SOUTHWESTERN ENERGY CO
Form 10-K
February 28, 2019

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

Form 10-K

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2018
Commission file number 001-08246

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:

Title of each class	Name of each exchange on which registered
Common Stock, Par Value $0.01	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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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 $3,096,452,639 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2018 of $5.30. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 26, 2019, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 541,319,293.

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 21, 2019 are incorporated by reference into Part III of this Form 10-K.

Table of Contents

Index to Financial Statements

SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2018

TABLE OF CONTENTS

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

ITEM 1. BUSINESS

Southwestern Energy Company (including its subsidiaries, collectively, "we", "our", "us", "the Company" or "Southwestern") 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 currently 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 assured 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:

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 over the next two years by a portion of the proceeds from our recent asset sales. 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.

Table of Contents

Index to Financial Statements

- 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 are investing in a water transportation project in West Virginia, a portion of which is already in service and providing approximately $0.5 million in savings per well. These activities provide operational flexibility, help protect our margin, lower our well costs, minimize the risk of unavailability of these resources from third parties and capture additional value.
- 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.

In recent years, we have faced a challenging commodity price environment that has impacted our revenues and margins. As a result, we implemented a series of strategic initiatives, which were designed to reposition our portfolio to increase operational and financial flexibility, stabilize the Company financially and improve operational performance.

Repositioning of Our Portfolio

During 2018, we completed the next phase of strategic steps, designed to reposition our portfolio, which allowed us to sharpen our focus on our assets with the highest return. We believe that, in doing so, we will further strengthen our balance sheet and enhance our financial performance. These initiatives included:

- Completing 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”);
- Responding to commodity price changes by shifting focus to our liquids-rich portfolio in Southwest Appalachia; and
- Utilizing a portion of funds realized from the Fayetteville Shale sale to reduce debt and return capital to shareholders. We intend to use the remaining funds to further develop our Appalachian Basin assets in order to accelerate the path to self-funding and for general corporate purposes.

Financial Stability

During 2018, we focused on enhancing our financial stability by:

- Continuing to invest only in those projects that meet our rigorous economic hurdles at strip pricing, adjusting for basis differentials;
- Demonstrating financial discipline by investing within our announced plan of cash flow;
- Identifying and implementing structural, process and organizational changes to further reduce general and administrative costs; and
- Simplifying our capital structure by consolidating the components of our previous credit arrangements into a single senior secured revolving credit facility while increasing liquidity, extending our maturity profile and reducing interest expense.

Operational Improvement

We improved the performance of our large asset portfolio with a primary focus on enhancing margins and investment returns. During 2018, we executed on this part of our business strategy by:

- Lowering our costs through drilling, completions and operational efficiencies and optimizing gathering and transportation costs;
- Focusing on delivering operational excellence with improved well productivity and economics from enhanced completion techniques, initiation of water infrastructure projects, optimization of surface equipment and managing reservoir drawdown; and

Table of Contents

Index to Financial Statements

- Expanding our proved reserve quantities in the Appalachian Basin through our successful drilling program, improved operational performance and improved commodity prices.

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 and, until the Fayetteville Shale sale, natural gas gathering, all of which we historically have referred to as Midstream.

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 the “Appalachian Basin.”

- Our E&P segment recorded operating income of $794 million in 2018, compared to $549 million in 2017. Our E&P segment operating income increased $245 million in 2018 from 2017 primarily due to a $439 million increase in revenues, partially offset by a $194 million increase in operating expenses due primarily to increased gathering and processing fees resulting from a shift in our production growth to the Appalachian Basin.
- Cash flow from operations from our E&P segment was $1.4 billion in 2018, compared to $985 million in 2017. Our cash flow from operations increased in 2018 as the effects of higher realized prices and increased production volumes more than offset increased operating expenses associated with higher liquids activity.

On August 30, 2018, we announced our entry into an agreement to effect the Fayetteville Shale sale. The Fayetteville Shale sale closed on December 3, 2018 resulting in net proceeds of approximately $1,650 million, following adjustments of $215 million primarily related to the net cash flows from the economic effective date to the closing date and certain other working capital adjustments.

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 net 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, 2018, we had 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 2018, we provided drilling rigs for all of our 106 drilled wells. In addition, we provided hydraulic fracturing services utilizing one pressure pumping spread in Southwest Appalachia.

Table of Contents

Index to Financial Statements

Our Proved Reserves

	For the years ended December 31,		
	2018	2017	2016
Proved reserves: (Bcfe)			
Appalachian Basin	11,920	11,088	2,251
Fayetteville Shale	–	3,679	2,997
Other	1	8	5
Total proved reserves	11,921	14,775	5,253
Prices used:			
Natural gas (per Mcf)	$ 3.10	$ 2.98	$ 2.48
Oil (per Bbl)	65.56	47.79	39.25
NGL (per Bbl)	17.64	14.41	6.74
PV-10: (in millions)			
Pre-tax	$ 6,524	$ 5,784	$ 1,665
PV of taxes	(525)	(222)	–
After-tax	$ 5,999	$ 5,562	$ 1,665
Percent of estimated proved reserves that are:			
Natural gas	67%	75%	93%
Proved developed	47%	54%	99%
Percent of operating revenues generated by natural gas sales	78%	85%	89%

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 decreased in 2018, compared to 2017, primarily due to the sale of our Fayetteville Shale E&P assets. 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 the Appalachian Basin.
- The increase in our reserves in 2017 compared to 2016 was primarily due to extensions, discoveries and other additions in the Appalachian Basin along with increases in both price and performance revisions across our portfolio.
- The increase in our after-tax PV-10 value in 2018 compared to 2017 was primarily due to increases in both price and performance revisions in our Appalachian Basin. Excluding the impact of the Fayetteville Shale sale, the increases in our after-tax PV-10 value in both 2018 and 2017, compared to the respective prior years, was primarily due to higher prices and higher reserve levels, including an increasingly larger percentage of oil and NGL reserves.
- 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 17.0 years at year-end 2018,

excluding the production from the Fayetteville Shale.

The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2018 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our year-end 2016 after-tax PV-10 computation did not have future income taxes because our tax basis in the associated natural gas and oil properties exceeded expected pre-tax cash inflows, and thus did not differ from the pre-tax values.

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.

The following table provides an overall and categorical summary of our natural gas, oil and NGL reserves, as of fiscal year-end 2018 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2018, and sets forth 2018 annual information related to production and capital investments for each of our operating areas:

2018 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA (1)

	Appalachia Northeast	Southwest	Other (2)	Total
Estimated proved reserves:				
Natural gas (Bcf):				
Developed	3,327	1,068	–	4,395
Undeveloped	1,039	2,610	–	3,649
	4,366	3,678	–	8,044
Crude oil (MMBbls):				
Developed	–	17.9	0.1	18.0
Undeveloped	–	51.0	–	51.0
	–	68.9	0.1	69.0
Natural gas liquids (MMBbls):				
Developed	–	175.5	–	175.5
Undeveloped	–	401.6	–	401.6
	–	577.1	–	577.1
Total proved reserves (Bcfe) (3):				
Developed	3,327	2,229	1	5,557
Undeveloped	1,039	5,325	–	6,364
	4,366	7,554	1	11,921
Percent of total	37%	63%	0%	100%
Percent proved developed	76%	30%	100%	47%
Percent proved undeveloped	24%	70%	0%	53%
Production (Bcfe)	459	243	244 (4)	946
Capital investments (in millions)	$ 422	$ 691	$ 118 (5)	$ 1,231
Total gross producing wells (6)	666	466	17	1,149
Total net producing wells (6)	592	333	14	939
Total net acreage	184,024	297,445	166,120 (7)	647,589
Net undeveloped acreage	73,174	220,331	153,159 (7)	446,664
PV-10:				
Pre-tax (in millions) (8)	$ 3,054	$ 3,470	$ –	$ 6,524

PV of taxes (in millions) (8)	(245)	(280)	–	(525)
After-tax (in millions) (8)	$ 2,809	$ 3,190	$ –	$ 5,999
Percent of total	47%	53%	0%	100%
Percent operated (9)	99%	100%	100%	99%

(1) The Fayetteville Shale E&P assets and associated reserves were divested on December 3, 2018.

(2) Other reserves and acreage consists primarily of properties in Colorado. Production and capital investing includes Fayetteville Shale.

(3) 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.

(4) Includes 243 Bcf of natural gas production related to our Fayetteville Shale operations which were sold on December 3, 2018.

(5) Other capital investments includes $33 million related to our Fayetteville Shale operations which were sold on December 3, 2018, $60 million related to our water infrastructure project, $16 million related to our E&P service companies and $9 million related to our exploration activities.

(6) Represents producing wells, including 394 wells in which we only have an overriding royalty interest in Northeast Appalachia, used in the December 31, 2018 reserves calculation.

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

(8) 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.

(9) Based upon pre-tax PV-10 of proved developed producing activities.

Table of Contents

Index to Financial Statements

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,		
Net acreage expiring:	2019	2020	2021
Northeast Appalachia	7,429 (3)	3,857	1,837
Southwest Appalachia (1)	21,761 (3)	14,630	6,701
Other			
US – Other Exploration	87,498	30,686	9,032
US – Sand Wash Basin	5,761	989	7
Canada – New Brunswick (2)	–	–	2,518,519

(1) Of this acreage, 9,410 net acres in 2019, 5,300 net acres in 2020 and 2,647 net acres in 2021 can be extended for an average of 4.8 years.

(2) Exploration licenses were extended through 2021 but have been subject to a moratorium since 2015.

(3) We have no reported proved undeveloped locations expiring in 2019.

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 2016, 2017 and 2018:

CHANGES IN PROVED UNDEVELOPED RESERVES

(Bcfe)	Appalachia Northeast	Southwest	Fayetteville Shale (1)	Other (2)	Total
December 31, 2015	314	4	125	–	443
Extensions, discoveries and other additions	–	–	25	–	25
Performance and production revisions (3)	204	–	(1)	–	203
Price revisions	(303)	(4)	(67)	–	(374)
Developed	(181)	–	(39)	–	(220)
Disposition of reserves in place	–	–	–	–	–
Acquisition of reserves in place	–	–	–	–	–
December 31, 2016	34	–	43	–	77
Extensions, discoveries and other additions (4)	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

(1) The Fayetteville Shale E&P assets and associated reserves were sold on December 3, 2018.

(2) Other includes properties principally in Colorado.

(3) Primarily due to changes associated with the analysis of updated data collected in the year and decreases related to current year production.

(4) 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.

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.

- As of December 31, 2018, we had 6,364 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 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 the Appalachian Basin. 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 the Appalachian Basin. 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.
- As of December 31, 2016, we had 77 Bcfe of proved undeveloped reserves. During 2016, we invested $103 million in connection with converting 220 Bcfe, or 50%, of our proved undeveloped reserves as of December 31, 2015 into proved developed reserves and added 25 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale. As a result of the commodity price environment in 2016, we had downward price revisions of 374 Bcfe which were slightly offset by a 203 Bcfe increase due to performance revisions.

Our December 31, 2018 proved reserves included 190 Bcfe of proved undeveloped reserves from 30 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 $24 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 6,364 Bcfe as of December 31, 2018 will require us to invest an additional $3.8 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 business, including our revenues, profits, liquidity, growth, ability to repay our debt and the value of our assets" and "Significant capital expenditures are 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 ability of an E&P company to add 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.

Table of Contents

Index to Financial Statements

In 2018, we replaced 162% of our production volumes with 1,009 Bcfe of proved reserve additions and net upward revisions of 526 Bcfe, essentially all of which were from the Appalachian Basin. Excluding the production from our Fayetteville Shale assets which were divested on December 3, 2018, we replaced 218% of our production in 2018. The following table summarizes the changes in our proved natural gas, oil and NGL reserves for the year ended December 31, 2018:

(in Bcfe)	Appalachia Northeast	Southwest	Fayetteville Shale (1)	Other (2)	Total
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

(1) The Fayetteville Shale E&P assets and associated reserves were divested December 3, 2018.

(2) Other includes properties outside of the Appalachian Basin and Fayetteville Shale.

Our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors "Significant capital expenditures are 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.

Table of Contents

Index to Financial Statements

Our Operations

Northeast Appalachia

Northeast Appalachia represented 49% of our total 2018 net production and 37% of our total reserves as of December 31, 2018. In 2018, our reserves in Northeast Appalachia increased by 240 Bcf, which included net additions of 551 Bcf, net upward price revisions of 41 Bcf and net upward performance revisions of 107 Bcf, partially offset by production of 459 Bcf. As of December 31, 2018, we had approximately 184,024 net acres in Northeast Appalachia and had spud or acquired 680 operated wells, 597 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,				
	2018		2017		2016
Acreage					
Net undeveloped acres	73,174	(1)	87,927	(2)	146,096
Net developed acres	110,850		103,299		99,709
Total net acres	184,024		191,226		245,805
Net Production (Bcf)	459		395		350
Reserves					
Reserves (Bcf)	4,366		4,126		1,574
Locations:					
Proved developed producing	1,042		983		820
Proved developed non-producing	21		25		39
Proved undeveloped	82		100	(3)	2
Total locations (4)	1,145		1,108		861
Gross Operated Well Count Summary					
Spud or acquired	35		58		32
Completed	54		77		33
Wells to sales	60		83		24
Capital Investments (in millions)					
Exploratory and development drilling, including workovers	$ 370		$ 420		$ 160
Acquisition and leasehold	14		14		3
Seismic and other	3		13		2
Capitalized interest and expense	35		42		39

Total capital investments	$ 422	$ 489	$ 204
Average completed well cost (in millions)	$ 7.5	$ 5.9	$ 5.3
Average lateral length (feet)	7,584	6,185	6,142

(1) Our undeveloped acreage position as of December 31, 2018 had an average royalty interest of 15%.
(2) The decrease in our net undeveloped acres in 2017 as compared to 2016 is due to leasehold expirations in areas we did not plan on developing.
(3) Our proved undeveloped reserve locations increased significantly in 2017, as compared to 2016, primarily through our successful drilling program in less developed areas and improved realized commodity pricing.
(4) Includes 394 proved developed producing and 10 proved developed non-producing wells in which we only have an overriding royalty interest.

For 2018 as compared to 2017:

· Our average completed well cost increased primarily due to the drilling of longer lateral wells, new infrastructure due to increased activity in delineation areas and more complex hydraulic fracturing designs.

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 "Midstream" in Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Northeast Appalachia production.

Table of Contents

Index to Financial Statements

Southwest Appalachia

Southwest Appalachia represented 26% of our total 2018 net production and 63% of our total reserves as of December 31, 2018. In 2018, our reserves in Southwest Appalachia increased by 592 Bcfe, which included net additions of 457 Bcfe, net upward price revisions of 106 Bcfe and 272 Bcfe of net upward performance revisions, partially offset by production of 243 Bcfe. As of December 31, 2018, we had approximately 297,445 net acres in Southwest Appalachia and had a total of 436 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,		
	2018	2017	2016
Acreage			
Net undeveloped acres	220,331 (1)	219,709	252,470
Net developed acres	77,114	70,582	69,093
Total net acres	297,445	290,291	321,563
Net Production			
Natural gas (Bcf)	105	85	62
Oil (MBbls)	3,355	2,228	2,041
NGL (MBbls)	19,679	14,193	12,317
Total production (Bcfe) (2)	243	183	148
Reserves			
Reserves (Bcfe)	7,554	6,962	677
Locations:			
Proved developed	423	364	306
Proved developed non-producing	45	37	44
Proved undeveloped	488	559 (3)	–
Total locations	956	960	350
Gross Operated Well Count Summary			
Spud or acquired	62	55	17
Completed	63	50	17
Wells to sales	76	57	18
Capital Investments (in millions)			
Exploratory and development drilling, including workovers	$ 502	$ 353	$ 111
Acquisition and leasehold	37	59	18
Seismic and other	4	4	1
Capitalized interest and expense	148	131	158

Total capital investments (4)	$ 691	$ 547	$ 288
Average completed well cost (in millions) (5) (6)	$ 9.2	$ 7.4	$ 5.4
Average lateral length (feet) (5) (6)	7,267	7,451	5,275

(1) Our undeveloped acreage position as of December 31, 2018 had an average royalty interest of 14%.

(2) Approximately 240 Bcfe, 179 Bcfe and 148 Bcfe for the years ended December 31, 2018, 2017 and 2016, respectively, were produced from the Marcellus Shale formation.

(3) Our proved undeveloped reserve locations increased significantly in 2017, as compared to 2016, primarily through our successful drilling program in less developed areas and improved realized commodity pricing.

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

(5) Includes only wells drilled by the Company.

(6) Average completed well cost and average lateral length for the years ended December 31, 2018, 2017 and 2016 include Marcellus wells only and exclude three Upper Devonian wells in 2018 and one Utica well in 2017 and 2016.

For 2018 as compared to 2017:

- Our average completed well cost increased primarily due to increased completion intensity and larger facilities associated with our liquid-rich wells. The higher well costs are offset by higher liquid production and revenues. In 2018, our NGL and oil production increased by 38% and 46%, respectively, as compared to prior year.

Table of Contents

Index to Financial Statements

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 "Midstream" 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 153,159 net undeveloped acres for the potential development of new resources as of December 31, 2018. This compares to 369,236 net undeveloped acres held at year-end 2017 and 492,389 net undeveloped acres held at year-end 2016, excluding the New Brunswick acreage.

We limited our activities in areas beyond our assets in the Appalachian Basin and the Fayetteville Shale during 2018, 2017 and 2016 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 recognized an impairment of $39 million, net of tax, associated with 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.

In September 2016, we sold approximately 55,000 net acres in West Virginia for approximately $401 million. As of December 2015, these assets included approximately 11 Bcfe of proved reserves.

Table of Contents

Index to Financial Statements

Capital Investments

(in millions)	For the years ended December 31, 2018	2017	2016
E&P Capital Investments by Type			
Exploratory and development drilling, including workovers	$ 895	$ 878	$ 358
Acquisition and leasehold	51	86	23
Seismic expenditures	4	7	1
Water infrastructure project	60	37	–
Drilling rigs, sand facility, and other	15	28	2
Capitalized interest and other expenses	206	212	239
Total E&P capital investments	$ 1,231	$ 1,248	$ 623
E&P Capital Investments by Area			
Northeast Appalachia	$ 422	$ 489	$ 204
Southwest Appalachia	691	547	288
Fayetteville Shale (1)	33	114	86
Other (2)	85	98	45
Total E&P capital investments	$ 1,231	$ 1,248	$ 623

(1) The Fayetteville Shale E&P assets and associated reserves were divested on December 3, 2018.
(2) Includes $60 million and $37 million for the years ended December 31, 2018 and 2017 related to our water infrastructure project.

- The decrease in 2018 E&P capital investing, as compared to 2017, resulted from our commitment to invest within our cash flows from operations, which are heavily dependent on commodity prices.
- The significant increase in 2017 E&P capital investing, as compared to 2016, resulted from the resumption of activity following our decision to suspend drilling activity in the first half of 2016 due to an unfavorable commodity price environment. We began increasing activity in the second half of 2016 as forward pricing improved.
- In 2018, we drilled 106 wells (99 of which were spud in 2018), completed 119 wells, placed 138 wells to sales and had 51 wells in progress at year-end.
- Of the 51 wells in progress at year-end, 25 and 26 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 2019.

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,		
	2018	2017	2016
Average net daily production (MMcfe/day)	2,591	2,456	2,391
Production:			
Natural gas (Bcf)	807	797	788
Oil (MBbls)	3,407	2,327	2,192
NGLs (MBbls)	19,706	14,245	12,372
Total production (Bcfe)	946	897	875

- 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 decrease of 73 Bcf from our Fayetteville Shale properties which were divested on December 3, 2018.
- The increase in production in 2017 resulted primarily from a 45 Bcf increase in net production from our Northeast Appalachia properties and a 35 Bcfe increase in net production from our Southwest Appalachia properties, partially offset by a 59 Bcf decrease in net production from our Fayetteville Shale properties.

Table of Contents

Index to Financial Statements

	For the years ended December 31,		
	2018	2017	2016
Natural Gas Price:			
NYMEX Henry Hub Price ($/MMBtu) (1)	$ 3.09	$ 3.11	$ 2.46
Discount to NYMEX (2)	(0.64)	(0.88)	(0.87)
Average realized gas price per Mcf, excluding derivatives	$ 2.45	$ 2.23	$ 1.59
Gain (loss) on settled financial basis derivatives ($/Mcf)	(0.04)	(0.01)	0.03
Gain (loss) on settled commodity derivatives ($/Mcf)	(0.06)	(0.03)	0.02
Average realized gas price per Mcf, including derivatives	$ 2.35	$ 2.19	$ 1.64
Oil Price:			
WTI oil price ($/Bbl)	$ 64.77	$ 50.96	$ 43.32
Discount to WTI	(7.98)	(7.84)	(12.12)
Average oil price per Bbl, excluding derivatives	$ 56.79	$ 43.12	$ 31.20
Loss on settled derivatives ($/Bbl)	(0.72)	–	–
Average oil price per Bbl, including derivatives	$ 56.07	$ 43.12	$ 31.20
NGL Price:			
Average net realized NGL price per Bbl, excluding derivatives	$ 17.91	$ 14.46	$ 7.46
Gain (loss) on settled derivatives ($/Bbl)	(0.68)	0.02	–
Average net realized NGL price per Bbl, including derivatives	$ 17.23	$ 14.48	$ 7.46
Percentage of WTI, excluding derivatives	28%	28%	17%
Total Weighted Average Realized Price:			
Excluding derivatives ($/Mcfe)	$ 2.66	$ 2.32	$ 1.62
Including derivatives ($/Mcfe)	$ 2.57	$ 2.29	$ 1.66

(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 natural gas, 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, 2018, we had the following commodity price derivatives in place on our targeted future production:

	For the years ended December 31,		
	2019	2020	2021
Natural gas (Bcf)	443	108	37
Oil (MBbls)	675	732	–
Ethane (MBbls)	3,687	732	–
Propane (MBbls)	1,689	–	–

As of February 26, 2019, we had the following commodity price derivatives in place on our targeted future production:

	For the years ended December 31,		
	2019	2020	2021
Natural gas (Bcf)	376	126	37
Oil (MBbls)	566	732	–
Ethane (MBbls)	3,091	732	–
Propane (MBbls)	1,935	366	–

We intend to financially protect pricing on a large portion of expected future production volumes designed to assure 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, 2018.

Table of Contents

Index to Financial Statements

During 2018, the average price we received for our natural gas production, excluding the impact of derivatives, was approximately $0.64 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, 2018, we have entered into physical sales arrangements to protect the basis on approximately 110 Bcf and 45 Bcf of our 2019 and 2020 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately ($0.16) per MMBtu and ($0.23) per MMBtu for 2019 and 2020, respectively.

We have also entered into basis swaps for approximately 107 Bcf and 59 Bcf of our 2019 and 2020 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately ($0.29) per MMBtu and ($0.44) per MMBtu for 2019 and 2020, respectively, as of December 31, 2018.

We refer you to Note 5 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, 2018, we had natural gas delivery commitments of 269 Bcf in 2019 and 89 Bcf in 2020 under existing agreements. These amounts are well below our expected 2019 natural gas production from Northeast Appalachia and Southwest Appalachia and expected 2020 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 contractual obligations 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 contractual obligations 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 Midstream segment. Our customers include major energy companies, utilities and industrial purchasers of natural gas. 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. During the year ended December 31, 2016, no single third-party purchaser accounted for 10% or more of our consolidated revenues. 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.

Table of Contents

Index to Financial Statements

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, or 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 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.

Midstream

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 on December 3, 2018, included all gathering assets associated with our previous operations in Arkansas, which comprised the vast majority of our gathering business.

	For the years ended December 31,		
	2018	2017	2016
Marketing revenues (in millions)	$ 3,497	$ 2,867	$ 2,191
Gathering revenues (in millions)	248	331	378
Total operating revenues (in millions)	3,745	3,198	2,569
Operating income (in millions)	4	183	209
Cash flows from operations (in millions)	$ 70	$ 208	$ 222
Capital investments – gathering (in millions)	9	32	21
Natural gas gathered from the Fayetteville Shale (Bcf)			
Operated wells (Bcf)	355	463	558

Third-party operated wells (Bcf)	26	35	42
Total volumes gathered in the Fayetteville Shale (Bcf)	381	498	600
Volumes marketed (Bcfe)	1,163	1,067	1,062
Percent natural gas marketed from affiliated E&P operations	93%	96%	93%
Percent oil and NGLs marketed from affiliated E&P operations	69%	63%	65%

· Operating income for the year ended December 31, 2018 included $155 million of impairments, primarily related to our 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 Midstream 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.

· Operating income decreased $26 million in 2017 compared to 2016, primarily due to a $47 million decrease in gas gathering revenues related to a decrease in Fayetteville Shale gathered volumes, and a $3 million decrease in marketing margin, partially offset by an $18 million decrease in operating costs and expenses, primarily related to decreased compression rental and maintenance activities, and a $6 million gain on sale of certain compressor equipment.

· Revenues increased in 2018, compared to 2017, as the effect of an increase in the price received for volumes marketed was only partially offset by a decrease in volumes gathered.

· Revenues increased in 2017, compared to 2016, primarily due to an increase in the price received for volumes marketed which was only partially offset by a decrease in volumes gathered.

Table of Contents

Index to Financial Statements

- Cash flow from operations generated by our Midstream segment decreased in 2018, compared to 2017, 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.
- The decrease in cash flow from operations in 2017, compared to 2016, was primarily due to a $26 million decrease in operating income, partially offset by a $12 million increase primarily related to timing differences of payables and receivables between the respective periods.

Gas Gathering

On December 3, 2018, we sold our 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 Appalachia 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 26, 2019:

	For the remaining year ended December 31,		
(MMBtu/d)	2019	2020	2021
Firm transportation	1,305,000	1,325,000	1,316,000
Firm sales	156,000	54,000	35,000
Total firm takeaway – Northeast Appalachia	1,461,000	1,379,000	1,351,000

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 will 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. New ethane cracker demand and export capacity is expected to further strengthen ethane pricing. The table below details our natural gas firm transportation, firm sales and total takeaway capacity over the next three years as of February 26, 2019:

	For the remaining year ended December 31,		
(MMBtu/d)	2019	2020	2021
Firm transportation	694,000	777,000	868,000
Firm sales	8,000	8,000	45,000
Total firm takeaway – Southwest Appalachia	702,000	785,000	913,000

Demand Charges

As of December 31, 2018, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $8.8 billion, $3.1 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 $463 million of that amount. 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, 2018, approximately $221 million of these contractual commitments remain of which we will reimburse the buyer for certain of these potential obligations up to approximately $102 million through 2020 depending on the buyer's actual use. We have recorded an $88 million liability which is the present value of the estimated future payments. The buyer will also assume future asset retirement obligations related to the operations sold.

Table of Contents

Index to Financial Statements

Subsequent to December 31, 2018, 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 us for $133 million.

We refer you to Note 9 – "Commitments and Contingencies" to the consolidated financial statements included in this Annual Report for further details on our demand charges and the risk factor "We have entered into long-term gathering and transportation contracts and have made significant investments in oilfield services businesses, including our drilling rigs, pressure pumping equipment and sand mine operations, to lower costs and secure inputs for our operations and transportation for our production. If our exploration 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. 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. During the year ended December 31, 2016, no single third-party purchaser accounted for 10% or more of our consolidated revenues. 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 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

Our other operations have historically consisted of limited real estate development activities and a natural gas vehicles ("NGV") fueling station in Damascus, Arkansas, which was sold in May 2016. We currently have no significant business activity outside of our E&P and Midstream 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 costs of clean-up operations in limited instances arising out of sudden and

Table of Contents

Index to Financial Statements

accidental events, but otherwise we are not 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 property we have sold, 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 1 of this Annual Report and the risk factor "We 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.

Certain U.S. Statutes. 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 owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport 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 thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in 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. Oil accounted for 2% of our total production in 2018 and 2017 and 1% of our total production in 2016, although we expect this percentage to increase as we continue to develop our Southwest Appalachia assets.

Table of Contents

Index to Financial Statements

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 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. These properties and the wastes disposed on them may be subject to CERCLA, the Clean Water Act, RCRA and analogous state laws. Under such 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.

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.

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 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 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. 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

Table of Contents

Index to Financial Statements

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. We refer you to the risk factor "We 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. The Paris Agreement provides for a four year exit process beginning when it took effect in November 2016, 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.

Table of Contents

Index to Financial Statements

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, 2018, we had 960 total employees, a decrease of 39% compared to year-end 2017, following workforce reductions and the Fayetteville Shale sale. None of our employees were covered by a collective bargaining agreement at year-end 2018. We believe that our relationships with our employees are good.

Executive Officers of the Registrant

The following table shows certain information as of February 26, 2019 about our executive officers, as defined in Rule 3b-7 of the Securities Exchange Act of 1934:

Name	Age	Officer Position
William J. Way	59	President and Chief Executive Officer
Julian M. Bott	56	Executive Vice President and Chief Financial Officer
Clayton A. Carrell	53	Executive Vice President and Chief Operating Officer
J. David Cecil	52	Executive Vice President Corporate Development
Jennifer E. Stewart	55	Senior Vice President – Government & Regulatory Affairs
Jennifer N. McCauley	55	Senior Vice President – Administration
John C. Ale	64	Senior Vice President, General Counsel and Secretary

Jason Kurtz	48	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. Stewart was appointed Senior Vice President – Government & Regulatory Affairs in March 2018. Prior to that, she served as Chief Financial Officer – Interim and Senior Vice President, Tax and Treasury. Ms. Stewart joined the Company in 2010 as Vice President, Tax.

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.

Table of Contents

Index to Financial Statements

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)