EQT Corp
Form 10-K
February 09, 2017
Table of Contents

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, 2016

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

or

FOR THE TRANSITION PERIOD FROM ___________ TO __________

COMMISSION FILE NUMBER 1-3551

EQT CORPORATION
(Exact name of registrant as specified in its charter)

PENNSYLVANIA	25-0464690
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

625 Liberty Avenue	15222

Pittsburgh, Pennsylvania (Zip Code)
(Address of principal executive offices)

Registrant's telephone number, including area code: (412) 553-5700

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

Title of each class	Name of each exchange on which registered
Common Stock, no par value	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 X 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 X

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 X No ___

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes X 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer X Accelerated filer ___
Non-accelerated filer ___ Smaller reporting company ___

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

The aggregate market value of voting stock held by non-affiliates of the registrant as of June 30, 2016: $13.3 billion

The number of shares (in thousands) of common stock outstanding as of January 31, 2017: 172,838

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the annual meeting of shareholders (to be held April 19, 2017) will be filed with the Commission within 120 days after the close of the Company's fiscal year ended December 31, 2016 and is incorporated by reference in Part III to the extent described therein.

Table of Contents

TABLE OF CONTENTS

Table of Contents

Glossary of Commonly Used Terms, Abbreviations and Measurements

Commonly Used Terms

AFUDC (Allowance for Funds Used During Construction) – carrying costs for the construction of certain long-term regulated assets are capitalized and amortized over the related assets' estimated useful lives. The capitalized amount for construction of regulated assets includes interest cost and a designated cost of equity for financing the construction of these regulated assets.

Appalachian Basin – the area of the United States composed of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky and Virginia that lie in the Appalachian Mountains.

basis – when referring to commodity pricing, the difference between the futures price for a commodity and the corresponding sales price at various regional sales points. The differential commonly is related to factors such as product quality, location, transportation capacity availability and contract pricing.

British thermal unit – a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

collar – a financial arrangement that effectively establishes a price range for the underlying commodity. The producer bears the risk and benefit of fluctuation between the minimum (floor) price and the maximum (ceiling) price.

continuous accumulations – natural gas and oil resources that are pervasive throughout large areas, have ill-defined boundaries and typically lack or are unaffected by hydrocarbon-water contacts near the base of the accumulation.

development well – a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

exploratory well – a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

extension well - a well drilled to extend the limits of a known reservoir.

feet of pay – footage penetrated by the drill bit into the target formation.

futures contract – an exchange-traded contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price.

gas – all references to "gas" in this report refer to natural gas.

gross – "gross" natural gas and oil wells or "gross" acres equal the total number of wells or acres in which the Company has a working interest.

hedging – the use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility.

horizontal drilling – drilling that ultimately is horizontal or near horizontal to increase the length of the well bore penetrating the target formation.

horizontal wells – wells that are drilled horizontal or near horizontal to increase the length of the well bore penetrating the target formation.

multiple completion well – a well equipped to produce oil and/or gas separately from more than one reservoir. Such wells contain multiple strings of tubing or other equipment that permit production from the various completions to be measured and accounted for separately.

Table of Contents

Glossary of Commonly Used Terms, Abbreviations and Measurements

natural gas liquids (NGLs) – those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing plants. Natural gas liquids include primarily ethane, propane, butane and iso-butane.

net – “net” natural gas and oil wells or “net” acres are determined by adding the fractional ownership working interests the Company has in gross wells or acres.

net revenue interest – the interest retained by the Company in the revenues from a well or property after giving effect to all third-party interests (equal to 100% minus all royalties on a well or property).

physical basis sales contracts - contracts for the sale of natural gas with physical delivery at a specified location and priced at NYMEX natural gas prices, plus or minus a fixed differential.

play – a proven geological formation that contains commercial amounts of hydrocarbons.

productive well - a well that is producing oil or gas or that is capable of production.

proved reserves – quantities of oil, natural gas, and NGLs which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

proved developed reserves – proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

proved undeveloped reserves (PUDs) – proved reserves that can be estimated with reasonable certainty to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.

reservoir – a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

royalty interest – the land owner’s share of oil or gas production, typically 1/8.

service well - a well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include, among other things, gas injection, water injection and salt-water disposal.

stratographic test well - a drilling effort, geologically directed, to obtain information pertaining to a specific geological condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production.

throughput – the volume of natural gas transported or passing through a pipeline, plant, terminal, or other facility during a particular period.

working gas – the volume of natural gas in the storage reservoir that can be extracted during the normal operation of the storage facility.

working interest – an interest that gives the owner the right to drill, produce and conduct operating activities on a property and receive a share of any production.

Table of Contents

Glossary of Commonly Used Terms, Abbreviations and Measurements

Abbreviations

ASC – Accounting Standards Codification
CFTC – Commodity Futures Trading Commission
EPA – U.S. Environmental Protection Agency
FASB – Financial Accounting Standards Board
FERC – Federal Energy Regulatory Commission
GAAP – U.S. Generally Accepted Accounting Principles
IPO – initial public offering
IRS – Internal Revenue Service
NYMEX – New York Mercantile Exchange
OTC – over the counter
SEC – Securities and Exchange Commission

Measurements

Bbl = barrel
BBtu = billion British thermal units
Bcf = billion cubic feet
Bcfe = billion cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas
Btu = one British thermal unit
Dth = million British thermal units
Mbbl = thousand barrels
Mcf = thousand cubic feet
Mcfe = thousand cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas
MMBtu = million British thermal units
MMcf = million cubic feet
MMcfe = million cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas
TBtu = trillion British thermal units
Tcfe = trillion cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas

Table of Contents

Cautionary Statements

Disclosures in this Annual Report on Form 10-K contain certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Statements that do not relate strictly to historical or current facts are forward-looking and usually identified by the use of words such as “anticipate,” “estimate,” “could,” “would,” “will,” “may,” “forecast,” “approximate,” “expect,” “pr “intend,” “plan,” “believe” and other words of similar meaning in connection with any discussion of future operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this Annual Report on Form 10-K include the matters discussed in the section captioned “Strategy” in Item 1, “Business,” the sections captioned “Outlook” and “Impairment of Oil and Gas Properties” in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and the expectations of plans, strategies, objectives and growth and anticipated financial and operational performance of the Company and its subsidiaries, including guidance regarding the Company’s strategy to develop its Marcellus, Utica, Upper Devonian and other reserves; drilling plans and programs (including the number, type, feet of pay and location of wells to be drilled and the availability of capital to complete these plans and programs); production sales volumes (including liquids volumes) and growth rates; gathering and transmission volumes; the weighted average contract life of firm gathering, transmission and storage contracts; infrastructure programs (including the timing, cost and capacity of the gathering and transmission expansion projects); the timing, cost, capacity and expected interconnects with facilities and pipelines of the Mountain Valley Pipeline (MVP) project; the ultimate terms, partners and structure of Mountain Valley Pipeline, LLC (MVP Joint Venture); technology (including drilling and completion techniques); monetization transactions, including asset sales, joint ventures or other transactions involving the Company’s assets; acquisition transactions; natural gas prices, changes in basis and the impact of commodity prices on the Company's business; reserves, including potential future downward adjustments; potential future impairments of the Company's assets; projected capital expenditures; the amount and timing of any repurchases under the Company’s share repurchase authorization; liquidity and financing requirements, including funding sources and availability; hedging strategy; operation of the Company's fleet vehicles on natural gas; the effects of government regulation and litigation; and tax position. The forward-looking statements included in this Annual Report on Form 10-K involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The Company has based these forward-looking statements on current expectations and assumptions about future events. While the Company considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks and uncertainties, many of which are difficult to predict and beyond the Company’s control. The risks and uncertainties that may affect the operations, performance and results of the Company’s business and forward-looking statements include, but are not limited to, those set forth under Item 1A, “Risk Factors,” and elsewhere in this Annual Report on Form 10-K.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company does not intend to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise.

In reviewing any agreements incorporated by reference in or filed with this Annual Report on Form 10-K, please remember such agreements are included to provide information regarding the terms of such agreements and are not intended to provide any other factual or disclosure information about the Company. The agreements may contain representations and warranties by the Company, which should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to such agreements should those statements prove to be inaccurate. The representations and warranties were made only as of the date of the relevant agreement or such other date or dates as may be specified in such agreement and are subject to more recent developments. Accordingly, these representations and warranties alone may not describe the actual state of affairs of the Company or its affiliates as of the date they were made or at any other time.

6

Table of Contents

PART I

Item 1. Business

General

EQT Corporation (EQT or the Company) conducts its business through three business segments: EQT Production, EQT Gathering and EQT Transmission. EQT Production is the largest natural gas producer in the Appalachian Basin, based on average daily sales volumes, with 13.5 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 3.6 million gross acres, including approximately 790,000 gross acres in the Marcellus play, as of December 31, 2016. EQT Gathering and EQT Transmission provide gathering, transmission and storage services for the Company's produced gas, as well as for independent third parties across the Appalachian Basin, through the Company's ownership and control of EQT Midstream Partners, LP (EQM) (NYSE: EQM), a publicly traded limited partnership formed by EQT to own, operate, acquire and develop midstream assets in the Appalachian Basin.

In 2015, the Company formed EQT GP Holdings, LP (EQGP) (NYSE: EQGP), a Delaware limited partnership, to own the Company's partnership interests, including the incentive distribution rights (IDRs), in EQM. As of December 31, 2016, the Company owned the entire non-economic general partner interest and 239,715,000 common units, which represented a 90.1% limited partner interest, in EQGP. As of December 31, 2016, EQGP's only cash-generating assets were the following EQM partnership interests: 21,811,643 EQM common units, representing a 26.6% limited partner interest in EQM; 1,443,015 EQM general partner units, representing a 1.8% general partner interest in EQM; and all of EQM's IDRs, which entitle EQGP to receive 48.0% of all incremental cash distributed in a quarter after $0.5250 has been distributed in respect of each common unit and general partner unit of EQM for that quarter. The Company is the ultimate parent company of EQGP and EQM.

Due to the Company's ownership and control of EQGP and EQM, the results of EQGP and EQM are both consolidated in the Company's financial statements. The Company records the noncontrolling interests of the public limited partners of EQGP and EQM in its financial statements.

Key Events in 2016

As of September 30, 2016, EQT was the largest natural gas producer in the Appalachian Basin and the fifth largest producer in the United States based on average daily sales volumes. Significant events in 2016 for EQT include:

- EQT achieved record annual production sales volumes, including a 26% increase in total sales volumes and a 31% increase in Marcellus sales volumes. However, the average realized price decreased 20% to $2.47 per Mcfe in 2016 from $3.09 per Mcfe in 2015.

- The Company increased its Marcellus acreage position by acquiring approximately 145,500 net Marcellus acres located primarily in northern West Virginia and southwestern Pennsylvania, including 122,100 net Marcellus acres acquired through the Statoil Acquisition, the Republic Transaction, the Trans Energy Merger and the Pennsylvania Acquisition (as defined in Note 9 to the Consolidated Financial Statements).

- EQM began offering service on the Ohio Valley Connector (OVC) on October 1, 2016. This 37-mile pipeline extends EQM's transmission and storage system from northern West Virginia to Clarington, Ohio, at which point it interconnects with the Rockies Express Pipeline. The OVC is certificated to provide approximately 850 BBtu per day of transmission capacity with an aggregate compression of approximately 38,000 horsepower. EQT has entered into a 20-year precedent agreement with EQM for a total of 650 BBtu per day of firm transmission capacity on the OVC.

- The Company completed two underwritten public common stock offerings, receiving total net proceeds of approximately $1.2 billion for 19,550,000 shares.

- EQM issued 2,949,309 common units through its "At the Market" common unit offering program (the $750 million ATM Program) at an average price per unit of $74.42. EQM received net proceeds of approximately $217.1 million.

- EQM issued $500 million of 4.125% Senior Notes (4.125% Senior Notes) due 2026 for net proceeds of approximately $491.4 million.

Table of Contents

- Effective October 1, 2016, EQT sold to EQM (i) 100% of the outstanding limited liability company interests of Allegheny Valley Connector, LLC and Rager Mountain Storage Company LLC and (ii) certain gathering assets located in southwestern Pennsylvania and northern West Virginia, for $275 million (collectively, the October 2016 Sale).

- On December 28, 2016, the Company sold a gathering system that primarily gathered gas for third-parties for $75.0 million, resulting in an $8.0 million gain.

Business Segments

Prior to the October 2016 Sale, the Company reported its results of operations through two business segments: EQT Production and EQT Midstream. EQT Midstream included the Company’s gathering, transmission and storage businesses as well as the Company's marketing operations that were conducted for the benefit of third-parties. Marketing operations for the benefit of EQT Production were reported in the EQT Production segment. These reporting segments reflected the Company's lines of business and were reported in the same manner in which the Company evaluated its operating performance through September 30, 2016. Following the October 2016 Sale, the Company adjusted its internal reporting structure to align with EQM's operations. These adjustments included transferring to EQT Production (i) the operation of all midstream assets not owned by EQM and (ii) marketing operations conducted for the benefit of third-parties and resulted in changes to the Company's reporting segments effective for this Annual Report on Form 10-K. Under the new reporting structure, the EQT Production segment now includes the Company’s production activities, all of the Company's marketing operations and certain non-core midstream operations primarily supporting the Company's production activities. The EQT Gathering segment contains the Company's gathering assets that are included in EQM. The EQT Transmission segment includes the Company's FERC-regulated interstate pipeline and storage operations. The EQT Gathering and EQT Transmission segments are composed entirely of EQM’s operations and no EQM activities are included within the EQT Production segment. Therefore, the financial and operational disclosures related to EQT Gathering and EQT Transmission in this Annual Report on Form 10-K are the same as EQM’s disclosures in its Annual Report on Form 10-K for the year ended December 31, 2016. The segment disclosures and discussions contained within this Report have been recast to reflect the current reporting structure for all periods presented.

EQT Production Business Segment

EQT Production holds 13.5 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 3.6 million gross acres, including approximately 790,000 gross acres in the Marcellus play, as of December 31, 2016. EQT believes that it is a technology leader in horizontal drilling and completions in the Appalachian Basin and continues to improve its operations through the use of new technology. EQT Production’s strategy is to maximize shareholder value by maintaining an industry leading cost structure to profitably develop its reserves. EQT’s proved reserves increased 35% in 2016, primarily as a result of acquisitions. The Company’s Marcellus assets constituted approximately 11.2 Tcfe of the Company's total proved reserves as of December 31, 2016.

Table of Contents

The following illustration depicts EQT's acreage position within the Marcellus play as of December 31, 2016:

As of December 31, 2016, the Company's proved reserves were as follows:

(Bcfe)	Marcellus	Upper Devonian	Other	Total
Proved Developed	4,732	452	1,659	6,843
Proved Undeveloped	6,468	197	—	6,665
Total Proved Reserves	11,200	649	1,659	13,508

The Company's natural gas wells are generally low-risk, having a long reserve life with relatively low development and production costs on a per unit basis. Assuming that future annual production from these reserves is consistent with 2016, the remaining reserve life of the Company's total proved reserves, as calculated by dividing total proved reserves by calendar year 2016 produced volumes, is 17 years.

Table of Contents

The Company invested approximately $783.0 million on well development during 2016, with total production sales volumes reaching a record high of 759.0 Bcfe, an increase of 26% over the previous year. Capital spending for EQT Production is expected to be approximately $1.5 billion in 2017 (excluding acquisitions), the majority of which will be used to support the drilling of approximately 207 gross wells, including 119 Marcellus wells, 81 Upper Devonian wells and 7 Utica wells. During the past three years, the Company's number of wells drilled (spud) and related capital expenditures for well development were:

	Years Ended December 31,		
	2016	2015	2014
Gross wells spud:			
Horizontal Marcellus*	130	157	237
Other	5	4	108
Total	135	161	345
Capital expenditures for well development (in millions):			
Horizontal Marcellus*	$686	$1,527	$1,456
Other	97	143	261
Total	$783	$1,670	$1,717

* Includes Upper Devonian formations.

As a result of the changes to the Company's reporting segments effective for this Annual Report on Form 10-K, the EQT Production segment includes approximately 6,550 miles of gathering lines. The gathering lines, which are not owned by EQM, primarily support the Company's production operations in non-core areas of declining production. The gathering lines also gather gas for adjacent third-party producers in the Huron play. Revenues for these gathering services are included in Pipeline and Net Marketing Services revenues for the EQT Production segment. These revenues, which are expected to decline over time due to declining production in these areas, were approximately $23.4 million in 2016.

The Company optimizes its contractual processing, transportation and storage assets to sell natural gas and NGLs to marketers, utilities and industrial customers within its operational footprint. The Company provides marketing services for the benefit of EQT Production and third-parties and manages approximately 2.1 Bcf per day of third-party contractual pipeline capacity and 685 MMcf per day of firm third-party processing capacity for the benefit of EQT Production. The Company has also committed to 1.29 Bcf per day of firm capacity on the Mountain Valley Pipeline (MVP) and approximately 200 MMcf per day of additional third-party contractual capacity expected to come online in future periods. The Company currently leases 3.7 Bcf of storage-related assets from third parties.

EQT Gathering Business Segment

As of December 31, 2016, EQT Gathering included approximately 300 miles of high pressure gathering lines with approximately 1.8 Bcf of total firm gathering capacity and multiple interconnect points with EQT Transmission's transmission and storage system. EQT Gathering's system also included approximately 1,500 miles of FERC-regulated low pressure gathering lines.

In the ordinary course of its business, EQT Gathering pursues gathering expansion projects for affiliates and third party producers. EQT Gathering invested approximately $295.3 million on gathering system infrastructure in 2016 and placed 155 MMcf per day of firm gathering capacity into service. EQT Gathering increased gathered volumes by 21% and gathering revenues by 19% in 2016.

In 2017, EQT Gathering will focus on the following gathering expansion projects:

- Range Resources Header Pipeline Project. EQT Gathering expects to complete this project in the second quarter of 2017, including the installation of approximately 25 miles of pipeline and 32,000 horsepower compression. The pipeline is expected to cost approximately $250 million and provide total firm capacity of 600 MMcf per day, which is fully reserved under a ten-year firm capacity reservation commitment contract. EQT Gathering expects to invest approximately $40 million on the project in 2017.

Table of Contents

- Affiliate Gathering System Expansions. EQT Gathering expects to invest $200 million to $230 million in 2017 on gathering system expansion projects in support of development of EQT Production's Marcellus acreage position. These expansions include installing approximately 30 miles of gathering pipeline and 10,000 horsepower of compression across northern West Virginia and southwestern Pennsylvania during 2017.

Gathering System

Table of Contents

EQT Transmission Business Segment

As of December 31, 2016, EQT Transmission's transmission and storage system included an approximately 950-mile FERC-regulated interstate pipeline that connects to six interstate pipelines and multiple distribution companies. The six interstate pipelines are Texas Eastern, Dominion Transmission, Columbia Gas Transmission, Tennessee Gas Pipeline Company, Rockies Express Pipeline LLC and National Fuel Gas Supply Corporation. The transmission system is supported by 18 associated natural gas storage reservoirs with approximately 645 MMcf per day of peak withdrawal capacity, 43 Bcf of working gas capacity and 41 compressor units, with total throughput capacity of approximately 4.3 Bcf per day as of December 31, 2016.

In the ordinary course of its business, EQT Transmission pursues transmission projects aimed at profitably increasing system capacity. EQT Transmission invested approximately $292.0 million on transmission and storage system infrastructure in 2016. EQT Transmission placed the OVC project in-service in 2016 at an estimated total cost of approximately $365 million, excluding AFUDC, of which $214 million was spent in 2016. EQT Transmission also spent $78 million on other transmission system projects in 2016. These projects increased total throughput capacity by approximately 700 MMcf in 2016, and revenues increased by approximately $40.3 million or 13.5% in 2016.

In 2017, EQT Transmission will focus on the following transmission projects:

- Mountain Valley Pipeline. The MVP Joint Venture is a joint venture with affiliates of each of NextEra Energy, Inc., Consolidated Edison, Inc., WGL Holdings, Inc. and RGC Resources, Inc. EQM is the operator of the MVP and owned a 45.5% interest in the MVP Joint Venture as of December 31, 2016. The 42 inch diameter MVP has a targeted capacity of 2.0 Bcf per day and is estimated to span 300-miles extending from EQT Transmission's existing transmission and storage system in Wetzel County, West Virginia to Pittsylvania County, Virginia. As currently designed, the MVP is estimated to cost a total of $3.0 billion to $3.5 billion, excluding AFUDC, with EQM funding its proportionate share through capital contributions made to the joint venture. In 2017, EQM expects to provide capital contributions of $200 million to $500 million to the MVP Joint Venture, primarily in support of materials, land, engineering design, environmental work and construction activities. The MVP Joint Venture has secured a total of 2.0 Bcf per day of firm capacity commitments at 20-year terms, including a 1.29 Bcf per day firm capacity commitment by EQT, and is currently in negotiation with additional shippers who have expressed interest in the MVP project. The FERC issued the Draft Environmental Impact Statement for the project in September 2016 and is currently working to develop the Final Environmental Impact Statement. The pipeline is targeted to be placed in-service during the fourth quarter of 2018.

- Transmission Expansion. EQT Transmission plans to invest $60 million to $80 million on transmission expansion projects in 2017, including Equitrans expansion projects and modernization projects on the Allegheny Valley Connector (AVC) facilities. The Equitrans expansion projects are designed to increase deliverable capacity to EQT Transmission's Mobley hub, which is the origin of both the OVC and the MVP. The projects include additional compression, pipeline looping and new header pipelines. In total, the projects are expected to add up to 1.5 Bcf per day of capacity by the end of 2018, consistent with the target MVP in-service date. The AVC modernization projects primarily consist of the replacement of approximately 20 miles of pipeline.

Table of Contents

Transmission and Storage System

Table of Contents

Strategy

EQT's strategy is to maximize shareholder value by profitably developing its undeveloped reserves, and effectively and efficiently utilizing EQM's extensive gathering and transmission assets that are uniquely positioned across the Marcellus, Upper Devonian and Utica Shales while maintaining an industry leading cost structure.

EQT believes that it is a technology leader in horizontal drilling and completion in the Appalachian Basin and continues to improve its operations through the use of new technology. Over 90% of the Company's acreage is held by production or in fee; therefore, EQT Production is able to develop its acreage in the most economical manner through the use of longer laterals and multi-well pads, as opposed to being required to drill less-economical wells in order to retain acreage. The use of multi-well pads, in conjunction with a completion technique known as reduced cluster spacing, has the additional benefit of reducing the overall environmental surface footprint of the Company's drilling operations.

EQM's midstream assets span a wide area of the Marcellus, Upper Devonian and Utica Shales in southwestern Pennsylvania and northern West Virginia. This footprint provides a competitive advantage that uniquely positions the Company for continued growth. EQM intends to capitalize on the growing need for gathering and transmission infrastructure in this region, including the need for midstream header connectivity to interstate pipelines in Pennsylvania and West Virginia.

The ongoing efforts of EQGP and EQM are an important support mechanism for EQT's overall business strategy. Through capitalizing on economically attractive organic growth opportunities and attracting additional third-party volumes, EQM is expected to grow profitably and provide an ongoing source of capital to the Company.

See "Capital Resources and Liquidity" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report on Form 10-K for details regarding the Company's capital expenditures.

Markets and Customers

Natural Gas Sales: The Company's produced natural gas is sold to marketers, utilities and industrial customers located mainly in the Appalachian Basin and the Northeastern United States. The Company's current transportation portfolio also enables the Company to reach markets along the Gulf Coast and Midwestern portions of the United States. Natural gas is a commodity and therefore the Company typically receives market-based pricing. The market price for natural gas in the Appalachian Basin continues to be lower relative to the price at Henry Hub, Louisiana (the location for pricing NYMEX natural gas futures) as a result of the increased supply of natural gas in the Northeast region. In order to protect cash flow from undue exposure to the risk of changing commodity prices, the Company hedges a portion of its forecasted natural gas production, most of which is hedged at NYMEX natural gas prices. The Company's hedging strategy and information regarding its derivative instruments is set forth under the heading "Commodity Risk Management" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," and in Notes 1 and 6 to the Consolidated Financial Statements.

The Company is also helping to build additional demand for natural gas. In mid-2011, EQT opened a public-access natural gas fueling station in Pittsburgh, Pennsylvania. As a result of growing demand for compressed natural gas for numerous fleets throughout the region, the station added two more dispensers in 2013. In addition, the Company promotes the use of natural gas with its own fleet vehicles and plans to operate 11% of its light-duty vehicle fleet, more than 110 vehicles, on natural gas by the end of 2017. All of the Company's contracted drilling rigs and completion crews utilize natural gas.

NGLs Sales: The Company sells NGLs from its own gas production and from gas marketed for third parties. In its Appalachian operations, the Company primarily contracts with MarkWest Energy Partners, L.P. (MarkWest) to process natural gas in order to extract the heavier hydrocarbon stream (consisting predominately of ethane, propane, iso-butane, normal butane and natural gasoline) primarily from EQT Production's produced gas. The Company also contracts with MarkWest to market NGLs, with the exception of ethane. The Company also has contractual processing arrangements with Williams Ohio Valley Midstream LLC to market NGLs on behalf of the Company in its Appalachian operations. In its Permian Basin operations, the Company sells gas to third-party processors at a weighted average liquids component price.

Table of Contents

The following table presents the average sales price on an average per Mcfe basis to EQT Corporation for sales of produced natural gas, NGLs and oil, with and without cash settled derivatives, for the years ended December 31:

	2016	2015	2014
Average sales price per Mcfe sold (excluding cash settled derivatives)	$1.99	$2.38	$4.48
Average sales price per Mcfe sold (including cash settled derivatives)	$2.47	$3.09	$4.50

In addition, price information for all products is included in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," under the caption "Consolidated Operational Data," and incorporated herein by reference.

Natural Gas Gathering: EQT Production accounted for approximately 96% and 91% of EQT Gathering's gathering revenues and volumes, respectively, for 2016.

EQT Gathering has various firm gas gathering agreements which provide for firm reservation fees in certain high pressure development areas. Including expected future capacity from expansion projects that are not yet fully constructed but for which EQM had entered into firm gathering agreements, approximately 2.5 Bcf per day of firm gathering capacity was subscribed under firm gathering contracts as of December 31, 2016. The weighted average remaining term of EQT Gathering's firm gathering contracts was approximately 9 years as of December 31, 2016, based on total projected contracted revenues.

On EQT Gathering's low pressure FERC-regulated gathering system, the primary term of a typical gathering agreement is one year with month-to-month roll over provisions terminable upon at least 30 days notice. The rates for gathering service on the regulated system are based on the maximum posted tariff rate and assessed on actual receipts into the gathering system. EQT Gathering retains a percentage of wellhead natural gas receipts to recover natural gas used to run its compressor stations and for other requirements on all of its gathering systems.

Natural Gas Transmission and Storage: EQT Transmission's customers are affiliates and third-parties primarily in the northeastern United States. In 2016, approximately 73% of transmission volumes and 51% of transmission revenues were from EQT Production. Other customers include local distribution companies, other independent producers and marketers in the Appalachian Basin.

EQT Transmission generally does not take title to the natural gas transported or stored for its customers. EQT Transmission generally provides transmission and storage services in two manners: firm service and interruptible service. The fixed monthly fee under a firm contract is referred to as a capacity reservation fee, which is recognized ratably over the contract period based on the contracted volume regardless of the amount of natural gas that is transported or stored. In addition to capacity reservation fees, EQT Transmission may also collect usage fees when a firm transmission customer uses the capacity it has reserved under these firm transmission contracts. Where applicable, the usage fees are assessed on the actual volume of natural gas transported on the system. A firm customer is billed an additional usage fee on volumes in excess of firm capacity when the level of natural gas received for delivery from the customer exceeds its reserved capacity. Customers are not assured capacity or service for volumes in excess of firm capacity on the applicable pipeline as these volumes have the same priority as interruptible service.

Under interruptible service contracts, customers pay usage fees based on their actual utilization of assets. Customers that have executed interruptible contracts are not assured capacity or service on the applicable systems. To the extent that physical capacity that is contracted for firm service is not fully utilized or excess capacity that has not been contracted for service exists, the system can allocate such capacity to interruptible services.

Including expected future capacity from expansion projects that are not yet fully constructed but for which EQM has entered into firm contracts, approximately 4.7 Bcf per day of transmission capacity and 31.3 Bcf of storage capacity, respectively, were subscribed under firm transmission and storage contracts as of December 31, 2016. EQT Transmission's firm transmission and storage contracts had a weighted average remaining term of approximately 16 years as of December 31, 2016 based on total projected contracted revenues.

As of December 31, 2016, approximately 92% of EQT Transmission's contracted transmission firm capacity was subscribed by customers under negotiated rate agreements under its tariff. The remaining 8% of EQT Transmission’s contracted transmission firm capacity was subscribed at the recourse rates under its tariff, which are the maximum rates an interstate pipeline may charge for its services under its tariff.

Table of Contents

EQT Transmission has an acreage dedication from EQT pursuant to which EQT Transmission has the right to elect to transport on its transmission and storage system all natural gas produced from wells drilled by EQT under an area covering approximately 60,000 acres in Allegheny, Washington and Greene counties in Pennsylvania and Wetzel, Marion, Taylor, Tyler, Doddridge, Harrison and Lewis counties in West Virginia. EQT has a significant natural gas drilling program in these areas.

Natural Gas Marketing: EQT Energy, LLC (EQT Energy), EQT's indirect wholly owned marketing subsidiary, provides marketing services and contractual pipeline capacity management for the benefit of EQT Production and third-parties. EQT Energy also engages in risk management and hedging activities on behalf of EQT Production, the objective of which is to limit the Company’s exposure to shifts in market prices. EQT Energy leases third-party storage capacity in order to take advantage of seasonal spreads, where available.

No single customer accounted for more than 10% of EQT's total operating revenues for 2016. One customer within the EQT Production segment accounted for approximately 10% and 12% of EQT's total operating revenues in 2015 and 2014, respectively. The Company believes that the loss of this customer would not have a material adverse effect on its business because alternative customers for the Company's natural gas are available.

Competition

Natural gas producers compete in the acquisition of properties, the search for and development of reserves, the production, transportation and sale of natural gas and NGLs and the securing of services, labor and equipment required to conduct operations. Competitors include independent oil and gas companies, major oil and gas companies and individual producers and operators. Competition for natural gas gathering, transmission and storage volumes is primarily based on rates, customer commitment levels, timing, performance, commercial terms, reliability, service levels, location, reputation and fuel efficiencies. Key competitors in the natural gas transmission and storage market include companies that own major natural gas pipelines. Key competitors for gathering systems include companies that own major natural gas pipelines, independent gas gatherers and integrated energy companies. EQT competes with numerous companies when marketing natural gas and NGLs. Some of these competitors are affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users.

Regulation

Regulation of the Company’s Operations

EQT Production’s exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances. These regulations and any delays in obtaining related authorizations may affect the costs and timing of developing EQT Production’s natural gas resources.

EQT Production’s operations are also subject to conservation and correlative rights regulations, including the regulation of the size of drilling and spacing units or field rule units; setbacks; the number of wells that may be drilled in a unit or in close proximity to other wells; drilling in the vicinity of coal mining operations and certain other structures; and the unitization or pooling of natural gas properties. Kentucky, Ohio, Virginia and, for Utica or other deep wells, West Virginia allow the statutory pooling or unitization of tracts to facilitate development and exploration. In West Virginia, the Company must rely on voluntary pooling of lands and leases for Marcellus and Upper Devonian acreage. In 2013, the Pennsylvania legislature enacted lease integration legislation, which authorizes joint development of existing contiguous leases, and Texas permits similar joint development. In addition, state conservation and oil and gas laws generally limit the venting or flaring of natural gas, and Texas sets production allowances on the amount of annual production permitted from a well.

The Company's gathering and transmission operations are subject to various types of federal and state environmental laws and local zoning ordinances, including air permitting requirements for compressor station and dehydration units and other permitting requirements; erosion and sediment control requirements for compressor station and pipeline construction projects; waste management requirements and spill prevention plans for compressor stations; various recordkeeping and reporting requirements for air permits and waste management practices; compliance with safety regulations; and siting and noise regulations for compressor stations and transmission facilities. These regulations may increase the costs of operating existing pipelines and compressor stations and increase the costs of, and the time to develop, new or expanded pipelines and compressor stations.

Table of Contents

The Company's interstate natural gas transmission and storage operations are regulated by the FERC, and certain gathering lines are also subject to rate regulation by the FERC. For instance, the FERC approves tariffs that establish EQM's rates, cost recovery mechanisms and other terms and conditions of service applicable to its FERC-regulated assets. The fees or rates established under EQM's tariffs are a function of its costs of providing services to customers, including a reasonable return on invested capital. The FERC's authority over transmission operations also extends to: storage and related services; certification and construction of new interstate transmission and storage facilities; extension or abandonment of interstate transmission and storage services and facilities; maintenance of accounts and records; relationships between pipelines and certain affiliates; terms and conditions of service; depreciation and amortization policies; acquisition and disposition of facilities; the safety of pipelines; and initiation and discontinuation of services.

In 2010, the U.S. Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivative market and entities, such as the Company, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), required the CFTC, the SEC and other regulatory agencies to promulgate rules and regulations implementing this legislation. As of the filing date of this Annual Report on Form 10-K, the CFTC had adopted and implemented many final rules that impose regulatory obligations on all market participants, including the Company, such as recordkeeping and certain reporting obligations. Other CFTC rules that may be relevant to the Company have yet to be finalized. Because significant CFTC rules relevant to natural gas hedging activities are still at the proposal stage, it is not possible at this time to predict the extent of the impact of the regulations on the Company's hedging program or regulatory compliance obligations. The Company has experienced increased, and expects additional, compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

Regulators periodically review or audit the Company's compliance with applicable regulatory requirements. The Company anticipates that compliance with existing laws and regulations governing current operations will not have a material adverse effect upon its capital expenditures, earnings or competitive position. Additional proposals that affect the oil and gas industry are regularly considered by the U.S. Congress, the states, regulatory agencies and the courts. The Company cannot predict when or whether any such proposals may become effective or the effect that such proposals may have on the Company.

Environmental, Health and Safety Regulation

The business operations of the Company are also subject to various federal, state and local environmental, health and safety laws and regulations pertaining to, among other things, the release, emission or discharge of materials into the environment; the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes); the safety of employees and the general public; pollution; site remediation; and preservation or protection of human health and safety, natural resources, wildlife and the environment. The Company must take into account environmental, health and safety regulations in, among other things, planning, designing, constructing, operating and abandoning wells, pipelines and related facilities.

The Company has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material to the Company's financial position, results of operations or liquidity.

Vast quantities of natural gas deposits exist in shale and other formations. It is customary in the Company's industry to recover natural gas from these shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into a shale gas formation. These deeper formations are geologically separated and isolated from fresh ground water supplies by overlying rock layers. The Company’s well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers. To assess water sources near our drilling locations, the Company conducts baseline and, as appropriate, post-drilling water testing at all water wells within at least 2,500 feet of the Company's drilling pads. Legislative and regulatory efforts at the federal level and in some states have sought to render more stringent permitting and compliance requirements for hydraulic fracturing. If passed into law, the additional permitting requirements for hydraulic fracturing may increase the cost to or limit the Company’s ability to obtain permits to construct wells.

See Note 20 to the Consolidated Financial Statements for a description of expenditures related to environmental matters.

Climate Change

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. The EPA and various states have issued a number of proposed and final laws and regulations that

17

Table of Contents

limit greenhouse gas emissions. Legislation or regulation that restricts carbon emissions could increase the Company's cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. Climate change and greenhouse gas legislation or regulation could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Conversely, legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because the combustion of natural gas results in substantially fewer carbon emissions per Btu of heat generated than other fossil fuels, such as coal. The effect on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

Employees

The Company and its subsidiaries had 1,809 employees at the end of 2016; none are subject to a collective bargaining agreement.

Availability of Reports

The Company makes certain filings with the SEC, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through its website, http://www.eqt.com, as soon as reasonably practicable after they are filed with, or furnished to, the SEC. The filings are also available at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. These filings are also available on the internet at http://www.sec.gov.

Composition of Segment Operating Revenues

Presented below are operating revenues for each class of products and services representing greater than 10% of total operating revenues.

	For the Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Operating Revenues:			
Sales of natural gas, oil and NGLs (a)	$1,594,997	$1,690,360	$2,132,409
Pipeline and net marketing services (b)	262,342	263,640	256,359
(Loss) gain on derivatives not designated as hedges (a)	(248,991)	385,762	80,942
Total operating revenues	$1,608,348	$2,339,762	$2,469,710

(a) Reported in EQT Production segment.

(b) Reported in EQT Gathering and EQT Transmission segments, with the exception of $41.0 million, $55.5 million and $71.8 million for the years ended December 31, 2016, 2015 and 2014, respectively, which are reported within the EQT Production segment.

Financial Information about Segments

See Note 5 to the Consolidated Financial Statements for financial information by business segment including, but not limited to, revenues from external customers, operating income and total assets.

Jurisdiction and Year of Formation

The Company is a Pennsylvania corporation formed in 2008 in connection with a holding company reorganization of the former Equitable Resources, Inc.

Financial Information about Geographic Areas

Substantially all of the Company's assets and operations are located in the continental United States.

Table of Contents

Item 1A. Risk Factors

In addition to the other information contained in this Annual Report on Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. Please note that additional risks not presently known to us or that are currently considered immaterial may also have a negative impact on our business and operations. If any of the events or circumstances described below actually occurs, our business, financial condition or results of operations could suffer and the trading price of our common stock could decline.

Natural gas, NGLs and oil price volatility, or a prolonged period of low natural gas, NGLs and oil prices, may have an adverse effect upon our revenue, profitability, future rate of growth, liquidity and financial position.

Our revenue, profitability, future rate of growth, liquidity and financial position depend upon the prices for natural gas, NGLs and oil. The prices for natural gas, NGLs and oil have historically been volatile, and we expect this volatility to continue in the future. The prices are affected by a number of factors beyond our control, which include: weather conditions and seasonal trends; the supply of and demand for natural gas, NGLs and oil; regional basis differentials; national and worldwide economic and political conditions; new and competing exploratory finds of natural gas, NGLs and oil; the ability to export liquefied natural gas; the effect of energy conservation efforts; the price and availability of alternative fuels; the availability, proximity and capacity of pipelines, other transportation facilities, and gathering, processing and storage facilities; and government regulations, such as regulation of natural gas transportation and price controls.

The market prices for natural gas, NGLs and oil were depressed throughout 2015 and 2016. The daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $3.76 per MMBtu to a low of $1.49 per MMBtu from January 1, 2015 through December 31, 2016, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $61.13 per barrel to a low of $26.51 per barrel during the same period. In addition, the market price for natural gas in the Appalachian Basin continues to be lower relative to NYMEX Henry Hub as a result of the significant increases in the supply of natural gas in the Northeast region in recent years. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas, including Appalachian basis, NGLs and oil and thus cannot predict the ultimate impact of prices on our operations. However, we do expect natural gas and NGLs prices, particularly in the Appalachian Basin, to remain depressed during 2017.

The depressed price environment for natural gas, NGLs and oil during 2015 and 2016 has resulted in lower revenues, operating income and cash flows. Prolonged low, and/or significant or extended further declines in, natural gas, NGLs and oil prices may result in further decreases in our revenues, operating income and cash flows, which may result in reductions in drilling activity, delays in the construction of new midstream infrastructure and downgrades, or other negative rating actions with respect to our credit ratings. Further declines in prices could also adversely affect the amount of natural gas, NGLs and oil that we can produce economically, which may result in the Company having to make significant downward adjustments to the value of our assets and could cause us to incur additional non-cash impairment charges to earnings in future periods. See “Impairment of Oil and Gas Properties” under Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Recent natural gas, NGLs and oil price declines have resulted in impairment of certain of our non-core assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance may result in additional write-downs of the carrying amounts of our assets, which could materially and adversely affect our results of operations in future periods.” Moreover, a failure to control our development costs during periods of lower natural gas, NGLs and oil prices could have significant adverse effects on our earnings, cash flows and financial position. We are also exposed to the risk of non-performance by our hedge counterparties in the event that changes, positive or negative, in natural gas prices result in derivative contracts with a positive fair value.

Increases in natural gas, NGLs and oil prices may be accompanied by or result in increased well drilling costs, increased production taxes, increased lease operating expenses, increased volatility in seasonal gas price spreads for our storage assets and increased end-user conservation or conversion to alternative fuels. Significant natural gas price increases may subject us to margin calls on our commodity price derivative contracts (hedging arrangements, including swap, collar and option agreements and exchange-traded instruments) which would potentially require us to post significant amounts of cash collateral with our hedge counterparties. The cash collateral provided to our hedge counterparties, which is interest-bearing, is returned to us in whole or in part upon a reduction in forward market prices, depending on the amount of such reduction, or in whole upon settlement of the related derivative contract. In addition, to the extent we have hedged our current production at prices below the current market price, we are unable to benefit fully from an increase in the price of natural gas.

Table of Contents

We are subject to risks associated with the operation of our wells, pipelines and facilities.

Our business is subject to all of the inherent hazards and risks normally incidental to the operations for drilling, producing, transporting and storing natural gas, NGLs and oil, such as well site blowouts, cratering and explosions, pipe and other equipment and system failures, fires, formations with abnormal or unexpected pressures, freeze offs of wells and pipelines due to cold weather, pollution and environmental risks and natural disasters. We also face various threats to the security of our or third parties' facilities and infrastructure, such as processing plants, compressor stations and pipelines. These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment, pollution or other environmental damage, disruptions to our operations, regulatory investigations and penalties and loss of sensitive confidential information. Moreover, in the event that one or more of these hazards occur, there can be no assurance that a response will be adequate to limit or reduce damage. As a result of these risks, we are also sometimes a defendant in legal proceedings and litigation arising in the ordinary course of business. There can be no assurance that the insurance policies we maintain to limit our liability for such losses will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices or to cover all risks.

Our failure to develop, obtain, access or maintain the necessary infrastructure to successfully deliver natural gas, NGLs and oil to market may adversely affect our earnings, cash flows and results of operations.

Our delivery of natural gas, NGLs and oil depends upon the availability, proximity and capacity of pipelines, other transportation facilities and gathering and processing facilities. The capacity of transmission, gathering and processing facilities may be insufficient to accommodate potential production from existing and new wells, which may result in substantial discounts in the prices we receive for our natural gas, NGLs and oil. Competition for pipeline infrastructure within the Appalachian Basin is intense, and many of our competitors have substantially greater financial resources than we do, which could affect our competitive position. The Company's investment in midstream infrastructure through EQM is intended to address a lack of capacity on, and access to, existing gathering and transmission pipelines as well as curtailments on such pipelines. Our infrastructure development and maintenance programs can involve significant risks, including those related to timing, cost overruns and operational efficiency, and these risks can be affected by the availability of capital, materials and qualified contractors and work force, as well as weather conditions, natural gas, NGLs and oil price volatility, delays in obtaining permits and other government approvals, title and property access problems, geology, public opposition to infrastructure development, compliance by third parties with their contractual obligations to us and other factors. Moreover, if our infrastructure development and maintenance programs are not successfully developed on time and within budget, we may not be able to profitably fulfill our contractual obligations to third parties, including joint venture partners.

We also deliver to and are served by third-party natural gas, NGLs and oil transmission, gathering, processing and storage facilities that are limited in number, geographically concentrated and subject to the same risks identified above with respect to our infrastructure development and maintenance programs. Because we do not own these third-party pipelines or facilities, their continuing operation is not within our control. An extended interruption of access to or service from our or third-party pipelines and facilities for any reason, including cyber-attacks on such pipelines and facilities or service interruptions due to gas quality, could result in adverse consequences to us, such as delays in producing and selling our natural gas, NGLs and oil. In such an event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at prices lower than market prices or at prices lower than we currently project. In addition, some of our third-party contracts involve significant long-term financial commitments on our part. Moreover, our usage of third parties for transmission, gathering and processing services subjects us to the credit and performance risk of such third parties and may make us dependent upon those third parties to get our produced natural gas, NGLs and oil to market.

Also, our producing properties and operations are primarily in the Appalachian Basin, making us vulnerable to risks associated with operating in limited geographic areas. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of natural gas and NGLs produced from this area.

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

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our 2017 business plan, we considered allocating capital and other resources to various aspects of our businesses, including well development, reserve acquisitions, exploratory activities, midstream infrastructure, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2017 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, including the appropriate corporate structure, appropriate rate of reserve development, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2017 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

We periodically engage in acquisitions, dispositions and other strategic transactions, including joint ventures. These transactions involve various inherent risks, such as our ability to obtain the necessary regulatory approvals; the timing of and conditions imposed upon us by regulators in connection with such approvals; the assumption of potential environmental or other liabilities; and our ability to realize the benefits expected from the transactions. In addition, various factors including prevailing market conditions could negatively impact the benefits we receive from transactions. Competition for acquisition opportunities in our industry is intense and may increase the cost of, or cause us to refrain from, completing acquisitions. Joint venture arrangements may restrict our operational and corporate flexibility. Moreover, joint venture arrangements involve various risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may have little control over, and our joint venture partners may not satisfy their obligations to the joint venture. Our inability to complete a transaction or to achieve our strategic or financial goals in any transaction could have significant adverse effects on our earnings, cash flows and financial position.

Our need to comply with comprehensive, complex and sometimes unpredictable government regulations may increase our costs and limit our revenue growth, which may result in reduced earnings.

Our operations are regulated extensively at the federal, state and local levels. Laws, regulations and other legal requirements have increased the cost to plan, design, drill, install, operate and abandon wells, gathering and transmission systems and pipelines. Our exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of water and other fluids and materials, including solid wastes, incidental to oil and gas operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances. These regulations and any delays in obtaining related authorizations may affect the costs and timing of developing our natural gas resources.

Our operations are also subject to conservation and correlative rights regulations, including the regulation of the size of drilling and spacing units or field rule units; setbacks; the number of wells that may be drilled in a unit or in close proximity to other wells; drilling in the vicinity of coal mining operations and certain other structures; and the unitization or pooling of natural gas properties. Some states allow the statutory pooling and unitization of tracts to facilitate development and exploration, as well as joint development of existing contiguous leases. In addition, state conservation and oil and gas laws generally limit the venting or flaring of natural gas, and may set production allowances on the amount of annual production permitted from a well.

Environmental, health and safety legal requirements govern discharges of substances into the air, ground and water; the management and disposal of hazardous substances and wastes; the clean-up of contaminated sites; groundwater quality and availability; plant and wildlife protection; locations available for drilling and pipeline construction; environmental impact studies and assessments prior to permitting; restoration of drilling properties after drilling is completed; pipeline safety (including replacement requirements); and work practices related to employee health and safety. Compliance with the laws, regulations and other legal requirements applicable to our businesses may increase our cost of doing business or result in delays due to the need to obtain additional or more detailed governmental approvals and permits. These requirements could also subject us to claims for personal injuries, property damage and other damages. Our failure to comply with the laws, regulations and other legal requirements applicable to our businesses, even if as a result of factors beyond our control, could result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and damages.

The rates charged to customers by our gathering, transmission and storage businesses are, in many cases, subject to federal regulation by the FERC, which may prohibit us from realizing a level of return that we believe is appropriate. These restrictions may take the form of lower overall rates, imputed revenue credits, cost disallowances and/or expense deferrals. For example, under current policy, the FERC permits interstate pipelines to include an income tax allowance in the cost-of-service used as the basis for calculating their regulated rates. For pipelines owned by partnerships, including EQM, the tax allowance reflects the actual or potential income tax liability on the FERC-jurisdictional income attributable to all partnership interests if the ultimate owner of the interest has an actual or potential income tax liability on such income. If the FERC's income tax allowance policy, which is subject of legal challenges, were to change and if the FERC were to disallow all or a substantial portion of the current income tax

Table of Contents

allowance for EQM’s pipelines, EQM’s regulated rates, and therefore its revenues, could be materially adversely affected, which eventually could have a material adverse effect on our earnings and cash flows.

Certain natural gas gathering facilities are exempted from regulation by the FERC. We believe that many of our natural gas facilities meet the traditional tests the FERC has used to establish a pipeline's status as an exempt gatherer not subject to regulation as a natural gas company, although the FERC has not made a formal determination with respect to the jurisdictional status of those facilities. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation within the industry, so the classification and regulation of some of our facilities may be subject to change based on future determinations by the FERC, the courts or the U.S. Congress.

Failure to comply with applicable provisions of the laws governing the regulation and safety of natural gas gathering, transmission and storage facilities, as well as with the regulations, rules, orders, restrictions and conditions associated with these laws, could result in the imposition of administrative and criminal remedies and civil penalties. For example, the FERC is authorized to impose civil penalties of up to approximately $1.2 million per violation, per day for violations of the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 or the rules, regulations, restrictions, conditions and orders promulgated under those statutes. The violation of federal pipeline safety laws could lead to the imposition of civil penalties of up to $200,000 per day for each violation up to a maximum penalty of $2,000,000 for a related series of violations. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation.

Laws, regulations and other legal requirements are constantly changing, and implementation of compliant processes in response to such changes could be costly and time consuming. In addition to periodic changes to air, water and waste laws, as well as recent EPA initiatives to impose climate change-based air regulations on the industry, the U.S. Congress and various states have been evaluating and, in certain cases, have enacted climate-related legislation and other regulatory initiatives that would further restrict emissions of greenhouse gases, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of burning natural gas). Such restrictions may result in additional compliance obligations with respect to, or taxes on the release, capture and use of, greenhouse gases that could have an adverse effect on our operations.

Another area of regulation is hydraulic fracturing, which we utilize to complete most of our natural gas wells. Certain environmental and other groups have suggested that additional laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and legislation or regulation has been proposed or is under discussion at federal, state and local levels. For instance, legislation or regulation banning hydraulic fracturing has been adopted in a number of jurisdictions in which we do not have drilling operations. We cannot predict whether any other such federal, state or local legislation or regulation will be enacted and, if enacted, how it may affect our operations, but enactment of additional laws or regulations could increase our operating costs, result in delays in production or delivery of natural gas or perhaps even preclude us from drilling wells.

Proposals that could potentially increase and accelerate the payment of federal and collaterally state income taxes of independent producers are occasionally discussed in connection with the federal budget, with the potential repeal of the ability to expense intangible drilling costs having the most significant potential future impact to us. Other tax reform proposals could accelerate tangible drilling cost deductions as a replacement for interest expense deductions. Some of these changes, if enacted, could make it more costly for us to explore for and develop our natural gas resources.

The rates of federal, state and local taxes applicable to the industries in which we operate, including production taxes paid by EQT Production, often fluctuate, and could be increased by the various taxing authorities. In addition, the tax laws, rules and regulations that affect our business, such as the imposition of a new severance tax (a tax on the extraction of natural resources) in states in which we produce gas, could change. Any such increase or change could adversely impact our earnings, cash flows and financial position.

In 2010, the U.S. Congress adopted comprehensive financial reform legislation that established federal oversight and regulation of the over-the-counter derivative market and entities, such as us, that participate in that market. The legislation, known as the Dodd-Frank Act, required the CFTC, the SEC and other regulatory agencies to promulgate rules and regulations implementing the legislation. As of the filing date of this Annual Report on Form 10-K, the CFTC had adopted and implemented many final rules that impose regulatory obligations on all market participants, including us, such as recordkeeping and certain reporting obligations. Other rules that may be relevant to us or our counterparties have yet to be finalized. Because significant rules relevant to natural gas hedging activities are still at the proposal stage, it is not possible at this time to predict the extent of the impact of the regulations on our hedging program, including available counterparties, or regulatory compliance obligations. We have experienced increased, and anticipate additional, compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

Table of Contents

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all.

We and EQM rely upon access to both short-term bank and money markets and longer-term capital markets as sources of liquidity for any capital requirements not satisfied by the cash flows from operations or other sources. Future challenges in the global financial system, including access to capital markets and changes in the terms of and cost of capital, including increases in interest rates, may adversely affect our or EQM's business and financial condition. Our and EQM's ability to access the capital markets may be restricted at a time when we or EQM desire, or need, to raise capital, which could have an impact on our or EQM's flexibility to react to changing economic and business conditions or our ability to implement our business strategies. Adverse economic and market conditions could negatively affect the collectability of our trade receivables and cause our commodity hedging counterparties to be unable to perform their obligations or to seek bankruptcy protection. Future challenges in the economy could also lead to reduced demand for natural gas, NGLs and oil which could have a negative impact on our and EQM's revenues and credit ratings.

As of February 8, 2017, our long-term debt was rated “Baa3” by Moody’s Investors Services (Moody’s), “BBB” by Standard & Poor’s Ratings Service (S&P), and “BBB-” by Fitch Ratings Service (Fitch), and EQM's long-term debt was rated “Ba1” by Moody's, “BBB-” by S&P, and “BBB-” by Fitch. Although we are not aware of any current plans of Moody’s, S&P or Fitch to lower their respective ratings on our or EQM’s debt, we cannot be assured that our or EQM’s credit ratings will not be downgraded or withdrawn entirely by a rating agency. Low prices for natural gas, NGLs and oil or an increase in the level of our indebtedness in the future may result in a downgrade in the ratings that are assigned to our or EQM’s debt. If any credit rating agency downgrades the ratings, particularly below investment grade, our or EQM’s access to the capital markets may be limited, borrowing costs and margin deposits on our derivatives would increase, we may be required to provide additional credit assurances in support of pipeline capacity contracts, the amount of which may be substantial, or we or EQM may be required to provide additional credit assurances related to joint venture arrangements or construction contracts, which could adversely affect our business, results of operations and liquidity. Investment grade refers to the quality of a company’s credit as assessed by one or more credit rating agencies. In order to be considered investment grade, the Company must be rated “BBB-” or higher by S&P, “Baa3” or higher by Moody’s and “BBB-” or higher by Fitch.

The loss of key personnel could adversely affect our ability to execute our strategic, operational and financial plans.

Our operations are dependent upon key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, the success of our operations will depend, in part, on our ability to attract, develop and retain experienced personnel. There is competition within our industry for experienced technical personnel and certain other professionals, which could increase the costs associated with attracting and retaining such personnel. If we cannot attract, develop and retain our technical and professional personnel or attract additional experienced technical and professional personnel, our ability to compete could be harmed.

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

Negative public perception regarding us and/or our industry resulting from, among other things, oil spills, the explosion of natural gas transmission and gathering lines and concerns raised by advocacy groups about hydraulic fracturing and pipeline projects, may lead to increased regulatory scrutiny which may, in turn, lead to new local, state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts.

Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

Cyber incidents may adversely impact our operations.

Our business has become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications, to operate our production and midstream businesses, and the maintenance of our financial and other records has long been dependent upon such technologies. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Deliberate attacks on, or unintentional events affecting, our systems or infrastructure, the systems or infrastructure of third parties or the cloud could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery of natural gas, NGLs and oil, difficulty in completing and settling transactions, challenges in maintaining our books and records, communication interruptions, environmental damage, personal injury, property damage, other operational disruptions and third-party liability. Further, as cyber incidents continue to evolve, we

Table of Contents

may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Our failure to assess or capitalize on production opportunities could negatively impact our long-term growth prospects for our production business.

Our goal of sustaining long-term growth for our production business is contingent upon our ability to identify production opportunities based on market conditions. Our decision to drill a well is subject to a number of factors which may alter our drilling schedule or our plans to drill at all. We may have difficulty drilling all of the wells before the lease term expires which could result in the loss of certain leasehold rights, or we could drill wells in locations where we do not have the necessary infrastructure to deliver the natural gas, NGLs and oil to market. Moreover, an incorrect determination of legal title to our wells could result in liability to the owner of the natural gas or oil rights and an impairment to our assets. Successfully identifying production opportunities involves a high degree of business experience, knowledge and careful evaluation of potential opportunities, along with subjective judgments and assumptions that may prove to be incorrect. For example, seismic data is subject to interpretation and may not accurately identify the presence of natural gas or other hydrocarbons. Certain of our future drilling activities may not be successful and, if unsuccessful, this failure could adversely affect our business, results of operations or liquidity. Because we have a limited operating history in certain areas, our future operating results may be difficult to forecast, and our failure to sustain high growth rates in the future could adversely affect the market price of our common stock.

Recent natural gas, NGLs and oil price declines have resulted in impairment of certain of our non-core assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance may result in additional write-downs of the carrying amounts of our assets, which could materially and adversely affect our results of operations in future periods.

We review the carrying values of our proved oil and gas properties and midstream assets for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. The estimated future cash flows used to test our proved oil and gas properties for recoverability are based on proved and, if determined reasonable by management, risk-adjusted probable reserves, utilizing assumptions generally consistent with the assumptions utilized by the Company's management for internal planning and budgeting purposes, including, among other things, the use of the asset, anticipated production from reserves, future market prices for natural gas, NGLs and oil, future operating costs and inflation. Commodity pricing is estimated by using a combination of the five-year NYMEX forward strip prices and assumptions related to gas quality, basis and inflation. Proved oil and gas properties and midstream assets that have carrying amounts in excess of estimated future cash flows are written down to fair value, which is estimated by discounting the estimated future cash flows using discount rate assumptions that marketplace participants would use in their estimates of fair value.

Our estimate of the fair value of our assets depends on the prices of natural gas, NGLs and oil. Primarily as a result of declines in NYMEX forward strip prices, we recorded non-cash, pre-tax impairment charges of $59.7 million to certain long-lived assets during 2016 and $94.3 million and $105.2 million to our proved oil and gas properties in the non-core Permian basin during 2015 and 2014, respectively. Future declines in natural gas, NGLs or oil prices, increases in operating costs or adverse changes in well performance, among other things, may result in our having to make significant future downward adjustments to our estimated proved reserves and/or could result in additional non-cash impairment charges to write-down the carrying amount of our assets, which may have a material adverse effect on our results of operations in future periods. For example, all other things being equal, a further decline in the average five-year NYMEX forward strip price in a future period may cause the Company to recognize impairments on non-core assets, including the Company's assets in the Huron play, which had a carrying value of approximately $3 billion at December 31, 2016. See "Impairment of Oil and Gas Properties" under Item 7, "Management's Discussion and

Analysis of Financial Condition and Results of Operations."

The amount and timing of actual future natural gas, NGLs and oil production is difficult to predict and may vary significantly from our estimates, which may reduce our earnings.

Our future success depends upon our ability to develop additional gas reserves that are economically recoverable and to optimize existing well production, and our failure to do so may reduce our earnings. Our drilling and subsequent maintenance of wells can involve significant risks, including those related to timing, cost overruns and operational efficiency, and these risks can be affected by the availability of capital, leases, rigs, equipment, a qualified work force, and adequate capacity for the treatment and recycling or disposal of waste water generated in our operations, as well as weather conditions, natural gas, NGLs and oil price volatility, government approvals, title and property access problems, geology, equipment failure or accidents and other factors. Drilling for natural gas, NGLs and oil can be unprofitable, not only from dry wells, but from productive wells that do not produce sufficient revenues to return a profit. Additionally, a failure to effectively and efficiently operate existing wells may cause production volumes to fall short of our projections. Without continued successful development or acquisition activities, together with effective operation of existing wells, our reserves and revenues will decline as a result of our current reserves being depleted by production.

We also rely on third parties for certain construction, drilling and completion services, materials and supplies. Delays or failures to perform by such third parties could adversely impact our earnings, cash flows and financial position.

The standardized measure of discounted future net cash flows from our proved reserves is not the same as the current market value of our estimated natural gas, NGLs and oil reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated natural gas, NGLs and oil reserves. In accordance with SEC requirements, we based the discounted future net cash flows from our proved reserves on the twelve month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net cash flows from our properties will be affected by factors such as the actual prices we receive for natural gas, NGLs and oil, the amount, timing and cost of actual production and changes in governmental regulations or taxation. In addition, the 10% discount factor we use when calculating the standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas, NGLs and oil industry in general.

Our proved reserves are estimates that are based upon many assumptions that may prove to be inaccurate. Any significant change in these underlying assumptions will greatly affect the quantities and present value of our reserves.

Reserve engineering is a subjective process involving estimates of underground accumulations of natural gas, NGLs and oil and assumptions concerning future prices, production levels and operating and development costs, some of which are beyond our control. These estimates and assumptions are inherently imprecise, and we may adjust our estimates of proved reserves based on changes in these estimates or assumptions. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Any significant variance from our assumptions could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas, NGLs and oil, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas, NGLs and oil we ultimately recover being different from our reserve estimates.

See Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” for further discussion regarding the Company’s exposure to market risks, including the risks associated with the Company's use of derivative contracts to hedge commodity prices.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Principal facilities are owned or, in the case of certain office locations, warehouse buildings and equipment, leased, by the Company’s business segments. The majority of the Company’s properties are located on or under (i) private properties owned in fee, held by lease or occupied under perpetual easements or other rights acquired for the most part without warranty of underlying land titles or (ii) public highways under franchises or permits from various governmental authorities. The Company’s facilities are generally well maintained and, where appropriate, are replaced or expanded to meet operating requirements.

EQT Production: EQT Production’s properties are located primarily in Pennsylvania, West Virginia, Kentucky and Virginia. This segment has approximately 3.6 million gross acres (approximately 70% of which are considered undeveloped), which encompass substantially all of the Company’s acreage of proved developed and undeveloped natural gas and oil producing properties. Approximately 790,000 of these gross acres are located in the Marcellus play. Although most of its wells are drilled to relatively shallow depths (2,000 to 8,000 feet below the surface), the Company retains what are normally considered “deep rights” on the majority of its acreage. As of December 31, 2016, the Company estimated its total proved reserves to be 13.5 Tcfe, consisting of proved developed producing reserves of 6.6 Tcfe, proved developed non-producing reserves of 0.2 Tcfe and proved undeveloped reserves of 6.7 Tcfe. Substantially all of the Company’s reserves reside in continuous accumulations.

The Company’s estimate of proved natural gas, NGLs and oil reserves is prepared by Company engineers. The engineer primarily responsible for preparing the reserve report and the technical aspects of the reserves audit received a bachelor’s degree

Table of Contents

in Chemical Engineering from the Pennsylvania State University and has 19 years of experience in the oil and gas industry. To ensure that the reserves are materially accurate, management reviews the price, heat content conversion rate and cost assumptions used in the economic model to determine the reserves. Additionally, division of interest and production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems, and the reserve reconciliation between prior year reserves and current year reserves is reviewed by senior management.

The Company's estimate of proved natural gas, NGLs and oil reserves is audited by the independent consulting firm of Ryder Scott Company, L.P. (Ryder Scott), which is hired by the Company's management. Since 1937, Ryder Scott has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally. In the course of its audit, Ryder Scott reviewed 100% of the total net natural gas, NGLs and oil proved reserves attributable to the Company's interests as of December 31, 2016. Ryder Scott conducted a detailed, well by well, audit of the Company's largest properties. This audit covered 82% of the Company's proved developed reserves. Ryder Scott's audit of the remaining approximately 18% of the Company's proved developed properties consisted of an audit of aggregated groups not exceeding 200 wells per case for operated wells and 231 wells per case for non-operated wells. For undeveloped locations, the Company determined, and Ryder Scott reviewed and approved, the areas within the Company's acreage considered to be proven. For undeveloped locations, reserves were assigned and projected by the Company's reserves engineers for locations within these proven areas and approved by Ryder Scott based on analogous type curves and offset production information. Ryder Scott's audit report has been filed herewith as Exhibit 99.

No report has been filed with any federal authority or agency reflecting a 5% or more difference from the Company's estimated total reserves. Additional information relating to the Company's estimates of natural gas, NGLs and crude oil reserves and future net cash flows is provided in Note 23 (unaudited) to the Consolidated Financial Statements.

In 2016, the Company commenced drilling operations (spud or drilled) on 130 gross horizontal wells in the Marcellus and Upper Devonian plays. Total proved reserves in the Marcellus play increased 44% to 11.2 Tcfe in 2016 primarily as a result of the Company's acquisition and drilling activity. Production sales volumes in 2016 from the Marcellus, including the Upper Devonian play, was 660.1 Bcfe. Over the past five years, the Company has experienced a 98% developmental drilling success rate.

Natural gas, NGLs and crude oil pricing:

	For the Years Ended December 31,		
	2016	2015	2014
Natural Gas:			
Average sales price (excluding cash settled derivatives) ($/Mcf)	$ 1.88	$ 2.28	$ 4.19
Average sales price (including cash settled derivatives) ($/Mcf)	$ 2.41	$ 3.06	$ 4.21
NGLs (excluding ethane):			
Average sales price ($/Bbl)	$ 19.43	$ 18.84	$ 41.94
Ethane:			
Average sales price ($/Bbl) (a)	$ 5.08	$ —	$ —
Crude Oil:			
Average sales price ($/Bbl)	$ 34.73	$ 38.70	$ 78.51

(a) Ethane sales began in 2016.

For additional information on pricing, see "Consolidated Operational Data" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The Company’s average per unit production cost, excluding production taxes, of natural gas, NGLs and oil during 2016, 2015 and 2014 was $0.15 per Mcfe, $0.19 per Mcfe and $0.24 per Mcfe, respectively. At December 31, 2016, the Company had approximately 50 multiple completion wells.

Table of Contents

	Natural Gas	Oil
Total productive wells at December 31, 2016:		
Total gross productive wells	13,699	109
Total net productive wells	12,956	105
Total in-process wells at December 31, 2016:	0	
Total gross in-process wells	165	—
Total net in-process wells	161	—

Summary of proved natural gas, oil and NGL reserves as of December 31, 2016 based on average fiscal year prices:

	Natural Gas (MMcf)	Oil and NGLs (Bbls)
Developed	6,074,958	128,000
Undeveloped	6,256,909	68,090
Total proved reserves	12,331,867	196,090

Total acreage at December 31, 2016:	
Total gross productive acres	1,057,476
Total net productive acres	1,018,790
Total gross undeveloped acres	2,515,331
Total net undeveloped acres	2,248,891

As of December 31, 2016, the Company had no proved undeveloped reserves that remained undeveloped for more than five years.

As of December 31, 2016, leases associated with approximately 25,700 gross undeveloped acres expire in 2017 if they are not renewed. The Company has an active lease renewal program in areas targeted for development. Within the Marcellus formation, the Company has no requirements to drill any wells in 2017 within its lease and acquisition agreements.

Number of net productive and dry exploratory and development wells drilled:

	For the Years Ended December 31,		
	2016	2015	2014
Exploratory wells:			
Productive	—	1.0	—
Dry	—	1.0	—
Development wells:			
Productive	140.9	234.5	265.4
Dry	15.0	3.0	—

The increase in dry developmental wells in 2016 was primarily related to vertical wells that are no longer planned to be drilled horizontally due to the uncertainty of identifying a near-term pipeline solution.

Table of Contents

The table below provides select production, sales and acreage data by state (as of December 31, 2016 unless otherwise noted), which is substantially all from the Appalachian Basin. NGLs and oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods. Refer to the table on page 38 for sales volumes by final product.

	Pennsylvania	West Virginia	Kentucky	Other (b)	Total
Natural gas, oil and NGLs production (MMcfe) – 2016 (a)	426,524	272,529	61,267	16,043	776,363
Natural gas, oil and NGLs production (MMcfe) – 2015 (a)	327,616	208,376	65,726	16,968	618,686
Natural gas, oil and NGLs production (MMcfe) – 2014 (a)	237,365	164,330	66,775	19,609	488,079
Natural gas, oil and NGLs sales (MMcfe) – 2016	429,011	264,452	51,200	14,304	758,967
Natural gas, oil and NGLs sales (MMcfe) – 2015	329,626	200,121	57,825	15,510	603,082
Natural gas, oil and NGLs sales (MMcfe) – 2014	240,685	158,868	58,790	17,917	476,260
Average net revenue interest of proved reserves (%)	81.2 %	84.8 %	93.2 %	80.5 %	83.6 %
Total gross productive wells	1,212	5,213	5,720	1,663	13,808
Total net productive wells	1,198	4,961	5,409	1,493	13,061
Total gross productive acreage	115,473	334,420	471,055	136,528	1,057,476
Total gross undeveloped acreage	319,809	963,417	1,030,746	201,359	2,515,331
Total gross acreage	435,282	1,297,837	1,501,801	337,887	3,572,807
Total net productive acreage	114,540	331,381	463,902	108,967	1,018,790
Total net undeveloped acreage	295,768	816,261	956,495	180,367	2,248,891
Total net acreage	410,308	1,147,642	1,420,397	289,334	3,267,681
(Amounts in Bcfe)					
Proved developed producing reserves	2,733	2,516	1,156	166	6,571
Proved developed non-producing reserves	188	84	—	—	272
Proved undeveloped reserves	3,415	3,250	—	—	6,665
Proved developed and undeveloped reserves	6,336	5,850	1,156	166	13,508
Gross proved undeveloped drilling locations	347	361	—	—	708
Net proved undeveloped drilling locations	323	361	—	—	684

(a) All production information related to natural gas is reported net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs.

(b) Other includes Ohio, Virginia, Maryland and Texas.

The Company sells natural gas within the Appalachian Basin and in markets accessible through its transportation portfolio under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves. As of December 31, 2016, the Company's delivery commitments through 2021 were as follows:

For the Year Ended December 31, Natural Gas (Bcf)

2017	754
2018	483
2019	298
2020	217
2021	135

Capital expenditures at EQT Production totaled $2.1 billion during 2016, including $1.3 billion for the acquisition of properties. The Company invested approximately $623.1 million during 2016 developing proved reserves and approximately $160.0 million on wells still in progress at year end. During the year ended December 31, 2016, the Company converted 647 Bcfe of proved undeveloped reserves to proved developed reserves. The Company had additions to proved developed reserves of 693 Bcfe, including 320 Bcfe from acquired wells and 341 Bcfe from wells developed in 2016 that had not previously been classified as proved. The acquisition of acreage added 2,076 Bcfe of proved undeveloped reserves, which was partially offset by 389 Bcfe of economic reserves that are no longer anticipated to be drilled within 5 years of booking and 138 Bcfe of reserves associated

Table of Contents

with wells that are no longer economic as determined in accordance with SEC pricing requirements. As of December 31, 2016, the Company's proved undeveloped reserves totaled 6.7 Tcfe, 100% of which is associated with the development of the Marcellus, including Upper Devonian, play. All proved undeveloped drilling locations are expected to be drilled within five years.

The Company's 2016 extensions, discoveries and other additions totaled 2,385 Bcfe, which exceeded the 2016 production of 776 Bcfe. Of these reserves, 2,044 Bcfe are attributed to the addition of proved undeveloped locations in the Company's Pennsylvania and West Virginia Marcellus fields and 341 Bcfe are from the development of locations not previously booked as proved.

Wells located in Pennsylvania are primarily in Marcellus formations with depths ranging from 5,000 feet to 8,000 feet. Wells located in West Virginia are primarily in Marcellus and Huron formations with depths ranging from 2,500 feet to 6,500 feet. Wells located in Kentucky are primarily in Huron formations with depths ranging from 2,500 feet to 6,000 feet. Wells located in other areas are in Coalbed Methane, Utica and Permian formations with depths ranging from 2,000 feet to 13,500 feet.

As a result of the changes to the Company's reporting segments effective for this Annual Report on Form 10-K, EQT Production operations include certain non-core midstream operations, primarily supporting the Company's production operations in the Huron play. EQT Production owns or operates approximately 6,550 miles of gathering lines primarily to support its own operations in Kentucky and southern West Virginia. Substantially all of the gathering operation's transported volumes are delivered to interstate pipelines on which the Company and other customers lease capacity. These pipelines are subject to periodic curtailments for maintenance and repairs.

EQT Production owns or leases office space in Pennsylvania, West Virginia, Virginia, Kentucky and Texas.

EQT Gathering and EQT Transmission: The following table provides information regarding EQT Gathering's gathering system and EQT Transmission's transmission and storage systems as of December 31, 2016:

System	Approximate Number of Miles	Approximate Number of Receipt Points	Approximate Compression (Horsepower)
Gathering	1,800	2,250	146,000
Transmission and storage	950	150	120,000

For a description of material properties, see "EQT Gathering Business Segment" and "EQT Transmission Business Segment" under Item 1, "Business," which is incorporated herein by reference.

Headquarters: The Company's corporate headquarters and other operations are located in leased office space in Pittsburgh, Pennsylvania.

See "Capital Resources and Liquidity" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," for a discussion of capital expenditures.

Table of Contents

Item 3. Legal Proceedings

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company accrues legal and other direct costs related to loss contingencies when actually incurred. The Company has established reserves it believes to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, the Company believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the financial position, results of operations or liquidity of the Company.

Environmental Proceedings

Phoenix S Impoundment, Tioga County, Pennsylvania

In June and August 2012, the Company received three Notices of Violation (NOVs) from the Pennsylvania Department of Environmental Protection (the PADEP). The NOVs alleged violations of the Pennsylvania Oil and Gas Act and Clean Streams Law in connection with the unintentional release in May 2012, by a Company vendor, of water from an impaired water pit at a Company well location in Tioga County, Pennsylvania. Since confirming a release, the Company has cooperated with the PADEP in remediating the affected areas.

During the second quarter of 2014, the Company received a proposed consent assessment of civil penalty from the PADEP that proposed a civil penalty related to the NOVs. On September 19, 2014, the Company filed a declaratory judgment action in the Commonwealth Court of Pennsylvania against the PADEP seeking a court ruling on the PADEP’s legal interpretation of the penalty provisions of the Clean Streams Law, which interpretation the Company believed was legally flawed and unsupportable. On October 7, 2014, based on its interpretation of the penalty provisions, the PADEP filed a complaint against the Company before the Pennsylvania Environmental Hearing Board (the EHB) seeking $4.53 million in civil penalties. A hearing before the EHB was held in July 2016,and the Company expects the EHB's decision by mid-year 2017. In January 2017, the Commonwealth Court ruled in favor of the Company, finding the PADEP’s interpretation of the penalty provisions of the Clean Streams Law erroneous, and the PADEP appealed that decision to the Pennsylvania Supreme Court. While the Company expects the PADEP’s claims to result in penalties that exceed $100,000, the Company expects the resolution of this matter will not have a material impact on the financial position, results of operations or liquidity of the Company.

Allegheny Valley Connector, Cambria County, Pennsylvania

Between September 2015 and February 2016, EQM, as the operator of the AVC facilities which at that time were owned by EQT, received eight NOVs from the PADEP. The NOVs alleged violations of the Pennsylvania Clean Streams Law in connection with inadvertent releases of sediment and bentonite to water that occurred while drilling for a pipeline replacement project in Cambria County, Pennsylvania. EQT and EQM immediately addressed the releases and fully cooperated with the PADEP. In April 2016, EQM received a proposed consent assessment of civil penalty from the PADEP that proposed a civil penalty related to the NOVs. In October 2016, EQM acquired the AVC facilities from EQT, including any future obligations related to these releases. EQM and the PADEP have put their discussions regarding the proposed civil penalty on hold pending the completion of mitigation activities. While the PADEP’s claims may result in penalties that exceed $100,000, the Company expects that the resolution of this matter will not have a material impact on the financial position, results of operations or liquidity of the Company or EQM.

Trans Energy, Inc. Matter, West Virginia

As described in Note 9 to the Consolidated Financial Statements, the Company completed the acquisition of Trans Energy, Inc. (Trans Energy) on December 5, 2016. As a result, Trans Energy is now an indirect wholly owned subsidiary of EQT. Between 2009 and 2011, Trans Energy received several NOVs from the West Virginia Department of Environmental Protection (the WVDEP) as well as seven Compliance Orders from the EPA. The NOVs and Compliance Orders alleged various violations of the federal Clean Water Act related to the filling of streams and wetlands to create impoundments at several well pads in Marshall, Wetzel and Marion Counties, West Virginia.

On August 25, 2014, Trans Energy entered into a civil consent decree with the EPA (the Consent Decree) to settle the various violations of the Clean Water Act. The Consent Decree required the payment of a $3 million civil penalty. Trans Energy paid $1.25 million of the penalty prior to the Company's acquisition of Trans Energy; the remaining $1.75 million will be paid by EQT on or before April 21, 2017. The Consent Decree also requires, among other things, numerous restoration activities associated with impoundments, well pads and access roads in West Virginia at an estimated cost of $10 - $15 million.

Table of Contents

On October 1, 2014, Trans Energy pleaded guilty to three misdemeanor charges filed by the United States Attorney for the Northern District of West Virginia related to the same violations of the Clean Water Act that were the subject of the Consent Decree. In connection with this plea agreement (the Plea Agreement), Trans Energy paid a $600,000 fine and was placed on probation until April 2017.

Finally, on December 21, 2015, Trans Energy entered into an Administrative Agreement with the EPA's Office of Suspension and Debarment to resolve all matters relating to suspension, debarment and statutory disqualification arising from the Plea Agreement. The Administrative Agreement requires, among other things, Trans Energy to comply with the Plea Agreement and Consent Decree, prepare semiannual compliance reports, and retain an independent monitor to certify Trans Energy's compliance. As a result of the Company's acquisition of Trans Energy, the Company is currently working with the EPA's Office of Suspension and Debarment to agree to an amendment to, or possible termination of, the Administrative Agreement.

Other

The Company has received a number of other NOVs from environmental agencies in some of the states in which the Company operates alleging various violations of oil and gas, air, water and waste regulations. The Company has responded to these NOVs and has, where applicable, substantially corrected or remediated the activities in question. The Company disputes the facts alleged in the NOVs and cannot predict with certainty whether any or all of these NOVs will result in penalties. If penalties are imposed, an individual penalty or the aggregate of these penalties could result in monetary sanctions in excess of $100,000.

Item 4. Mine Safety Disclosures

Not Applicable.

Executive Officers of the Registrant (as of February 9, 2017)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Randall L. Crawford (54)	Senior Vice President, EQT Corporation and President, Midstream and Commercial (2003)	Elected to present position December 2013; Senior Vice President, EQT Corporation and President, Midstream, Distribution and Commercial from April 2010 to December 2013. Mr. Crawford is also Executive Vice President and Chief Operating Officer of EQT Midstream Services, LLC, the general partner of EQM, since December 2013. Mr. Crawford was Executive Vice President of EQT Midstream Services, LLC from January 2012 to December 2013 and also served as a Director of EQT Midstream Services, LLC from January 2012 to January 2017. As previously disclosed in the Company’s Form 8-K filed with the SEC on January 9, 2017, as amended on January 10, 2017, Mr. Crawford will step down as Senior Vice President and President, Midstream and Commercial of EQT Corporation and Executive Vice President and Chief Operating Officer of EQT Midstream Services, LLC effective as of February 28, 2017 at which time he will cease to be an employee of the Company.
Lewis B. Gardner (59)	General Counsel and Vice President, External Affairs (2008)	Elected to present position March 2008. Mr. Gardner is also a Director of each of EQT Midstream Services, LLC, the general partner of EQM, since January 2012, and EQT GP Services, LLC, the general partner of EQGP, since January 2015.
Robert J. McNally (46)	Senior Vice President and Chief Financial Officer (2016)	Elected to present position March 2016. Mr. McNally is also a Director and Senior Vice President and Chief Financial Officer of each of EQT Midstream Services, LLC and EQT GP Services, LLC, the general partners of EQM and EQGP, respectively, since March 2016. Prior to joining EQT Corporation, Mr. McNally served as Executive Vice President and Chief Financial Officer of Precision Drilling Corporation, a publicly traded drilling services company, from July 2010 to March 2016.
Charlene Petrelli (56)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007.
David L. Porges (59)	Chairman and Chief Executive Officer (1998)	Elected to present position December 2015; Chairman, President, and Chief Executive Officer from May 2011 to December 2015. Mr. Porges is also Chairman, President and Chief Executive Officer of each of EQT Midstream Services, LLC, the general partner of EQM, since January 2012, and EQT GP Services, LLC, the general partner of EQGP, since January 2015. As previously disclosed in the Company's Form 8-K filed with the SEC on December 13, 2016, Mr. Porges will cease to be Chief Executive Officer of the Company effective as of March 1, 2017, at which time he will become Executive Chairman of the Company. Steven T.

		Schlotterbeck will succeed Mr. Porges as Chief Executive Officer of the Company. Mr. Porges will serve as Executive Chairman through February 28, 2018. As previously disclosed in EQM's and EQGP's respective Form 8-Ks filed with the SEC on January 23, 2017, Mr. Porges will cease to be President and Chief Executive Officer of the general partners of EQM and EQGP, effective as of March 1, 2017.
Steven T. Schlotterbeck (51)	President, EQT Corporation and President, Exploration and Production (2008)	Elected to present position December 2015; Executive Vice President, EQT Corporation and President, Exploration and Production from December 2013 to December 2015; Senior Vice President, EQT Corporation and President, Exploration and Production from April 2010 to December 2013. Mr. Schlotterbeck is also a Director of EQT Corporation, since January 2017, a Director of EQT GP Services, LLC, the general partner of EQGP, since January 2015, and a Director of EQT Midstream Services, LLC, the general partner of EQM, since January 2017. As previously disclosed in the Company's Form 8-K filed with the SEC on December 13, 2016, Mr. Schlotterbeck was elected Chief Executive Officer of the Company, effective as of March 1, 2017. As previously disclosed in EQM's and EQGP's respective Form 8-Ks filed with the SEC on January 23, 2017, Mr. Schlotterbeck was also elected President and Chief Executive Officer of the general partners of EQM and EQGP, effective as of March 1, 2017.
Jimmi Sue Smith (44)	Chief Accounting Officer (2016)	Elected to present position September 2016; Vice President and Controller of the Company's midstream and commercial businesses from March 2013 to September 2016; Vice President and Controller of the Company's midstream business from January 2013 through March 2013; and Vice President and Controller of the Company's commercial group from September 2011 through January 2013. Ms. Smith is also Chief Accounting Officer of EQT Midstream Services, LLC and EQT GP Services, LLC, the general partners of EQM and EQGP, respectively, since September 2016.

All executive officers have executed agreements with the Company and serve at the pleasure of the Company’s Board of Directors. Officers are elected annually to serve during the ensuing year or until their successors are elected and qualified, or until death, resignation or removal.

Table of Contents

PART II

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

The Company’s common stock is listed on the New York Stock Exchange. The high and low sales prices reflected in the New York Stock Exchange Composite Transactions and the dividends declared and paid per share for 2016 and 2015 are summarized as follows (in U.S. dollars per share):

	2016			2015		
	High	Low	Dividend	High	Low	Dividend
1st Quarter	$68.26	$48.30	$ 0.03	$83.46	$71.33	$ 0.03
2nd Quarter	80.61	63.48	0.03	92.79	80.86	0.03
3rd Quarter	79.64	67.69	0.03	81.67	63.09	0.03
4th Quarter	75.74	63.11	0.03	77.58	47.10	0.03

As of January 31, 2017, there were 2,350 shareholders of record of the Company’s common stock.

The amount and timing of dividends is subject to the discretion of the Board of Directors and depends upon business conditions, such as the Company’s lines of business, results of operations and financial condition, strategic direction and other factors. The Board of Directors has the discretion to change the annual dividend rate at any time for any reason.

Recent Sales of Unregistered Securities

None.

Market Repurchases

The following table sets forth the Company’s repurchases of equity securities registered under Section 12 of the Securities Exchange Act of 1934, as amended, that occurred during the three months ended December 31, 2016:

Period	Total number of shares purchased (a)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs (b)
October 2016 (October 1 – October 31)	—	$ —	—	700,000
November 2016 (November 1 – November 30)	4,122	68.78	—	700,000
December 2016 (December 1 – December 31)	164	67.06	—	700,000
Total	4,286	$ 68.71	—	

(a) Reflects shares withheld by the Company to pay taxes upon vesting of restricted stock.

(b) During 2014, the Company’s Board of Directors approved a share repurchase authorization of up to 1,000,000 shares of the Company’s outstanding common stock. The Company may repurchase shares from time to time in open market or in privately negotiated transactions. The share repurchase authorization does not obligate the Company to acquire any specific number of shares, has no pre-established end date and may be discontinued by the Company at any time. As of December 31, 2016, the Company had repurchased 300,000 shares under this authorization since its inception.

Table of Contents

Stock Performance Graph

The following graph compares the most recent five-year cumulative total return attained by holders of the Company's common stock with the cumulative total returns of the S&P 500 Index and a customized peer group of 22 companies. The individual companies of the prior customized peer group (the 2015 Self-Constructed Peer Group) and the new customized peer group (the 2016 Self-Constructed Peer Group) are listed below. An investment of $100 (with reinvestment of all dividends) is assumed to have been made at the close of business on December 31, 2011 in the Company's common stock, in the S&P 500 Index and in each customized peer group. Relative performance is tracked through December 31, 2016.

	12/11	12/12	12/13	12/14	12/15	12/16
EQT Corporation	$100.00	$109.42	$166.83	$140.84	$97.14	$122.09
S&P 500	100.00	116.00	153.58	174.60	177.01	198.18
Self-Constructed Peer Group (a)	100.00	102.60	143.25	126.00	80.99	122.24
Self-Constructed Peer Group (b)	100.00	100.93	140.43	118.81	75.29	114.91

(a) The 2015 Self-Constructed Peer Group includes the following 22 companies: Cabot Oil & Gas Corp, Chesapeake Energy Corp, Cimarex Energy Co, Concho Resources Inc., CONSOL Energy Inc., Continental Resources Inc., Energen Corp, EOG Resources Inc., EXCO Resources Inc., National Fuel Gas Co, Newfield Exploration Co, Noble Energy Inc., ONEOK Inc., Pioneer Natural Resources Co, QEP Resources Inc., Range Resources Corp, SM Energy Co, Southwestern Energy Co, Spectra Energy Corp, Ultra Petroleum Corp, Whiting Petroleum Corp and Williams Companies Inc. The following companies were included in the self-constructed peer group that served as the basis for the stock performance chart in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 but have been excluded from the 2015 Self-Constructed Peer Group above: MarkWest Energy Partners, L.P. (acquired), Questar Corporation (acquired) and Quicksilver Resources, Inc. (filed for bankruptcy protection).

(b) The 2016 Self-Constructed Peer Group includes the following 22 companies: Cabot Oil & Gas Corp, Chesapeake Energy Corp, Cimarex Energy Co, Concho Resources Inc., CONSOL Energy Inc., Continental Resources Inc., Energen Corp, EOG Resources Inc., EXCO Resources Inc., Marathon Oil Corp, National Fuel Gas Co, Newfield Exploration Co, Noble Energy Inc., ONEOK Inc., Pioneer Natural Resources Co, QEP Resources Inc., Range Resources Corp, SM Energy Co,

Table of Contents

Southwestern Energy Co, Spectra Energy Corp, Ultra Petroleum Corp and Whiting Petroleum Corp. The 2016 Self-Constructed Peer Group is the peer group used for the Company's 2016 Incentive Performance Share Unit Program, which utilizes three-year total shareholder return against the peer group as one performance metric. It is also identical to the 2015 Self-Constructed Peer Group after adjusting for the removal of Williams Companies, Inc. (subject to an acquisition agreement at the time of consideration by EQT's Management Development and Compensation Committee (the Compensation Committee)) and the addition of Marathon Oil Corporation (determined by the Compensation Committee to be an appropriate peer).

Equity Compensation Plans

See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," for information relating to compensation plans under which the Company's securities are authorized for issuance.

Table of Contents

Item 6. Selected Financial Data

	As of and for the Years Ended December 31,				
	2016	2015	2014	2013	2012
	(Thousands, except per share amounts)				
Total operating revenues	$1,608,348	$2,339,762	$2,469,710	$1,862,011	$1,377,222
Amounts attributable to EQT Corporation:					
(Loss) income from continuing operations	$(452,983)	$85,171	$385,594	$298,729	$135,902
Net (loss) income	$(452,983)	$85,171	$386,965	$390,572	$183,395
Earnings per share of common stock attributable to EQT Corporation:					
Basic:					
(Loss) income from continuing operations	$(2.71)	$0.56	$2.54	$1.98	$0.91
Net (loss) income	$(2.71)	$0.56	$2.55	$2.59	$1.23
Diluted:					
(Loss) income from continuing operations	$(2.71)	$0.56	$2.53	$1.97	$0.90
Net (loss) income	$(2.71)	$0.56	$2.54	$2.57	$1.22
Total assets	$15,472,922	$13,976,172	$12,035,353	$9,765,907	$8,819,750
Long-term debt	$3,289,459	$2,793,343	$2,959,353	$2,475,370	$2,496,061
Cash dividends declared per share of common stock	$0.12	$0.12	$0.12	$0.12	$0.88

Refer to Note 2 to the Consolidated Financial Statements for a description of the Equitable Gas Transaction. Equitable Gas Company, LLC (Equitable Gas) and Equitable Homeworks, LLC (Homeworks) comprised substantially all of the Company's previously reported Distribution segment. The financial information of Equitable Gas and Homeworks is reflected as discontinued operations in this Annual Report on Form 10-K.

The Company adopted Accounting Standards Update (ASU) No. 2015-03, Interest - Imputation of Interest and ASU No. 2015-15, Interest - Imputation of Interest as of December 31, 2015, which requires an entity to present the debt issuance costs related to a recognized debt liability as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. All prior periods presented in this Annual Report on Form 10-K were recast to reflect the change in accounting principle retrospectively applied as of December 31, 2015.

See Item 1A, "Risk Factors", Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Notes 1, 2, 8 and 9 to the Consolidated Financial Statements for a discussion of matters that affect the comparability of the selected financial data as well as uncertainties that might affect the Company's future financial condition.

Table of Contents

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

You should read the following discussion and analysis of financial condition and results of operations in conjunction with the consolidated financial statements, and the notes thereto, included in Item 8 of this Annual Report on Form 10-K.

Consolidated Results of Continuing Operations

2016 EQT Highlights:

- Annual production sales volumes of 759.0 Bcfe, 26% higher than 2015
- Marcellus sales volumes of 660.1 Bcfe, 31% higher than 2015
- The Company completed two underwritten public offerings of common stock
- The Company increased its Marcellus acreage position by acquiring approximately 145,500 net Marcellus acres located primarily in northern West Virginia and southwestern Pennsylvania, including 122,100 net Marcellus acres acquired through the Statoil Acquisition, the Republic Transaction, the Trans Energy Merger and the Pennsylvania Acquisition
- EQM issued common units through its $750 million ATM program, receiving proceeds of $217.1 million
- EQM issued $500.0 million of 4.125% Senior Notes due December 1, 2026

Net loss from continuing operations attributable to EQT Corporation for 2016 was $453.0 million, a loss of $2.71 per diluted share, compared with income from continuing operations attributable to EQT Corporation of $85.2 million, $0.56 per diluted share, in 2015. The $538.2 million decrease in income from continuing operations attributable to EQT Corporation was primarily attributable to a loss on derivatives not designated as hedges, a 20% decrease in the average realized price, higher operating expenses and higher net income attributable to noncontrolling interests of EQM and EQGP, partially offset by a 26% increase in production sales volumes and lower income tax expense.

EQT Production received $279.4 million and $172.1 million of net cash settlements for derivatives not designated as hedges for the years ended December 31, 2016 and 2015, respectively, that are included in the average realized price but are not in GAAP operating revenues.

During the year ended December 31, 2016, the Company recorded an impairment of long-lived assets of approximately $59.7 million related to certain gathering assets sold to EQM in October 2016. The impairment was a result of a reduction in estimated future cash flows caused by the low commodity price environment and the related reduced producer drilling activity and throughput. This impairment is reflected in unallocated expenses and not recorded on any operating segment.

Income from continuing operations attributable to EQT Corporation for 2015 was $85.2 million, $0.56 per diluted share, compared with $385.6 million, $2.53 per diluted share, in 2014. The $300.4 million decrease in income from continuing operations attributable to EQT Corporation was primarily attributable to a 31% decrease in the average realized price, higher operating expenses, higher net income attributable to noncontrolling interests of EQM and EQGP and a gain on sale / exchange of assets in 2014, partially offset by a 27% increase in production sales volumes, increased gains on derivatives not designated as hedges and lower income tax expense.

EQT Production received $172.1 million and $34.2 million of net cash settlements for derivatives not designated as hedges for the years ended December 31, 2015 and 2014, respectively. These net cash settlements are included in the average realized price but are not in GAAP operating revenues.

See “Business Segment Results of Operations” for a discussion of items impacting operating income and “Other Income Statement Items” for a discussion of other income, interest expense, income taxes, income from discontinued operations and net income attributable to noncontrolling interests, and “Investing Activities” under the caption “Capital Resources and Liquidity” for a discussion of capital expenditures.

Consolidated Operational Data

The following table presents detailed natural gas and liquids operational information to assist in the understanding of the Company’s consolidated operations, including the calculation of the Company's average realized price ($/Mcfe), which is based on EQT Production adjusted operating revenues, a non-GAAP supplemental financial measure. EQT Production adjusted operating revenues is presented because it is an important measure used by the Company’s management to evaluate period-to-period comparisons of earnings trends. EQT Production adjusted operating revenues should not be considered as an alternative to EQT Corporation total operating revenues as reported in the Statements of Consolidated Operations, the most directly comparable

Table of Contents

GAAP financial measure. See “Reconciliation of Non-GAAP Financial Measures” for a reconciliation of EQT Production adjusted operating revenues to EQT Corporation total operating revenues.

	Years Ended December 31,		
in thousands (unless noted)	2016	2015	2014
NATURAL GAS			
Sales volume (MMcf)	683,495	547,094	432,980
NYMEX price ($/MMBtu) (a)	$2.47	$2.66	$4.38
Btu uplift	$0.22	$0.25	$0.38
Natural gas price ($/Mcf)	$2.69	$2.91	$4.76
Basis ($/Mcf) (b)	(0.81)	(0.63)	(0.57)
Cash settled basis swaps (not designated as hedges) ($/Mcf)	$0.09	$0.03	$0.05
Average differential, including cash settled basis swaps ($/Mcf)	$(0.72)	$(0.60)	$(0.52)
Average adjusted price ($/Mcf)	$1.97	$2.31	$4.24
Cash settled derivatives (cash flow hedges) ($/Mcf)	0.13	0.47	(0.06)
Cash settled derivatives (not designated as hedges) ($/Mcf)	0.31	0.28	0.03
Average natural gas price, including cash settled derivatives ($/Mcf)	$2.41	$3.06	$4.21
Natural gas sales, including cash settled derivatives	$1,649,831	$1,671,562	$1,822,914
LIQUIDS			
NGLs (excluding ethane):			
Sales volume (MMcfe) (c)	57,243	51,530	40,587
Sales volume (Mbbls)	9,540	8,588	6,764
Price ($/Bbl)	$19.43	$18.84	$41.94
NGLs sales	$185,405	$161,775	$283,728
Ethane:			
Sales volume (MMcfe) (c)	13,856	—	—
Sales volume (Mbbls)	2,309	—	—
Price ($/Bbl)	$5.08	$—	$—
Ethane sales	$11,742	$—	$—
Oil:			
Sales volume (MMcfe) (c)	4,373	4,458	2,693
Sales volume (Mbbls)	729	743	449
Price ($/Bbl)	$34.73	$38.70	$78.51
Oil sales	$25,312	$28,752	$35,232
Total liquids sales volume (MMcfe) (c)	75,472	55,988	43,280
Total liquids sales volume (Mbbls)	12,578	9,331	7,213
Liquids sales	$222,459	$190,527	$318,960
TOTAL PRODUCTION			
Total natural gas & liquids sales, including cash settled derivatives (d)	$1,872,290	$1,862,089	$2,141,874
Total sales volume (MMcfe)	758,967	603,082	476,260
Average realized price ($/Mcfe)	$2.47	$3.09	$4.50

(a) The Company's volume weighted NYMEX natural gas price (actual average NYMEX natural gas price ($/MMBtu) was $2.46, $2.66 and $4.41 for the years ended December 31, 2016, 2015 and 2014, respectively).

(b) Basis represents the difference between the ultimate sales price for natural gas and the NYMEX natural gas price.

(c) NGLs, ethane and crude oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods.

(d) Also referred to in this report as EQT Production adjusted operating revenues, a non-GAAP supplemental financial measure.

Table of Contents

Reconciliation of Non-GAAP Measures

The table below reconciles EQT Production adjusted operating revenues, a non-GAAP supplemental financial measure, to EQT Corporation total operating revenues as reported in the Statements of Consolidated Operations, its most directly comparable financial measure calculated in accordance with GAAP.

EQT Production adjusted operating revenues (also referred to as total natural gas & liquids sales, including cash settled derivatives) is presented because it is an important measure used by the Company's management to evaluate period-over-period comparisons of earnings trends. EQT Production adjusted operating revenues as presented excludes the revenue impact of changes in the fair value of derivative instruments prior to settlement and the revenue impact of certain pipeline and net marketing services. Management utilizes EQT Production adjusted operating revenues to evaluate earnings trends because the measure reflects only the impact of settled derivative contracts and thus does not impact the revenue from natural gas sales with the often volatile fluctuations in the fair value of derivatives prior to settlement. EQT Production adjusted operating revenues also excludes "Pipeline and net marketing services" because management considers these revenues to be unrelated to the revenues for its natural gas and liquids production. "Pipeline and net marketing services" primarily includes revenues for gathering services provided to third-parties as well as both the cost of and recoveries on third-party pipeline capacity not used for EQT Production sales volumes. Management further believes that EQT Production adjusted operating revenues as presented provides useful information to investors for evaluating period-over-period earnings trends.

Calculation of EQT Production adjusted operating revenues	Years Ended December 31,		
$ in thousands (unless noted)	2016	2015	2014
EQT Production total operating revenues	$1,387,054	$2,131,664	$2,285,138
(Deduct) add back:			
Gain for hedging ineffectiveness	—	—	(24,774)
Loss (gain) on derivatives not designated as hedges	248,991	(385,762)	(80,942)
Net cash settlements received on derivatives not designated as hedges	279,425	172,093	34,239
Premiums paid for derivatives that settled during the year	(2,132)	(364)	—
Pipeline and net marketing services	(41,048)	(55,542)	(71,787)
EQT Production adjusted operating revenues, a non-GAAP financial measure	$1,872,290	$1,862,089	$2,141,874
Total sales volumes (MMcfe)	758,967	603,082	476,260
Average realized price ($/Mcfe)	$2.47	$3.09	$4.50
EQT Production total operating revenues	$1,387,054	$2,131,664	$2,285,138
EQT Gathering total operating revenues	397,494	335,105	233,945
EQT Transmission total operating revenues	338,120	297,831	255,273
Less: intersegment revenues, net	(514,320)	(424,838)	(304,646)
EQT Corporation total operating revenues, as reported in accordance with GAAP	$1,608,348	$2,339,762	$2,469,710

Table of Contents

Business Segment Results of Operations

Business segment operating results from continuing operations are presented in the segment discussions and financial tables on the following pages. Operating segments are evaluated on their contribution to the Company's consolidated results based on operating income. Other income, interest and income taxes are managed on a consolidated basis. Headquarters' costs are billed to the operating segments based upon a fixed allocation of the headquarters' annual operating budget. Unallocated expenses consist primarily of incentive compensation and administrative costs. In 2016, unallocated expenses also included impairment of long-lived assets of approximately $59.7 million related to certain gathering assets sold to EQM in October 2016. This impairment was recorded by EQT Midstream prior to the sale and change in segments discussed below and does not relate to any of the recast segments.

The Company has reported the components of each segment's operating income from continuing operations and various operational measures in the sections below, and where appropriate, has provided information describing how a measure was derived. EQT's management believes that presentation of this information provides useful information to management and investors regarding the financial condition, operations and trends of each of EQT's business segments without being obscured by the financial condition, operations and trends for the other segments or by the effects of corporate allocations of interest, income taxes and other income. In addition, management uses these measures for budget planning purposes. The Company has reconciled each segment's operating income to the Company's consolidated operating income and net income in Note 5 to the Consolidated Financial Statements.

Prior to the October 2016 Sale, the Company reported its results of operations through two business segments: EQT Production and EQT Midstream. EQT Midstream included the Company's gathering, transmission and storage businesses as well as the Company's marketing operations that were conducted for the benefit of third-parties. Marketing operations for the benefit of EQT Production were reported in the EQT Production segment. These reporting segments reflected the Company's lines of business and were reported in the same manner in which the Company evaluated its operating performance through September 30, 2016. Following the October 2016 Sale, the Company adjusted its internal reporting structure to align with EQM's operations. These adjustments included transferring to EQT Production (i) the operation of all midstream assets not owned by EQM and (ii) marketing operations conducted for the benefit of third-parties and resulted in changes to the Company's reporting segments effective for this Annual Report on Form 10-K. Under the new reporting structure, the EQT Production segment now includes the Company's production activities, all of the Company's marketing operations and certain non-core midstream operations primarily supporting the Company's production activities. The EQT Gathering segment contains the Company's gathering assets that are included in EQM. The EQT Transmission segment includes the Company's FERC-regulated interstate pipeline and storage operations. The EQT Gathering and EQT Transmission segments are composed entirely of EQM's operations and no EQM activities are included within the EQT Production segment. Therefore, the financial and operational disclosures related to EQT Gathering and EQT Transmission in this Annual Report on Form 10-K are the same as EQM's disclosures in its Annual Report on Form 10-K for the year ended December 31, 2016. The segment disclosures and discussions contained within this Report have been recast to reflect the current reporting structure for all periods presented.

Table of Contents

EQT Production

Results of Operations

	Years Ended December 31,				
	2016	2015	% change 2016 - 2015	2014	% change 2015 - 2014
OPERATIONAL DATA					
Sales volume detail (MMcfe):					
Marcellus (a)	660,146	505,102	30.7	378,195	33.6
Other (b)	98,821	97,980	0.9	98,065	(0.1)
Total production sales volumes (c)	758,967	603,082	25.8	476,260	26.6
Average daily sales volumes (MMcfe/d)	2,074	1,652	25.5	1,305	26.6
Average realized price ($/Mcfe)	$2.47	$ 3.09	(20.1)	$ 4.50	(31.3)
Gathering to EQT Gathering ($/Mcfe)	$0.48	$ 0.51	(5.9)	$ 0.44	15.9
Transmission to EQT Transmission ($/Mcfe)	$0.20	$ 0.20	—	$ 0.20	—
Third-party gathering and transmission ($/Mcfe)	$0.32	$ 0.29	10.3	$ 0.29	—
Processing ($/Mcfe)	$0.16	$ 0.17	(5.9)	$ 0.14	21.4
Lease operating expenses (LOE), excluding production taxes ($/Mcfe)	$0.15	$ 0.19	(21.1)	$ 0.24	(20.8)
Production taxes ($/Mcfe)	$0.08	$ 0.10	(20.0)	$ 0.16	(37.5)
Production depletion ($/Mcfe)	$1.06	$ 1.18	(10.2)	$ 1.22	(3.3)

Depreciation, depletion and amortization (DD&A) (thousands):