<i>(in millions)</i>	<u>2019</u>	<u>2018</u>	<u>2017</u>
Natural gas <i>(per MMBtu)</i>	\$ 2.58	\$ 3.10	\$ 2.98
Oil <i>(per Bbl)</i>	55.69	65.56	47.79
NGLs <i>(per Bbl)</i>	11.58	17.64	14.41

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the year-end statutory rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved gas and oil properties after giving effect to permanent differences and tax credits.

Following is an analysis of changes in the standardized measure during 2019, 2018 and 2017:

<i>(in millions)</i>	<u>2019</u>	<u>2018</u>	<u>2017</u>
Standardized measure, beginning of year	\$ 5,999	\$ 5,562	\$ 1,665
Sales and transfers of natural gas and oil produced, net of production costs	(923)	(1,564)	(1,191)
Net changes in prices and production costs	(3,510)	2,162	1,963
Extensions, discoveries, and other additions, net of future production and development costs	234	335	1,715
Acquisition of reserves in place	—	—	—
Sales of reserves in place	(2)	(2,022)	—
Revisions of previous quantity estimates	152	361	1,721
Net change in income taxes	491	(304)	(222)
Changes in estimated future development costs	621	(166)	(6)
Previously estimated development costs incurred during the year	704	536	55
Changes in production rates (timing) and other	(718)	521	(304)
Accretion of discount	652	578	166
Standardized measure, end of year	<u>\$ 3,700</u>	<u>\$ 5,999</u>	<u>\$ 5,562</u>

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of December 31, 2019 at a reasonable assurance level.

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2019, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 72 of this Annual Report.

PricewaterhouseCoopers LLP's report on Southwestern Energy's internal control over financial reporting is included in its Report of Independent Registered Public Accounting Firm on page 72 of this Annual Report.

ITEM 9B. OTHER INFORMATION

On February 24, 2020, the Compensation Committee of the Board of Directors of Southwestern Energy Company granted, subject to the approval of the Board, long-term incentives under the Company's 2013 Incentive Plan, as amended (the "Plan"), to its principal executive officer, principal financial officer and other named executive officers. On February 25, 2020, the Company's Board approved these grants.

The grants were comprised of two types of awards, the principal features of which are:

Restricted Stock Units. Each restricted stock unit that vests will entitle the holder to receive, payable in common stock or cash at the Compensation Committee's option, a value based on an adjusted stock price, calculated as the sum of (1) the closing stock price on the date of grant and (2) 50% of the difference between (a) the closing stock price on the date of vesting and (b) the closing stock price on the date of grant. If paid in stock, in no event will the number of shares of common stock delivered to the Participant exceed the number of restricted stock units granted to the participant. 25% of the restricted stock units vest on each of the first through the fourth anniversaries of the date of grant, provided the grantee is still an employee of the Company on the vesting date; however, all restricted stock units vest in the case of the grantee's Retirement, death or Disability or on a Change in Control, all as defined in the Plan.

Performance Units. Each performance unit that vests will entitle the holder to receive a value, payable in cash, based on the Company's performance regarding specified metrics and on an adjusted stock price, as calculated above. The vesting date is the third anniversary of the date of grant, provided the grantee is still an employee of the Company on the vesting date; however, a pro rata portion of performance units vest in the case of the grantee's Retirement, death or Disability, as defined in the Plan. Upon a Change in Control, as defined in the Plan, the performance period is deemed to end upon the change of control, and each unit granted vests at the greater of the adjusted stock price and the payment value based on the results of the performance measures. The determination of the value of each unit, 0-200%, is based on the achievement of threshold, target or maximum goals on the following metrics over a three-year performance period, being the calendar years 2020-2022:

- 50% Relative Total Shareholder Return – the difference between (a) the average of the closing prices for the Company's common stock on the last 20 trading days of 2022 plus all dividends paid on account of one share of the Company's common stock and (b) the average of the closing prices for the last 20 trading days of 2019, as compared to the same calculation for a specified group of the Company's peers.

- 50% Return on Average Capital Employed – calculated by dividing (i) the average of net cash provided by operating activities from the Consolidated Statement of Cash Flows less “changes in assets and liabilities” included in the Operating Activities section of the Consolidated Statement of Cash Flows for the performance period by the sum of (ii) the product of the twenty-day average stock price immediately prior to the first day of the performance period and the diluted weighted average number of shares of common stock of the Company outstanding for the fourth quarter of the year prior to the beginning of the performance period, (iii) gross debt of the Company (net of cash and cash equivalents) outstanding on December 31 of the year prior to the beginning of the performance period, and (iv) the sum of (a) the product of the number of shares of common stock the Company issued during the performance period and the price of said shares and (b) the amount of additional net debt incurred during the performance period, which sum shall then be reduced by (c) the amount by which any net debt is reduced during the performance period and (d) the product of the number of shares of common stock of the company purchased by the company during the performance period and the price of said shares, with each occurrence of the above in (a) – (d) multiplied by a fraction in which the denominator equals the total number of quarters in the Performance Period (12) and the numerator equals the remaining number of quarters following each occurrence of the above in (a) – (d) plus one.

Performance at target level for both metrics will result in a payout of 100%, and performance at maximum for both metrics entitles the holder to 200%. The Relative Total Shareholder Return portion will be deemed not to exceed the target level if absolute total shareholder return is negative.

William J. Way, President and Chief Executive Officer, was granted 1,863,500 of each type of award; Clay Carrell, Executive Vice President and Chief Operating Officer, was granted 883,440 of each type of award; Julian M. Bott, Executive Vice President and Chief Financial Officer, was granted 690,190 of each type of award; J. David Cecil, Executive Vice President, Corporate Development was granted 759,210 of each type of award; John C. Ale, Senior Vice President, General Counsel and Secretary, was granted 488,660 of each type of unit award.

There was no additional information required to be disclosed in a current report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2019, that was not reported on such form.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The definitive proxy statement to holders of the Company’s common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Stockholders to be held on or about May 19, 2020 (the “Proxy Statement”), is hereby incorporated by reference for the purpose of providing information about the Company’s directors, and for discussion of its audit committee and its audit committee financial expert. Refer to the sections “Proposal No. 1: Election of Directors” and “Share Ownership of Management, Directors and Nominees” in the Proxy Statement for information concerning our directors. Refer to the section “Corporate Governance – Committees of the Board of Directors” in the 2020 Proxy Statement for discussion of its audit committee and its audit committee financial expert. Information concerning the Company’s executive officers is presented in Part I of this Annual Report. The Company refers you to the section “Section 16(a) Beneficial Ownership Reporting Compliance” in the Proxy Statement for information relating to compliance with Section 16(a) of the Exchange Act.

Code of Business Ethics and Conduct for Directors and Employees

The Company has adopted Business Conduct Guidelines that apply to its Chief Executive Officer, Chief Financial Officer and Controller as well as other officers and employees. We have posted a copy of our Business Conduct Guidelines on the “Corporate Governance” section of our website at www.swn.com, and it is available free of charge in print to any stockholder who requests it. Requests for copies should be addressed to the Secretary at 10000 Energy Drive, Spring, Texas 77389. Any amendments to, or waivers from, our code of ethics that apply to our executive officers and directors will be posted on the “Corporate Governance” section of our website.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 19, 2020, and is incorporated herein by reference.*

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 19, 2020, and is incorporated herein by reference.*

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 19, 2020, and is incorporated herein by reference.*

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 19, 2020, and is incorporated herein by reference.*

* Except for information or data specifically incorporated by reference under Items 10 through 14, all other information in our 2020 Proxy Statement is not deemed to be a part of this Annual Report or deemed to be filed with the Commission as part of this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

- (a) (1) The consolidated financial statements of Southwestern Energy Company and its subsidiaries and the report of independent registered public accounting firm are included in Item 8 of this Annual Report.
- (2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.
- (3) The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Annual Report.

ITEM 16. 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 the report to be signed on its behalf by the undersigned, thereunto duly authorized.

Dated: February 27, 2020

SOUTHWESTERN ENERGY COMPANY

By: /s/ JULIAN M. BOTT

Julian M. Bott

Executive Vice President and
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 27, 2020, on behalf of the Registrant below by the following officers and by a majority of the directors.

/s/ WILLIAM J. WAY Director, President and Chief Executive Officer
William J. Way (Principal executive officer)

/s/ JULIAN M. BOTT Executive Vice President and Chief Financial Officer
Julian M. Bott (Principal financial officer)

/s/ COLIN P. O'BEIRNE Vice President, Controller
Colin P. O'Beirne (Principal accounting officer)

/s/ JOHN D. GASS Director
John D. Gass

/s/ CATHERINE KEHR Director
Catherine Kehr

/s/ GREG D. KERLEY Director
Greg D. Kerley

/s/ JON A. MARSHALL Director
Jon A. Marshall

/s/ PATRICK M. PREVOST Director
Patrick M. Prevost

/s/ ANNE TAYLOR Director
Anne Taylor

/s/ DENIS J. WALSH III Director
Denis J. Walsh III

EXHIBIT INDEX

Exhibit Number	Description
2.1	Membership Interest Purchase Agreement dated as of August 30, 2018 between Southwestern Energy Company and Flywheel Energy Operating, LLC (Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed on September 4, 2018)
2.2	Closing Agreement and First Amendment to Membership Interest Purchase Agreement dated as of December 3, 2018 between Southwestern Energy Company and Flywheel Energy Operating, LLC (Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed on December 4, 2018)
3.1	Amended and Restated Certificate of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed May 24, 2010)
3.2	Amended and Restated Bylaws of Southwestern Energy Company, as amended on April 25, 2017. (Incorporated by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017)
3.3	Certificate of Designations of 6.25% Series B Mandatory Convertible Preferred Stock (including form of stock certificate). (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on January 21, 2015)
3.4	Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock, dated April 9, 2009. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on April 9, 2009)
4.1*	Description of the Company's Securities Registered under Section 12 of the Securities Exchange Act of 1934
4.2	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.3	Policy on Confidential Voting of Southwestern Energy Company. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2006 Annual Meeting of Stockholders)
4.4	Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago, as trustee. (Incorporated by reference to Exhibit 4 to Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (File No. 33-63895) filed on November 17, 1995)
4.5	First Supplemental Indenture between Southwestern Energy Company and J.P. Morgan Trust Company, N.A. (as successor to the First National Bank of Chicago) dated June 30, 2006. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.6	Second Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee (as successor to J.P. Morgan Trust Company, N.A.), dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K/A filed on May 8, 2008)
4.7	Indenture dated June 1, 1998 by and among NOARK Pipeline Finance, L.L.C. and The Bank of New York. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed May 4, 2006)
4.8	First Supplemental Indenture dated May 2, 2006 by and among Southwestern Energy Company, NOARK Pipeline Finance, L.L.C., and UMB Bank, N.A., as trustee (as successor to the Bank of New York). (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed May 4, 2006)
4.9	Second Supplemental Indenture between Southwestern Energy Company and UMB Bank, N.A., as trustee, dated June 30, 2006. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.10	Third Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and UMB Bank, N.A., as trustee, dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed on May 8, 2008)
4.11	Guaranty dated June 1, 1998 by Southwestern Energy Company in favor of The Bank of New York, as trustee, under the Indenture dated as of June 1, 1998 between NOARK Pipeline Finance L.L.C. and such trustee. (Incorporated by reference to Exhibit 4.6 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2005)
4.12	Indenture dated January 16, 2008 among Southwestern Energy Company, the Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed January 16, 2008)

- 4.13 Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee, dated as of March 5, 2012. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed March 6, 2012)
- 4.14 First Supplemental Indenture, dated as of November 29, 2017 between Southwestern Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed December 1, 2017)
- 4.15 Second Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
- 4.16 Third Supplemental Indenture, dated as of September 17, 2018 between Southwestern Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 18, 2018)
- 4.17 Form of certificate for the 6.25% Series B Mandatory Convertible Preferred Stock. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on January 21, 2015)
- 4.18 Deposit Agreement, dated as of January 21, 2015, between Southwestern Energy Company and Computershare Trust Company, N.A., as depository, on behalf of all holders from time to time of the receipts issued thereunder (including form of Depositary Receipt). (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on January 21, 2015)
- 4.19 Form of Depositary Receipt for the Depositary Shares. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on January 21, 2015)
- 4.20 Indenture, dated as of January 23, 2015 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
- 4.21 Form of 3.300% Notes due 2018. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
- 4.22 Form of 4.050% Notes due 2020. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
- 4.23 Form of 4.95% Notes due 2025. (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
- 4.24 First Supplemental Indenture, dated as of January 23, 2015 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
- 4.25 Second Supplemental Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
- 4.26 Third Supplemental Indenture, dated as of November 29, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on December 1, 2017)
- 4.27 Fourth Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
- 4.28 Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
- 4.29 First Supplemental Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
- 4.30 Second Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
- 4.31 Form of 7.50% Notes due 2026. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
- 4.32 Form of 7.75% Notes due 2027. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
- 10.1 Form of Second Amended and Restated Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)

- 10.2 Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
- 10.3 Form of Amendment to Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company prior to 2011. (Incorporated by reference to Exhibit 10.3 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008)
- 10.4 Form of Executive Severance Agreement between Southwestern Energy Company and Executive Officers Post 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant's Annual Report on Form 10-K (Commission File No.1-08426) for the year ended December 31, 2011)
- 10.5 Southwestern Energy Company Supplemental Retirement Plan as amended. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
- 10.6 Southwestern Energy Company Non-Qualified Retirement Plan as amended. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
- 10.7 Amendment One to the Southwestern Energy Company Non-Qualified Retirement Plan (Incorporated by reference to Exhibit 10.9 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
- 10.8 Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Annex A of the Registrant's Proxy Statement filed April 8, 2013)
- 10.9 First Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 20, 2016)
- 10.10 Second Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 30, 2017)
- 10.11 Third Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 22, 2019)
- 10.12 Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement, for awards granted prior to February 25, 2020. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on March 8, 2018)
- 10.13* Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement
- 10.14 Southwestern Energy Company 2013 Incentive Plan Guidelines for Annual Incentive Awards. (Incorporated by reference to Exhibit 10.03 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
- 10.15 Southwestern Energy Company 2013 Incentive Plan Form of Incentive Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.04 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
- 10.16 Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.05 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
- 10.17 Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement for Directors. (Incorporated by reference to Exhibit 10.06 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
- 10.18 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement. (Incorporated by reference to Exhibit 10.07 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
- 10.19 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement for Directors, as amended on May 23, 2017. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
- 10.20 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 8, 2018)
- 10.21* Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Officers
- 10.22 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors, for awards granted prior to July 1, 2019. (Incorporated by reference to Exhibit 10.10 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
- 10.23 Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors, for awards granted on or after July 1, 2019. (Incorporated by reference to Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019)
- 10.24 Southwestern Energy Company Non-Employee Director Deferred Compensation Plan. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019)

- 10.25 Form of Deferral Agreement under the Non-Employee Director Deferred Compensation Plan. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019)
- 10.26 Form of Incentive Stock Option for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
- 10.27 Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2011. (Incorporated by reference to Exhibit 10.20 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08426) for the year ended December 31, 2011)
- 10.28 Guaranty by and between Southwestern Energy Company and Texas Gas Transmission, LLC, dated as of October 27, 2008. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q (Commission File No. 1-08246) for the period ended September 30, 2008)
- 10.29 Guaranty by and between Southwestern Energy Company and Fayetteville Express Pipeline, LLC dated September 30, 2008 (Incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
- 10.30 Separation and Release Agreement dated August 23, 2017 between Southwestern Energy Company and Mark K. Boling. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
- 10.31 Amendment to Awards Agreement dated August 23, 2017 between Southwestern Energy Company and Mark K. Boling. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
- 10.32 Retirement Agreement dated December 20, 2018 between Southwestern Energy Company and John E. "Jack" Bergeron, Jr. (Incorporated by reference to Exhibit 10.29 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2018)
- 10.33 Amendment to Awards Agreement dated December 20, 2018 between Southwestern Energy Company and John E. "Jack" Bergeron, Jr. (Incorporated by reference to Exhibit 10.30 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2018)
- 10.34 Credit Agreement, dated June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
- 10.35 Amendment No. 1 to Credit Agreement, dated as of June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
- 10.36 Amendment No. 1 to Credit Agreement, dated as of September 11, 2017 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as administrative agent, and each lender from time to time party thereto. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on September 11, 2017)
- 10.37 Amendment and Restatement Agreement, dated as of June 27, 2016 among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and the lenders party thereto, giving effect to the Amended and Restated Term Loan Credit Agreement. (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
- 10.38 Amended and Restated Term Loan Credit Agreement, dated June 27, 2016 among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit A to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
- 10.39 Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
- 10.40 Amendment No. 1 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed on October 25, 2018)
- 10.41 Amendment No. 2 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank N.A., as Administrative Agent, and each lender from time to time party thereto. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on October 9, 2019)
- 10.42* Amendment No. 3 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank N.A., as Administrative Agent, and each lender from time to time party thereto
- 10.43* Amendment No. 4 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank N.A., as Administrative Agent, and each lender from time to time party thereto
- 21.1* List of Subsidiaries
- 23.1* Consent of PricewaterhouseCoopers LLP
- 23.2* Consent of Netherland, Sewell & Associates, Inc.

- 31.1* Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
- 31.2* Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
- 32.1* Certification of CEO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
- 32.2* Certification of CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
- 95.1* Mine Safety Disclosure
- 99.1* Reserve Audit Report of Netherland, Sewell & Associates, Inc., dated February 7, 2020
- 101.1* Interactive Data Files Pursuant to Rule 405 of Regulation S-T, formatted in Inline XBRL: (i) Consolidated Statements of Operations for the three years ended December 31, 2019, (ii) Consolidated Statements of Comprehensive Income for the three years ended December 31, 2019, (iii) Consolidated Balance Sheets as of December 31, 2019 and 2018, (iv) Consolidated Statements of Cash Flows for the three years ended December 31, 2019, (v) Consolidated Statements of Changes in Equity for the three years ended December 31, 2019 and (vi) Notes to Consolidated Financial Statements
- 104.1* The cover page from the Company's Annual Report on Form 10-K for the year ended December 31, 2019, formatted in Inline XBRL (included in Exhibit 101)

* Filed herewith



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