EQT Corp
Form 10-K
February 09, 2017
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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.

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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.

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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.

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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

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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.

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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.

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- 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.

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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.

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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.

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- 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

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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.

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Transmission and Storage System

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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.

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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.

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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.

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

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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.

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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.

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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,

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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

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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.

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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

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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

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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.

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	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.

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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

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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.

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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.

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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.

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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.

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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.

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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,

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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.

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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.

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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

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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.

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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

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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.

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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):					
Production depletion	$803,883	$713,651	12.6	$582,624	22.5
Other DD&A	55,135	51,647	6.8	47,491	8.8
Total DD&A	$859,018	$765,298	12.2	$630,115	21.5
Capital expenditures (thousands) (d)	$2,073,907	$1,893,750	9.5	$2,505,365	(24.4)
FINANCIAL DATA (thousands)					
Revenues:					
Sales of natural gas, oil and NGLs	$1,594,997	$1,690,360	(5.6)	$2,107,635	(19.8)
Pipeline and net marketing services	41,048	55,542	(26.1)	71,787	(22.6)
Gain for hedging ineffectiveness	—	—	—	24,774	(100.0)
(Loss) gain on derivatives not designated as hedges	(248,991)	385,762	(164.5)	80,942	376.6
Total operating revenues	1,387,054	2,131,664	(34.9)	2,285,138	(6.7)
Operating expenses:					
Gathering	413,758	330,562	25.2	232,295	42.3
Transmission	341,569	268,368	27.3	209,967	27.8
Processing	124,864	100,329	24.5	64,313	56.0

Lease operating expenses (LOE), excluding production taxes	112,509	116,527	(3.4)	112,591	3.5
Production taxes	62,317	61,408	1.5	74,652	(17.7)
Exploration	13,410	61,970	(78.4)	21,665	186.0
Selling, general and administrative (SG&A)	180,426	172,725	4.5	149,429	15.6
DD&A	859,018	765,298	12.2	630,115	21.5
Impairment of long-lived assets	6,939	122,469	(94.3)	267,339	(54.2)
Total operating expenses	2,114,810	1,999,656	5.8	1,762,366	13.5
Gain on sale / exchange of assets	8,025	—	100.0	34,146	(100.0)
Operating (loss) income	$(719,731)	$132,008	(645.2)	$556,918	(76.3)

(a) Includes Upper Devonian wells.

(b) Includes 14,612 MMcfe and 4,173 MMcfe of Utica sales volume for the years ended December 31, 2016 and 2015, respectively.

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

(d) Includes cash capital expenditures of $1,051.2 million and non-cash capital expenditures of $87.6 million related to the Statoil Acquisition, Republic Transaction, Trans Energy Merger and the Pennsylvania Acquisition during the year ended December 31, 2016. Includes $167.3 million of cash capital expenditures and $349.2 million of non-cash capital expenditures for the exchange of assets with Range Resources Corporation (Range Resources) during the year ended December 31, 2014. See Notes 8 and 9 to the Consolidated Financial Statements for additional information related to these transactions.

Year Ended December 31, 2016 vs. December 31, 2015

EQT Production's operating loss totaled $719.7 million for 2016 compared to operating income of $132.0 million for 2015. The $851.7 million decrease in operating income was primarily due to a loss on derivatives not designated as hedges in 2016 compared to gains on derivatives not designated as hedges in 2015, a lower average realized price, increased operating expenses and decreased pipeline and net marketing services partly offset by increased sales volumes of produced natural gas and NGLs.

Total operating revenues were $1,387.1 million for 2016 compared to $2,131.7 million for 2015. Sales of natural gas, oil and NGLs decreased as a result of a lower average realized price, partly offset by a 26% increase in production sales volumes in 2016. 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. Changes in fair market value of derivative instruments prior to settlement are recognized in gain (loss) on derivatives not designated as hedges. The increase in production sales volumes was primarily the result of increased production from the 2014 and 2015 drilling programs, primarily in the Marcellus play, partially offset by the normal production decline in the Company's producing wells.

The $0.62 per Mcfe decrease in the average realized price for the year ended December 31, 2016 was primarily due to the decrease in the average NYMEX natural gas price net of cash settled derivatives of $0.53 per Mcf and a decrease in the average natural gas differential of $0.12 per Mcf. The decrease in the average differential primarily related to lower basis partly offset by favorable cash settled basis swaps. While Appalachian Basin basis improved slightly for the year ended December 31, 2016 compared to the year ended December 31, 2015, basis in the United States Northeast was significantly lower, particularly in the first quarter of 2016 compared to the first quarter of 2015, due to reduced demand attributable to warmer than normal weather conditions. Additionally, the impact of changes in natural gas prices on physical basis sales contracts and fixed price sales contracts reduced basis year over year. The Company started flowing EQT Production's produced volumes to its Rockies Express pipeline capacity and Texas Eastern Transmission Gulf Markets pipeline capacity in the fourth quarter of 2016, which resulted in a favorable impact to basis in 2016.

Pipeline and net marketing services primarily includes gathering revenues for gathering services provided to third-parties and both the cost of and recoveries on third-party pipeline capacity not used to transport the Company's produced volumes. The $14.5 million decrease in these revenues primarily related to reduced spreads on the Company's Tennessee Gas Pipeline capacity.

EQT Production total operating revenues for the year ended December 31, 2016 included a $249.0 million loss on derivatives not designated as hedges compared to a $385.8 million gain on derivatives not designated as hedges for the year ended December 31, 2015. The losses for the year ended December 31, 2016 primarily related to unfavorable changes in the fair market value of EQT Production's NYMEX swaps, partly offset by favorable changes in the fair market value of its basis swaps. During the year ended December 31, 2016, forward NYMEX prices increased while basis prices decreased.

Operating expenses totaled $2,114.8 million for 2016 compared to $1,999.7 million for 2015. The increase in operating expenses primarily resulted from increases in DD&A, gathering, transmission and processing, partly offset by reductions in non-cash impairments of long-lived assets and exploration expense. Gathering expense increased by $56.1 million due to increased affiliate firm capacity and volumetric charges and by $27.1 million due to increased third-party volumetric charges. Transmission expense increased by $39.9 million related to increased third-party costs incurred to move EQT Production's natural gas out of the Appalachian Basin and by $33.3 million primarily due to increased affiliate firm capacity charges. Processing expenses increased $24.5 million due to increased production volumes.

The decrease in LOE was primarily due to a $3.4 million decrease in salt water disposal costs as a result of increased recycling in the Marcellus Shale and certain operational cost savings in the Huron operations, partly offset by $1.8 million of costs related to the consolidation of the Company’s Huron operations. Production taxes were essentially flat as a higher Pennsylvania impact fee and severance tax settlement were offset by lower unhedged sales prices, a favorable property tax settlement and the expiration of the West Virginia volume based tax in 2016. The state of West Virginia previously imposed a $0.047 per Mcf additional volume based severance tax that was terminated on July 1, 2016.

Exploration expense decreased primarily due to a $28.6 million decrease in lease expirations related to acreage that the Company does not intend to drill prior to expiration and expenses related to exploratory wells in 2015. SG&A expense increased $7.7 million due to an increase in litigation costs of $10.4 million, a $9.4 million charge related to the termination of the EQT Corporation Retirement Plan for Employees incurred in 2016, a $5.7 million increase to the reserve for uncollectible accounts, $2.6 million of non-recurring costs related to the consolidation of the Company’s Huron operations and acquisition related expenses in 2016. These increases were partly offset by $11.2 million for drilling program reduction charges in the Permian and Huron Basins in 2015, $4.5 million of decreased personnel costs, $3.2 million of decreased professional service costs and $1.9 million of charges to write off expired right of ways options in 2015. The increase in depletion expense within DD&A expense was the result of higher produced volumes partly offset by a lower overall depletion rate in 2016. Depreciation expense within DD&A increased as a result of additional assets in service.

Impairment of long-lived assets decreased $115.5 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The 2016 impairment charge of $6.9 million primarily consisted of lease impairments on acreage that the Company did not intend to drill prior to expiration. The 2015 impairment charge consisted of impairments of proved properties in the Permian Basin of Texas of $94.3 million and impairments of proved properties in the Utica Shale of Ohio of $4.3 million, as well as unproved property impairments of $19.7 million and a $4.2 million impairment of field level NGLs processing equipment that was not being used. The proved properties impairments in 2015 were a result of continued declines in commodity prices and insufficient recovery of hydrocarbons to support continued development. The 2016 and 2015 impairments related to the unproved properties resulted from operational decisions to focus near-term development activities in the Company's Marcellus, Upper Devonian and Utica acreage.

During the fourth quarter of 2016, EQT Production sold a gathering system that primarily gathered gas for third-parties for $75.0 million. In conjunction with this transaction, the Company realized a pre-tax gain of $8.0 million, which is included in gain on sale / exchange of assets in the Statements of Consolidated Operations.

Year Ended December 31, 2015 vs. December 31, 2014

EQT Production’s operating income totaled $132.0 million for 2015 compared to $556.9 million for 2014. The $424.9 million decrease in operating income was primarily due to a lower average realized price and increased operating expenses partly offset by increased sales volumes of produced natural gas and NGLs and increased gains on derivatives not designated as hedges.

Total operating revenues were $2,131.7 million for 2015 compared to $2,285.1 million for 2014. Sales of natural gas, oil and NGLs decreased as a result of a lower average realized price, partly offset by a 27% increase in production sales volumes in 2015. 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 that are included in the average realized price but are not in GAAP operating revenues. Changes in fair market value of derivative instruments prior to settlement are recognized in gain (loss) on derivatives not designated as hedges. The increase in production sales volumes was primarily the result of increased production from the 2013 and 2014 drilling programs, primarily in the Marcellus play. This increase was partially offset by the normal production decline in the Company’s producing wells.

The $1.41 per Mcfe decrease in the average realized price for the year ended December 31, 2015 was primarily due to the decrease in the average NYMEX natural gas price net of cash settled derivatives of $1.07 per Mcf, lower NGLs prices and a decrease in the average natural gas differential of $0.08 per Mcf. The decrease in the average differential primarily related to decreased basis in the Appalachian Basin and the United States northeast that was partly offset by the impact of changes in natural gas prices on fixed price sales contracts.

The $16.2 million decrease in pipeline and net marketing services primarily related to costs, net of recoveries, of $15.3 million for the Company’s Rockies Express Pipeline capacity contract that started in the third quarter of 2015 and other decreased net marketing activity, including lower revenues on NGLs marketed for non-affiliate producers.

EQT Production total operating revenues for the year ended December 31, 2015 included a $385.8 million gain on derivatives not designated as hedges compared to an $80.9 million gain on derivatives not designated as hedges for the year ended December 31, 2014. The increased gains for the year ended December 31, 2015 primarily related to favorable changes in the fair market value of EQT Production's NYMEX swaps due to a decrease in forward NYMEX prices during the year ended December 31, 2015. For the year ended December 31, 2014, EQT Production total operating revenues also included a $24.8 million gain for hedging ineffectiveness. The Company discontinued hedge accounting in 2015.

Operating expenses totaled $1,999.7 million for 2015 compared to $1,762.4 million for 2014. The increase in operating expenses was the result of increases in DD&A, gathering, transmission, exploration, processing and SG&A expenses, partly offset by decreases in non-cash impairments of long-lived assets and production taxes. Gathering expense increased by $96.0 million due to increased affiliate firm capacity and volumetric charges and by $2.3 million due to increased third-party volumetric charges. Transmission expense increased by $35.5 million due to increased third-party costs incurred to move EQT Production's natural gas out of the Appalachian Basin and by $22.9 million due to increased affiliate firm capacity charges. Processing expense increased by $36.0 million due to increased production volumes. Production taxes decreased primarily due to a $16.7 million decrease in severance taxes due to lower market sales prices, partly offset by higher production sales volumes in certain jurisdictions subject

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to these taxes and a $4.8 million increase in property taxes. Production taxes also decreased due to a $1.4 million decrease in the Pennsylvania impact fee, primarily as a result of a decrease in the number of wells drilled in Pennsylvania in 2015. Exploration expense increased $40.3 million due to increased lease expirations of acreage that the Company did not intend to drill prior to expiration totaling $22.8 million and expenses related to exploratory wells. The increase in SG&A expense was primarily due to higher personnel costs of $17.6 million, $11.2 million of drilling program reduction charges, including rig release penalties and $1.9 million of charges to write off expired right of ways options, partly offset by $3.8 million of higher litigation and environmental remediation costs in 2014 and a $1.9 million reduction to the reserve for uncollectible accounts. The increase in depletion expense within DD&A was the result of higher produced volumes partly offset by a lower overall depletion rate in 2015. Depreciation expense within DD&A increased as a result of additional assets in service.

Operating expenses included non-cash impairment charges of $122.5 million in 2015 and $267.3 million in 2014. The 2015 impairment charge consisted of (i) impairments of proved properties in the Permian Basin of Texas of $94.3 million and in the Utica Shale of Ohio of $4.3 million, (ii) unproved property impairments of $19.7 million and (iii) a $4.2 million impairment of field level NGLs processing equipment that was not being used in operations. The 2014 impairment charge consisted of impairments of proved properties in the Permian Basin of Texas of $105.2 million and in the Utica Shale of Ohio of $75.5 million, as well as impairments of $86.6 million associated with undeveloped properties. The proved properties impairments in 2015 and 2014 were a result of declines in commodity prices and insufficient recovery of hydrocarbons to support continued development. The 2015 and 2014 impairments related to the unproved properties resulted from operational decisions to focus near-term development activities in the Company's Marcellus and Utica acreage.

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EQT Gathering

Results of Operations

	Years Ended December 31,				
	2016	2015	% change 2016 - 2015	2014	% change 2015 - 2014
FINANCIAL DATA		(Thousands, other than per day amounts)			
Firm reservation fee revenues	$339,237	$267,517	26.8	$37,449	614.4
Volumetric based fee revenues:					
Usage fees under firm contracts (a)	38,408	33,021	16.3	44,594	(26.0)
Usage fees under interruptible contracts	19,849	34,567	(42.6)	151,902	(77.2)
Total volumetric based fee revenues	58,257	67,588	(13.8)	196,496	(65.6)
Total operating revenues	397,494	335,105	18.6	233,945	43.2
Operating expenses:					
Operating and maintenance	38,367	37,011	3.7	31,576	17.2
Selling, general and administrative	39,678	30,477	30.2	30,966	(1.6)
Depreciation and amortization	30,422	24,360	24.9	23,977	1.6
Total operating expenses	108,467	91,848	18.1	86,519	6.2
Operating income	$289,027	$243,257	18.8	$147,426	65.0
OPERATIONAL DATA					
Gathered volumes (BBtu per day):					
Firm capacity reservation	1,553	1,140	36.2	180	533.3
Volumetric based services (b)	420	485	(13.4)	1,063	(54.4)
Total gathered volumes	1,973	1,625	21.4	1,243	30.7
Capital expenditures	$295,315	$225,537	30.9	$253,638	(11.1)

(a) Includes fees on volumes gathered in excess of firm contracted capacity.

(b) Includes volumes gathered under interruptible contracts and volumes gathered in excess of firm contracted capacity.

Year Ended December 31, 2016 vs. December 31, 2015

Gathering revenues increased by $62.4 million primarily as a result of higher affiliate and third party volumes gathered in 2016 compared to 2015, driven by production development in the Marcellus Shale. EQT Gathering increased firm reservation fee revenues in 2016 compared to 2015 as a result of affiliates and third parties contracting for additional capacity under firm contracts, which resulted in increased firm gathering capacity of approximately 300 MMcf per day following the completion of the NWV and Jupiter expansion projects in the fourth quarter of 2015. The decrease in usage fees under interruptible contracts was primarily due to these additional contracts for firm capacity.

Operating expenses increased by $16.6 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. Selling, general and administrative expenses increased as a result of higher allocations and personnel costs from EQT. The increase in depreciation and amortization expense resulted from additional assets placed in-service including those associated with the NWV Gathering and Jupiter expansion projects (defined in Note 4 to the Consolidated Financial Statements).

Year Ended December 31, 2015 vs. December 31, 2014

Gathering revenues increased by $101.2 million primarily as a result of higher affiliate volumes gathered driven by production development in the Marcellus Shale. EQT Gathering significantly increased firm reservation fee revenues in 2015 compared to 2014 as a result of increased capacity under firm contracts with affiliates. The decrease in usage fees was primarily due to affiliates contracting for additional firm capacity.

Operating expenses increased by $5.3 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. Operating and maintenance expense increased as a result of higher allocations, including personnel costs, from EQT of $2.7 million and higher repairs and maintenance expenses associated with increased throughput.

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EQT Transmission

Results of Operations

	Years Ended December 31,				
	2016	2015	% change 2016 – 2015	2014	% change 2015 - 2014
FINANCIAL DATA		(Thousands, other than per day amounts)			
Firm reservation revenues	$277,816	$247,231	12.4	$202,112	22.3
Volumetric based fee revenues:					
Usage fees under firm contracts[(a)]	45,679	42,646	7.1	41,828	2.0
Usage fees under interruptible contracts	14,625	7,954	83.9	11,333	(29.8)
Total volumetric based fee revenues	60,304	50,600	19.2	53,161	(4.8)
Total operating revenues	338,120	297,831	13.5	255,273	16.7
Operating expenses:					
Operating and maintenance	34,846	33,092	5.3	24,837	33.2
Selling, general and administrative	33,083	31,425	5.3	20,183	55.7
Depreciation and amortization	32,269	25,535	26.4	25,084	1.8
Total operating expenses	100,198	90,052	11.3	70,104	28.5
Operating income	$237,922	$207,779	14.5	$185,169	12.2
OPERATIONAL DATA					
Transmission pipeline throughput (BBtu per day)					
Firm capacity reservation	1,651	1,841	(10.3)	1,405	31.0
Volumetric based services[(b)]	430	281	53.0	389	(27.8)
Total transmission pipeline throughput	2,081	2,122	(1.9)	1,794	18.3
Average contracted firm transmission reservation commitments (BBtu per day)	2,814	2,624	7.2	2,056	27.6
Capital expenditures	$292,049	$203,706	43.4	$137,317	48.3

(a) Includes commodity charges and fees on volumes transported in excess of firm contracted capacity.

(b) Includes volumes transported under interruptible contracts and volumes transported in excess of firm contracted capacity.

Year Ended December 31, 2016 vs. December 31, 2015

Transmission and storage revenues increased by $40.3 million. Firm reservation revenues increased due to affiliates contracting for additional capacity under firm contracts, primarily on the OVC, as well as higher contractual rates on existing contracts in the current year. Higher usage fees under firm contracts were driven by an increase in affiliate volumes in excess of firm capacity associated with increased production development in the Marcellus Shale, partly offset by lower usage fees from third party producers which is reflected in reduced firm capacity reservation throughput for the year ended December 31, 2016 compared to the year ended December 31, 2015. These volumes also decreased as a result of warmer weather in the first quarter of 2016. This decrease in transported volumes did not have a significant impact on firm reservation fee revenues. Usage fees under interruptible contracts for the year ended December 31, 2016 increased as a result of higher third party volumes transported or stored on an interruptible basis.

Operating expenses increased by $10.1 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The increase in operating and maintenance expense resulted primarily from higher repairs and maintenance expenses associated with increased throughput. Selling, general and administrative expenses increased primarily as a result of higher allocations and personnel costs from EQT. The increase in depreciation and amortization expense was primarily a result of higher depreciation on the increased investment in transmission infrastructure, including those associated with the OVC and the AVC facilities.

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Year Ended December 31, 2015 vs. December 31, 2014

Transmission and storage revenues increased by $42.6 million reflecting production development in the Marcellus Shale by affiliate and third party producers. The increase primarily resulted from higher firm reservation fees of $45.1 million partly offset by lower usage fees under interruptible contracts. The decrease in usage fees was primarily due to customers contracting for additional firm capacity.

Operating expenses increased $19.9 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. The increase in operating and maintenance expense resulted from higher repairs and maintenance expenses of $4.3 million associated with increased throughput, higher property taxes of $2.3 million and higher allocations, including personnel costs, from EQT. Selling, general and administrative expense increased primarily as a result of higher allocations and personnel costs from EQT.

Other Income Statement Items

Other Income

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Other income	$ 31,693	$ 9,953	$ 6,853

For the years ended December 31, 2016 and 2015, the Company recorded equity in earnings of nonconsolidated investments of $9.9 million and $2.6 million, respectively, related to EQM's portion of the MVP Joint Venture's AFUDC on the MVP project. For the year ended December 31, 2014, the Company recorded equity in earnings of nonconsolidated investments of $3.4 million related to the Company's prior investment in Nora Gathering, LLC (Nora LLC). In connection with the asset exchange with Range Resources in 2014, the Company transferred its 50% ownership interest in Nora LLC to Range Resources. See Note 8 to the Consolidated Financial Statements.

For the years ended December 31, 2016, 2015 and 2014, the Company recorded AFUDC of $19.4 million, $6.3 million and $3.2 million, respectively. The increases in AFUDC were mainly attributable to increased spending on the OVC project.

Interest Expense

	Years Ended December 31,		
	2016	2015	2014
		(Thousands)	
Interest expense	$ 147,920	$ 146,531	$ 136,537

Interest expense increased $1.4 million in 2016 compared to 2015. Decreased capitalized interest of $13.3 million and additional interest expense of approximately $3.3 million related to EQM's $500 million 4.125% senior notes issued during the fourth quarter of 2016 were mostly offset by higher interest income earned on short-term investments of $6.7 million, lower interest expense resulting from the Company's repayment of $160.0 million of debt that matured in the fourth quarter of 2015, and lower EQM revolver fees.

Interest expense increased $10.0 million in 2015 compared to 2014, primarily as a result of additional interest expense of approximately $11.7 million related to EQM's 4.00% senior notes due 2024 in the aggregate principal amount of $500.0 million issued during the third quarter of 2014, partially offset by lower interest expense resulting from the Company's repayment of $150.0 million of 5.00% senior notes and $10.0 million of 7.55% Series B notes, both of which matured in the fourth quarter of 2015.

The weighted average annual interest rates on the Company's long-term debt, excluding EQM's long-term debt, was 6.5%, 6.5%, and 6.4% for 2016, 2015 and 2014, respectively. The weighted average annual interest rate on EQM's long-term debt was 4.0% for each of 2016, 2015 and 2014.

The Company did not have any borrowings outstanding at any time under its revolving credit facility during the years ended December 31, 2016, 2015 and 2014. The maximum amount of outstanding borrowings under EQM's $750 million credit facility

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at any time during the years ended December 31, 2016, 2015 and 2014 was $401 million, $404 million and $450 million, respectively. The average daily balance of borrowings outstanding under EQM's $750 million credit facility was approximately $77 million, $261 million and $119 million during the years ended December 31, 2016, 2015 and 2014, respectively. Interest was incurred on such borrowings at weighted average annual interest rates of approximately 2.0%, 1.7% and 1.7% for the years ended December 31, 2016, 2015 and 2014, respectively.

Income Taxes

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Income tax (benefit) expense	$(263,464)	$104,675	$214,092

All of EQGP's income is included in the Company's pre-tax income (loss). However, the Company is not required to record income tax expense with respect to the portions of EQGP's income allocated to the noncontrolling public limited partners of EQGP and EQM, which reduces the Company's effective tax rate in periods when the Company has consolidated pre-tax income and increases the Company's effective tax rate in periods when the Company has consolidated pre-tax loss.

For federal income tax purposes, the Company may deduct a portion of its drilling costs as intangible drilling costs (IDCs) in the year incurred. IDCs, however, are sometimes limited for purposes of the alternative minimum tax (AMT) and can result in the Company paying AMT even when generating large tax deductions or utilizing a net operating loss (NOL) carryforward.

For 2016, the Company is in a breakeven federal taxable income position and is paying a small amount of tax. For 2015 and 2014, the Company paid a larger amount of tax as a result of the large tax gains generated from EQGP’s IPO in 2015, the NWV Gathering Transaction in 2015 and the Jupiter Transaction in 2014 (defined in Note 4 to the Consolidated Financial Statements).

See Note 10 to the Consolidated Financial Statements for further discussion of the Company’s income tax (benefit) expense.

Net Income Attributable to Noncontrolling Interests

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Net income attributable to noncontrolling interests	$321,920	$236,715	$124,025

The increase in net income attributable to noncontrolling interests for all periods was primarily the result of increased net income at EQM, increased ownership of EQM common units by third-parties and EQGP's IPO in 2015.

Outlook

The Company is committed to profitably developing its natural gas and NGLs reserves through environmentally responsible, cost-effective and technologically advanced horizontal drilling. The Company’s revenues, earnings, liquidity and ability to grow are substantially dependent on the prices it receives for, and the Company’s ability to develop its reserves of natural gas and NGLs. Despite the continued low price environment for natural gas and NGLs, the Company believes the long-term outlook for its business is favorable due to the Company's resource base, low cost structure, financial strength, risk management, including commodity hedging strategy, and disciplined investment of capital. The Company believes the combination of these factors provide it with an opportunity to exploit and develop its positions and maximize efficiency through economies of scale in its strategic operating area.

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. In addition, the market price for natural gas in the Appalachian Basin was 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, and NGLs and thus cannot predict the ultimate impact of prices on our operations.

The Company's 2017 capital expenditure forecast for well development is $1.3 billion, which is 66% higher than its 2016 capital expenditures for well development. Changes in natural gas, NGLs and oil prices could affect, among other things, the Company's development plans, which would increase or decrease the pace of the development and the level of the Company's reserves, as well as the Company's revenues, earnings or liquidity. Significant changes in prices may result in an increase or decrease in capital spending. Lower prices could result in additional non-cash impairments in the book value of the Company’s oil and gas properties or additional downward adjustments to the Company’s estimated proved reserves. Any such additional impairment and/or downward adjustment to the Company’s estimated reserves could potentially be material to the Company. See “Impairment of Oil and Gas Properties” below.

In July 2015, the Company turned in-line its first dry gas focused Utica well, which experienced prolific initial results. The Company has subsequently turned in-line 4 additional Utica wells located in Greene County, Pennsylvania and Wetzel County, West Virginia, with 2 additional wells spud but not yet complete as of December 31, 2016. Given the results of its initial Utica wells, the Company will continue development of its Utica acreage in 2017.

Total capital investment by EQT in 2017, excluding acquisitions, is expected to be approximately $2.0 billion (including EQM). Capital spending for well development (primarily drilling and completion) of approximately $1.3 billion in 2017 is expected to support the drilling of approximately 207 gross wells, including 119 Marcellus wells, 81 Upper Devonian wells and 7 Utica wells. Estimated sales volumes are expected to be 810 - 830 Bcfe, which includes volume growth of approximately 60 Bcfe, the majority of which stems from the previous year's drilling program. The majority of the volume expected from the 2017 drilling program will be realized in 2018, at which time EQT forecasts production volume growth of 15 - 20% per year for several years. The anticipated production sales volume growth is approximately 8% in 2017, while total NGLs volumes are expected to be 13,200 - 13,800 Mbbls. To support continued growth in production, the Company plans to invest approximately $0.5 billion on midstream infrastructure through EQM. The 2017 capital investment plan for EQT Production is expected to be funded by cash generated from operations, cash on hand and sales of trading securities. EQM's available sources of liquidity include cash generated from operations, borrowings under its credit facilities, cash on hand, debt offerings and issuances of additional EQM partnership interests.

The Company continues to focus on creating and maximizing shareholder value through the implementation of a strategy that economically accelerates the monetization of its asset base and prudently pursues investment opportunities, all while maintaining a strong balance sheet with solid cash flow. The Company monitors current and expected market conditions, including the commodity price environment, and its liquidity needs and may adjust its capital investment plan accordingly. While the tactics continue to evolve based on market conditions, the Company periodically considers arrangements to monetize the value of certain mature assets for re-deployment into its highest value development opportunities. The Company continues to pursue transactions that would add to its Marcellus, Upper Devonian and Utica positions and would consider purchasing assets or companies of various sizes within those positions.

Impairment of Oil and Gas Properties

See “Critical Accounting Policies and Estimates” below and Note 1 to the Consolidated Financial Statements for a discussion of the Company’s accounting policies and significant assumptions related to impairment of the Company’s oil and gas properties. Due to declines in the five-year NYMEX forward strip prices during 2015 and into 2016, the Company determined that indicators of potential impairment existed for certain of the Company’s proved oil and gas properties as of December 31, 2016. In accordance with its normal procedures, the Company estimated the future undiscounted cash flows from these oil and gas properties and compared these estimates to the carrying value of the properties. Based on these evaluations, the Company determined that no impairment existed during 2016. Although the Company did not record an impairment on its oil and gas producing properties during 2016, 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.

As described under “Critical Accounting Policies and Estimates” below, the Company makes a number of assumptions related to its evaluation of its oil and gas properties for impairment, many of which require the Company’s management to make significant judgments. These assumptions, which are generally consistent with the assumptions utilized by the Company’s management for internal planning and budgeting purposes, include, among other things, anticipated production from reserves; future market prices for natural gas, NGLs and oil adjusted accordingly for basis differentials; future operating and capital costs; and inflation. Future market prices for natural gas, NGLs and oil are often volatile, and assumptions regarding basis differentials, future production and future operating costs are highly judgmental and in some cases difficult to predict. Due to the uncertainty inherent in, and the interdependence of these factors, the Company cannot predict if future impairment charges, including impairment charges related to its Huron oil and gas properties, will be recognized and, if so, an estimate of the impairment charges that would be recorded in any future period. See “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

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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." under Item 1A, "Risk Factors."

Capital Resources and Liquidity

The Company's primary sources of cash for the year ended December 31, 2016 were proceeds from the public offerings of EQT common stock and cash flows from operating activities, while the primary use of cash was for capital expenditures.

Operating Activities

The Company's net cash provided by operating activities decreased $152.6 million from full year 2015 to full year 2016 and by $197.8 million from full year 2014 to full year 2015. Decreases in cash flows provided by operating activities in both periods were primarily the result of a lower commodity price and higher operating expenses, partly offset by higher production sales volumes, cash settlements on derivatives not designated as hedges, decreases in cash paid for income taxes and the timing of payments between periods.

The Company's cash flows from operating activities will be impacted by future movements in the market price for commodities. The Company is unable to predict these future price movements. See "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" under Item 1A, "Risk Factors" for further information.

Investing Activities

Cash flows used in investing activities totaled $2,961.5 million for 2016 as compared to $2,525.6 million for 2015. The $435.9 million increase was primarily due to an increase in capital expenditures for acquisitions of $1,051.2 million and investments in trading securities of $288.8 million, partly offset by a reduction in the drilling and completions capital expenditures. During 2016, the Company invested in trading securities, which consist of liquid debt securities carried at fair value, to maximize returns. The Company also placed $75.0 million of the proceeds received from the sale of a gathering system into restricted cash for a potential like-kind exchange for tax purposes.

Cash flows used in investing activities totaled $2,525.6 million for 2015 as compared to $2,444.2 million for 2014. The $81.4 million increase was primarily attributable to a $156.7 million increase in capital expenditures and $74.5 million of net capital contributions made to the MVP Joint Venture through EQM during 2015, partly offset by $174.2 million of capital expenditures in 2014 in connection with the 2014 exchange of assets with Range Resources.

Capital Expenditures from Continuing Operations
(in millions)

	2016 Actual	2015 Actual	2014 Actual
Well development (primarily drilling and completion)	$783	$1,670	$1,717
Property acquisitions	1,284	182	724
Production midstream infrastructure	7	41	64
Gathering	295	226	254
Transmission	292	204	137
Other corporate items	7	21	4
Total	$2,668	$2,344	$2,900
Less: non-cash *	77	(90)	448

Total cash capital expenditures	$2,591	$2,434	$2,452

* Represents the net impact of non-cash capital expenditures including capitalized non-cash stock-based compensation expense and accruals. The impact of accrued capital expenditures includes the reversal of the prior period accrual as well as the current period estimate, both of which are non-cash items. The year ended December 31, 2016 included $87.6 million of non-cash capital expenditures related to acquisitions, and the year ended December 31, 2014 included $349 million of non-cash capital expenditures for the exchange of assets with Range Resources.

The Company has forecast a 2017 capital expenditure spending plan of approximately $2.0 billion (excluding acquisitions), which includes $1.3 billion for well development (primarily drilling and completion), an EQM 2017 capital expenditure spending plan of approximately $0.5 billion and $0.2 billion for other items. The Company does not forecast property acquisitions within its capital spending plan.

Capital expenditures for drilling and development totaled $783 million and $1,670 million during 2016 and 2015, respectively. The Company spud 135 gross wells in 2016, including 117 horizontal Marcellus wells, 13 horizontal Upper Devonian wells and 4 Utica wells. The Company spud 161 gross wells in 2015, including 133 horizontal Marcellus wells, 24 horizontal Upper Devonian wells and 4 other wells, including 2 Utica wells. The decrease in capital expenditures for well development in 2016 was driven primarily by the timing of drilling and completions activities between years, a decrease in wells spud, lower costs per well and operational efficiencies. Capital expenditures for 2016 also included $1,284 million for property acquisitions, compared to $182 million of capital expenditures in 2015 for property acquisitions. The Company executed multiple large transactions during 2016 that resulted in the Company's acquisition of approximately 122,100 net Marcellus acres located primarily in northern West Virginia and southwestern Pennsylvania discussed in Note 8 to the Consolidated Financial Statements.

Capital expenditures for drilling and development totaled $1,670 million and $1,717 million during 2015 and 2014, respectively. The Company spud 345 gross wells in 2014, including 196 horizontal Marcellus wells, 41 horizontal Upper Devonian wells, 103 horizontal Huron wells and 5 other wells. The $47 million decrease in capital expenditures for well development in 2015 was driven primarily by a decrease in wells spud partly offset by increased costs of Utica drilling. Capital expenditures for 2015 also included $182 million for property acquisitions, compared to $724 million of capital expenditures in 2014 for property acquisitions.

Capital expenditures for the gathering and transmission operations totaled $587 million for 2016 and $430 million for 2015, primarily related to expansion capital expenditures. Expansion capital expenditures are expenditures incurred for capital improvements that EQM expects to increase its operating income or operating capacity over the long term. This increase in expansion capital expenditures primarily related to OVC, which was placed into service in the fourth quarter of 2016.

Capital expenditures for the gathering, transmission and storage operations totaled $430 million for 2015 and $391 million for 2014, primarily related to expansion capital expenditures.

Financing Activities

Cash flows provided by financing activities totaled $1,399.5 million for 2016 as compared to $1,832.5 million for 2015. During 2016, the Company's primary sources of financing cash flows were net proceeds from its public offerings of common stock and from EQM's public offerings of common units under the $750 million ATM Program, as well as proceeds received from the issuance of EQM debt. The primary financing uses of cash during 2016 were net credit facility repayments under the EQM credit facility, distributions to noncontrolling interests, taxes related to the vesting or exercise of equity awards and dividends.

On January 18, 2017, the Board of Directors of the Company declared a regular quarterly cash dividend of three cents per share, payable March 1, 2017, to the Company’s shareholders of record at the close of business on February 17, 2017.

On January 19, 2017, the Board of Directors of EQGP's general partner declared a cash distribution to EQGP's unitholders for the fourth quarter of 2016 of $0.177 per common unit, or approximately $47.1 million. The cash distribution will be paid on February 23, 2017 to unitholders of record, including the Company, at the close of business on February 3, 2017.

On January 19, 2017, the Board of Directors of EQM's general partner declared a cash distribution to EQM's unitholders for the fourth quarter of 2016 of $0.85 per common unit. The cash distribution will be paid on February 14, 2017 to unitholders of record, including EQGP, at the close of business on February 3, 2017. Based on the 80,581,758 EQM common units outstanding on February 9, 2017, the aggregate cash distributions by EQM to EQGP will be approximately $47.9 million consisting of: $18.5 million in respective to its limited partner interest, $1.8 million in respect of its general partner interest and $27.6 million in respect of its IDRs in EQM.

Cash flows provided by financing activities totaled $1,832.5 million for 2015 as compared to $1,261.3 million for 2014. During 2015, the Company's primary sources of financing cash flows were net proceeds from EQM's public offerings of common units, including sales under the $750 million ATM Program, net proceeds from EQGP's IPO and net borrowings on EQM's revolving credit facility. The primary financing uses of cash during 2015 were payments on maturing long-term debt, distributions to noncontrolling interests and taxes related to the vesting or exercise of equity awards.

On April 30, 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. During the year ended December 31, 2014, the Company repurchased and retired 300,000 shares of common stock for $32.4 million under the authorization. The Company made no repurchases under the authorization during 2016 and 2015.

The Company may from time to time seek to repurchase its outstanding debt securities. Such repurchases, if any, will depend on prevailing market conditions, the Company's liquidity requirements, contractual and legal restrictions and other factors.

Revolving Credit Facilities

EQT primarily utilizes borrowings under its revolving credit facilities to fund capital expenditures in excess of cash flow from operating activities until the expenditures can be permanently financed and to fund required margin deposits on derivative commodity instruments. Margin deposit requirements vary based on natural gas commodity prices, the Company's credit ratings and the amount and type of derivative commodity instruments.

The Company has a $1.5 billion unsecured revolving credit facility that expires in February 2019. The Company may request two one-year extensions of the expiration date, the approval of which is subject to satisfaction of certain conditions.

The revolving credit facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes. The credit facility is underwritten by a syndicate of 18 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company.

Under the terms of the revolving credit facility, the Company may obtain base rate loans or fixed period Eurodollar rate loans. Base rate loans are denominated in dollars and bear interest at a base rate plus a margin based on the Company’s then current credit ratings. Fixed period Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on the Company’s then current credit ratings.

The Company had no borrowings or letters of credit outstanding under its revolving credit facility as of December 31, 2016 and 2015 or at any time during the years ended December 31, 2016 and 2015. For the years ended December 31, 2016 and 2015, the Company incurred commitment fees averaging approximately 23 basis points to maintain credit availability under its revolving credit facility.

EQM has a $750 million credit facility that expires in February 2019. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions and repurchase units and for general partnership purposes. The credit facility is underwritten by a syndicate of 18 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by EQM. The Company is not a guarantor of EQM’s obligations under the credit facility.

Under the terms of its revolving credit facility, EQM may obtain base rate loans or fixed period Eurodollar rate loans. Base rate loans are denominated in dollars and bear interest at a base rate plus a margin based on EQM’s then current credit rating. Fixed period Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on EQM’s then current credit ratings.

EQM had no borrowings and no letters of credit outstanding under its revolving credit facility as of December 31, 2016. EQM had $299 million of borrowings and no letters of credit outstanding under its revolving credit facility as of December 31, 2015. For the years ended December 31, 2016 and 2015, EQM incurred commitment fees averaging approximately 23 basis points to maintain credit availability under the revolving credit facility.

The maximum amount of outstanding borrowings at any time under EQM's credit facility during the year ended December 31, 2016 was $401 million, and the average daily balance of borrowings outstanding was approximately $77 million at a weighted average annual interest rate of 2.0%. The maximum amount of outstanding borrowings at any time under EQM's credit facility during the year ended December 31, 2015 was $404 million, and the average daily balance of borrowings outstanding was approximately $261 million at a weighted average annual interest rate of 1.7%.

See also the discussion of the revolving loan agreement between EQT and EQM in Note 4 to the Consolidated Financial Statements.

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Security Ratings and Financing Triggers

The table below reflects the credit ratings for debt instruments of the Company at December 31, 2016. Changes in credit ratings may affect the Company's cost of short-term debt through interest rates and fees under its lines of credit. These ratings may also affect collateral requirements under derivative instruments, pipeline capacity contracts, joint venture arrangements and subsidiary construction contracts, rates available on new long-term debt and access to the credit markets.

Rating Service	Senior Notes	Outlook
Moody's Investors Service (Moody's)	Baa3	Stable
Standard & Poor's Ratings Service (S&P)	BBB	Stable
Fitch Ratings Service (Fitch)	BBB-	Stable

The table below reflects the credit ratings for debt instruments of EQM at December 31, 2016. Changes in credit ratings may affect EQM's cost of short-term debt through interest rates and fees under its lines of credit. These ratings may also affect collateral requirements under joint venture arrangements and subsidiary construction contracts, rates available on new long-term debt and access to the credit markets.

Rating Service	Senior Notes	Outlook
Moody's	Ba1	Stable
S&P	BBB-	Stable
Fitch	BBB-	Stable

The Company's and EQM's credit ratings are subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. The Company and EQM cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn by a credit rating agency if, in its judgment, circumstances so warrant. If any credit rating agency downgrades the ratings, particularly below investment grade, the Company's or EQM's access to the capital markets may be limited, borrowing costs and margin deposits on the Company's derivative contracts would increase, counterparties may request additional assurances, including collateral, and the potential pool of investors and funding sources may decrease. The required margin on the Company's derivative instruments is also subject to significant change as a result of factors other than credit rating, such as gas prices and credit thresholds set forth in agreements between the hedging counterparties and the Company. 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, a company must be rated BBB- or higher by S&P, Baa3 or higher by Moody's, and BBB- or higher by Fitch. Anything below these ratings is considered non-investment grade.

The Company's debt agreements and other financial obligations contain various provisions that, if not complied with, could result in termination of the agreements, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the debt agreements relate to maintenance of a debt-to-total capitalization ratio, limitations on transactions with affiliates, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company's credit facility contains financial covenants that require a total debt-to-total capitalization ratio no greater than 65%. The calculation of this ratio excludes the effects of accumulated other comprehensive income (OCI). As of December 31, 2016, the Company was in compliance with all debt provisions and covenants.

EQM's debt agreements and other financial obligations contain various provisions that, if not complied with, could result in termination of the agreements, require early payment of amounts outstanding or similar actions. The covenants and events of default under the debt agreements relate to maintenance of a permitted leverage ratio, limitations on transactions with affiliates, limitations on restricted payments, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of and certain other defaults under other financial obligations and change of control provisions. Under EQM's $750 million credit facility, EQM is required to maintain a consolidated leverage ratio of not more than 5.00 to 1.00 (or not more than 5.50 to 1.00 for certain measurement periods following the consummation of certain acquisitions). As of December 31, 2016, EQM was in compliance with all debt provisions and covenants.

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EQM ATM Program

During 2015, EQM entered into an equity distribution agreement that established the $750 million ATM Program. EQM had approximately $443 million in remaining capacity under the program as of February 9, 2017.

Commodity Risk Management

The substantial majority of the Company's commodity risk management program is related to hedging sales of the Company's produced natural gas. The Company's overall objective in this hedging program is to protect cash flow from undue exposure to the risk of changing commodity prices. The derivative commodity instruments currently utilized by the Company are primarily NYMEX swaps and collars.

As of January 31, 2017, the approximate volumes and prices of the Company's derivative commodity instruments hedging sales of produced gas for 2017 through 2019 were:

	2017 (a)(b)	2018 (a)(b)	2019
NYMEX Swaps			
Total Volume (Bcf)	362	135	19
Average Price per Mcf (NYMEX) (d)	$3.35	$3.14	$3.12
Collars			
Total Volume (Bcf)	22	—	—
Average Floor Price per Mcf (NYMEX) (d)	$3.03	$—	$—
Average Cap Price per Mcf (NYMEX) (d)	$3.94	$—	$—

(a) The Company also sold calendar year 2017 and 2018 calls for approximately 32 Bcf and 16 Bcf, respectively, at strike prices of $3.53 per Mcf and $3.48 per Mcf, respectively.
(b) For 2017 and 2018, the Company also sold puts for approximately 3 Bcf each year at a strike price of $2.63 per Mcf.
(c) The average price is based on a conversion rate of 1.05 MMBtu/Mcf.

The Company also enters into fixed price natural gas sales agreements that are satisfied by physical delivery. The difference between these sales prices and NYMEX are included in average differential on the Company's price reconciliation under "Consolidated Operational Data". The Company has fixed price physical sales for 2017 and 2018 of 44 Bcf and 5 Bcf, respectively, at average prices of $3.16 per Mcf and $3.29 per Mcf, respectively. For 2017 and 2018, the Company has a natural gas sales agreement for approximately 35 Bcf per year that includes a NYMEX ceiling price of $4.88 per Mcf. For 2018 and 2019, the Company has a natural gas sales agreement for approximately 7 Bcf per year that includes a NYMEX floor price of $2.16 per Mcf and a ceiling price of $4.47 per Mcf. Currently, the Company has also entered into derivative instruments to hedge basis and a limited number of contracts to hedge its NGLs exposure. The Company may also use other contractual agreements in implementing its commodity hedging strategy.

See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," and Note 6 to the Consolidated Financial Statements for further discussion of the Company's hedging program.

Other Items

Off-Balance Sheet Arrangements

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that once the energy-efficiency construction was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a period of years. The undiscounted maximum aggregate payments that may be due related to these guarantees were approximately $115 million as of December 31, 2016, extending at a decreasing amount for approximately 12 years.

As of December 31, 2016, EQM had issued a $91 million performance guarantee (the Initial Guarantee) in connection with the obligations of MVP Holdco, LLC (MVP Holdco) to fund its proportionate share of the construction budget for the MVP. Upon the FERC’s initial release to begin construction of the MVP, the Initial Guarantee will terminate, and EQM will be obligated to issue a new guarantee in an amount equal to 33% of MVP Holdco’s remaining obligations to make capital contributions to the MVP Joint Venture in connection with the then remaining construction budget, less, subject to certain limits, any credit assurances issued by an affiliate of EQM under such affiliate's precedent agreement with the MVP Joint Venture.

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The NORESCO guarantees and the Initial Guarantee are exempt from ASC Topic 460, Guarantees. The Company has determined that the likelihood it will be required to perform on these arrangements is remote and any potential payments are expected to be immaterial to the Company's financial position, results of operations and liquidity. As such, the Company has not recorded any liabilities in its Consolidated Balance Sheets related to these guarantees.

Rate Regulation

As described under "Regulation" in Item 1, "Business," the Company's transmission and storage operations and a portion of its gathering operations are subject to various forms of rate regulation. As described in Note 1 to the Consolidated Financial Statements, regulatory accounting allows the Company to defer expenses and income as regulatory assets and liabilities which reflect future collections or payments through the regulatory process. The Company believes that it will continue to be subject to rate regulation that will provide for the recovery of the deferred costs.

Schedule of Contractual Obligations

The table below presents the Company's long-term contractual obligations as of December 31, 2016 in total and by periods. Purchase obligations exclude the Company's contractual obligations relating to its binding precedent agreements and other natural gas transmission and gathering capacity agreements with EQM, for which future payments related to such agreements totaled $6.0 billion as of December 31, 2016. These capacity commitments have terms extending up to 20 years. For a description of the transportation agreements, see Note 20 to the Consolidated Financial Statements. Purchase obligations also exclude future capital contributions to the MVP Joint Venture and purchase obligations of the MVP Joint Venture.

	Total	2017	2018-2019	2020-2021	2022+
	(Thousands)				
Purchase obligations	$11,631,378	$446,214	$1,237,662	$1,454,506	$8,492,996
Long-term debt	3,318,200	—	1,408,000	785,200	1,125,000
Interest payments on long-term debt (a)	970,698	190,270	346,954	203,424	230,050
Operating leases	143,314	55,496	36,753	19,581	31,484
Post-retirement benefits	22,493	1,666	3,101	2,848	14,878
Other liabilities	51,897	21,297	30,600	—	—
Total contractual obligations	$16,137,980	$714,943	$3,063,070	$2,465,559	$9,894,408

(a) Interest payments exclude interest due related to the credit facility borrowings as the interest rate on EQM's credit facility agreement is variable.

Purchase obligations are primarily commitments for demand charges under existing long-term contracts and binding precedent agreements with various unconsolidated pipelines, including commitments from the Company to the MVP Joint Venture, some of which extend up to approximately 20 years. The Company has entered into agreements to release some of its capacity to various third parties. Purchase obligations also include commitments with third parties for processing capacity in order to extract heavier liquid hydrocarbons from the natural gas stream. Operating leases are primarily entered into for various office locations and warehouse buildings, as well as dedicated drilling rigs in support of the Company's drilling program. The obligations for the Company's various office locations and warehouse buildings totaled approximately $44.1 million as of December 31, 2016. The Company has agreements with several drillers to provide drilling equipment and services to the Company over the next four years. These obligations totaled approximately $60.9 million as of December 31, 2016.

The other liabilities line represents commitments for total estimated payouts for the 2016 EQT Value Driver Award Program and 2016 restricted stock unit liability awards. See “Critical Accounting Policies and Estimates” below and Note 18 to the Consolidated Financial Statements for further discussion regarding factors that affect the ultimate amount of the payout of these obligations.

As discussed in Note 10 to the Consolidated Financial Statements, the Company had a total reserve for unrecognized tax benefits at December 31, 2016 of $252.4 million, of which $75.4 million is offset against deferred tax assets since it would primarily reduce the alternative minimum tax credit carryforwards. The Company is currently unable to make reasonably reliable estimates of the period of cash settlement of these potential liabilities with taxing authorities; therefore, this amount has been excluded from the schedule of contractual obligations.

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Commitments and Contingencies

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 Company's financial position, results of operations or liquidity.

See Note 20 to the Consolidated Financial Statements for further discussion of the Company's commitments and contingencies. See also the discussion of the revolving loan agreement between EQT and EQM in Note 4 to the Consolidated Financial Statements.

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Recently Issued Accounting Standards

The Company's recently issued accounting standards are described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Critical Accounting Policies and Estimates

The Company’s significant accounting policies are described in Note 1 to the Consolidated Financial Statements. The discussion and analysis of the Consolidated Financial Statements and results of operations are based upon the Company’s Consolidated Financial Statements, which have been prepared in accordance with United States GAAP. The preparation of the Consolidated Financial Statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. The following critical accounting policies, which were reviewed by the Company’s Audit Committee, relate to the Company’s more significant judgments and estimates used in the preparation of its Consolidated Financial Statements. Actual results could differ from those estimates.

Accounting for Oil and Gas Producing Activities: The Company uses the successful efforts method of accounting for its oil and gas producing activities.

The carrying values of the Company’s proved oil and gas properties are reviewed for impairment generally on a field-by-field basis when events or circumstances indicate that the remaining carrying value may not be recoverable. The estimated future cash flows used to test those 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 intended use of the asset, anticipated production from reserves, future market prices for natural gas, NGLs and oil, adjusted accordingly for basis differentials, future operating costs and inflation, some of which are interdependent. Proved oil and gas properties 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 rates and other assumptions that marketplace participants would use in their estimates of fair value.

Capitalized costs of unproved properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes in development plans resulting from economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves prior to their expirations, the related costs are expensed in the period in which that determination is made.

The Company believes that the accounting estimate related to the accounting for oil and gas producing activities is a “critical accounting estimate” as the evaluations of impairment of proved properties involve significant judgment about future events such as future sales prices of natural gas and NGLs, future production costs, estimates of the amount of natural gas and NGLs recorded and the timing of those recoveries. See "Impairment of Oil and Gas Properties" above and Note 1 to the Consolidated Financial Statements for additional information regarding the Company’s impairments of proved and unproved oil and gas properties.

Oil and Gas Reserves: Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10, are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

The Company’s estimates of proved reserves are made and reassessed annually using geological and reservoir data as well as production performance data. Reserve estimates are prepared and updated by the Company’s engineers and audited by the Company’s independent engineers. Revisions may result from changes in, among other things, reservoir performance, development plans, prices, operating costs, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits sooner. A material change in the estimated volumes of reserves could have an impact on the depletion rate calculation and the Company's financial statements, including strength of the balance sheet.

The Company estimates future net cash flows from natural gas, NGLs and oil reserves based on selling prices and costs using a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period, which is subject to change in subsequent periods. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation. Income tax expense is computed using statutory future tax rates and giving effect to tax deductions and credits available under current laws and which relate to oil and gas producing activities.

The Company believes that the accounting estimate related to oil and gas reserves is a "critical accounting estimate" because the Company must periodically reevaluate proved reserves along with estimates of future production rates, production costs and the estimated timing of development expenditures. Future results of operations and strength of the balance sheet for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions. See "Impairment of Oil and Gas Properties" above for additional information regarding the Company's oil and gas reserves.

Income Taxes: The Company recognizes deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the Company's Consolidated Financial Statements or tax returns.

The Company has recorded deferred tax assets principally resulting from federal and state NOL carryforwards, an alternative minimum tax credit carryforward, incentive compensation, unrealized hedge losses and investment in EQGP. The Company has established a valuation allowance against a portion of the deferred tax assets related to the federal and state NOL carryforwards, as it is believed that it is more likely than not that these deferred tax assets will not all be realized. No other significant valuation allowances have been established, as it is believed that future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize these deferred tax assets. Any determination to change the valuation allowance would impact the Company's income tax expense and net income in the period in which such a determination is made.

The Company also estimates the amount of financial statement benefit to record for uncertain tax positions as described in Note 10 to the Company's Consolidated Financial Statements.

The Company believes that accounting estimates related to income taxes are "critical accounting estimates" because the Company must assess the likelihood that deferred tax assets will be recovered from future taxable income and exercise judgment regarding the amount of financial statement benefit to record for uncertain tax positions. When evaluating whether or not a valuation allowance must be established on deferred tax assets, the Company exercises judgment in determining whether it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized. The Company considers all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed, including carrybacks, tax planning strategies, reversal of deferred tax assets and liabilities and forecasted future taxable income. In making the determination related to uncertain tax positions, the Company considers the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of financial statement benefit. To the extent that an uncertain tax position or valuation allowance is established or increased or decreased during a period, the Company must include an expense or benefit within tax expense in the income statement. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions.

Derivative Instruments: The Company enters into derivative commodity instrument contracts primarily to mitigate exposure to commodity price risk associated with future sales of natural gas production. The Company also enters into derivative instruments to hedge basis and to hedge exposure to fluctuations in interest rates.

The Company estimates the fair value of all derivative instruments using quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use market-based parameters as inputs, including forward curves, discount rates, volatilities and nonperformance risk. Nonperformance risk considers the effect of the Company's credit standing on the fair value of liabilities and the effect of the counterparty's credit standing on the fair value of assets. The Company estimates nonperformance risk by analyzing publicly available market information, including a comparison of the yield on debt instruments with credit ratings similar to the Company's or counterparty's credit rating and the yield of a risk-free instrument, and credit default swap rates where available. The values reported in the financial statements change as these estimates are revised to reflect actual results, or market conditions or other factors change, many of which are beyond the Company's control.

The Company believes that the accounting estimates related to derivative instruments are "critical accounting estimates" because the Company's financial condition and results of operations can be significantly impacted by changes in the market value of the Company's derivative instruments due to the volatility of natural gas prices, both NYMEX and basis. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions.

Contingencies and Asset Retirement Obligations: The Company is involved in various regulatory and legal proceedings that arise in the ordinary course of business. The Company records a liability for contingencies based upon its assessment that a loss is probable and the amount of the loss can be reasonably estimated. The Company considers many factors in making these assessments, including history and specifics of each matter. Estimates are developed in consultation with legal counsel and are based upon an analysis of potential results.

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The Company also accrues a liability for asset retirement obligations based on an estimate of the timing and amount of their settlement. For oil and gas wells, the fair value of the Company's plugging and abandonment obligations is required to be recorded at the time the obligations are incurred, which is typically at the time the wells are spud. The Company is required to operate and maintain its natural gas pipeline and storage systems, and intends to do so as long as supply and demand for natural gas exists, which the Company expects for the foreseeable future. Therefore, the Company believes that the substantial majority of its natural gas pipeline and storage system assets have indeterminate lives.

The Company believes that the accounting estimates related to contingencies and asset retirement obligations are "critical accounting estimates" because the Company must assess the probability of loss related to contingencies and the expected amount and timing of asset retirement obligations. In addition, the Company must determine the estimated present value of future liabilities. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions.

Share-Based Compensation: The Company awards share-based compensation in connection with specific programs established under the 2009 and 2014 Long-Term Incentive Plans. Awards to employees are typically made in the form of performance-based awards, time-based restricted stock, time-based restricted units and stock options. Awards to directors are typically made in the form of phantom units that vest upon grant.

Restricted units and performance-based awards expected to be satisfied in cash are treated as liability awards. For liability awards, the Company is required to estimate, on grant date and on each reporting date thereafter until vesting and payment, the fair value of the ultimate payout based upon the expected performance through, and value of the Company's common stock on, the vesting date. The Company then recognizes a proportionate amount of the expense for each period in the Company's financial statements over the vesting period of the award. The Company reviews its assumptions regarding performance and common stock value on a quarterly basis and adjusts its accrual when changes in these assumptions result in a material change in the fair value of the ultimate payouts.

Performance-based awards expected to be satisfied in Company common stock are treated as equity awards. For equity awards, the Company is required to determine the grant date fair value of the awards, which is then recognized as expense in the Company's financial statements over the vesting period of the award. Determination of the grant date fair value of the awards requires judgments and estimates regarding, among other things, the appropriate methodologies to follow in valuing the awards and the related inputs required by those valuation methodologies. Most often, the Company is required to obtain a valuation based upon assumptions regarding risk-free rates of return, dividend yields, expected volatilities and the expected term of the award. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the historical dividend yield of the Company's common stock adjusted for any expected changes and, where applicable, of the common stock of the peer group members at the time of grant. Expected volatilities are based on historical volatility of the Company's common stock and, where applicable, the common stock of the peer group members at the time of grant. The expected term represents the period of time elapsing during the applicable performance period.

For time-based restricted stock awards, the grant date fair value of the awards is recognized as expense in the Company's financial statements over the vesting period, historically three years. For director phantom units (which vest on date of grant) expected to be satisfied in equity, the grant date fair value of the awards is recognized as an expense in the Company's financial statements in the year of grant. The grant date fair value, in both cases, is determined based upon the closing price of the Company's common stock on the date of the grant.

For non-qualified stock options, the grant date fair value is recognized as expense in the Company's financial statements over the vesting period, typically two or three years. The Company utilizes the Black-Scholes option pricing model to measure the fair value of stock options, which includes assumptions for a risk-free interest rate, dividend yield, volatility factor and expected term. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the dividend yield of the Company's common stock at the time of grant. The expected volatility is based on historical volatility of the Company's common stock at the time of grant. The expected term represents the period of time that options granted are expected to be outstanding based on historical option exercise experience at the time of grant.

The Company believes that the accounting estimates related to share-based compensation are "critical accounting estimates" because they may change from period to period based on changes in assumptions about factors affecting the ultimate payout of awards, including the number of awards to ultimately vest and the market price and volatility of the Company's common stock. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions. See Note 18 to the Consolidated Financial Statements for additional information regarding the Company's share-based compensation.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk and Derivative Instruments

The Company’s primary market risk exposure is the volatility of future prices for natural gas and NGLs. 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, the Company is unable to predict future potential movements in the market prices for natural gas, including Appalachian basis, and NGLs and thus cannot predict the ultimate impact of prices on its operations. Prolonged low, and/or significant or extended declines in, natural gas and NGLs prices could adversely affect, among other things, the Company’s development plans, which would decrease the pace of development and the level of the Company’s proved reserves. Such changes or similar impacts on third-party shippers on the Company's midstream assets could also impact the Company’s revenues, earnings or liquidity and could result in a material non-cash impairment in the recorded value of the Company’s property, plant and equipment.

In addition to the ability to elect to slow capital spending in periods of prolonged low, and/or significant declines in, natural gas and NGLs prices, the Company uses derivatives to reduce the effect of commodity price volatility. The Company's use of derivatives is further described in Notes 1 and 6 to the Consolidated Financial Statements and under the caption “Commodity Risk Management” in the "Capital Resources and Liquidity" section of Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The Company uses derivative commodity instruments that are placed primarily with financial institutions and the creditworthiness of these institutions is regularly monitored. The Company primarily enters into derivative instruments to hedge forecasted sales of production. The Company also enters into derivative instruments to hedge basis and exposure to fluctuations in interest rates. The Company’s use of derivative instruments is implemented under a set of policies approved by the Company’s Hedge and Financial Risk Committee and reviewed by the Audit Committee of the Company's Board of Directors.

For the derivative commodity instruments used to hedge the Company’s forecasted sales of production, most of which are hedged at NYMEX natural gas prices, the Company sets policy limits relative to the expected production and sales levels which are exposed to price risk. The Company has an insignificant amount of financial natural gas derivative commodity instruments for trading purposes.

The derivative commodity instruments currently utilized by the Company are primarily fixed price swap agreements and collar agreements which may require payments to or receipt of payments from counterparties based on the differential between two prices for the commodity. The Company may also use other contractual agreements in implementing its commodity hedging strategy.

The Company monitors price and production levels on a continuous basis and makes adjustments to quantities hedged as warranted. The Company’s overall objective in its hedging program is to protect a portion of cash flows from undue exposure to the risk of changing commodity prices.

With respect to the derivative commodity instruments held by the Company, the Company hedged portions of expected sales of equity production and portions of its basis exposure covering approximately 646 Bcf of natural gas and 1,095 Mbbls of NGLs as of December 31, 2016 and 664 Bcf of natural gas as of December 31, 2015. See the “Commodity Risk Management” section in the “Capital Resources and Liquidity” section of Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” for further discussion.

A hypothetical decrease of 10% in the market price of natural gas from the December 31, 2016 and 2015 levels would have increased the fair value of natural gas derivative instruments by approximately $179.0 million and $137.1

million, respectively. A hypothetical increase of 10% in the market price of natural gas from the December 31, 2016 and 2015 levels would have decreased the fair value of natural gas derivative instruments by approximately $181.8 million and $138.4 million, respectively. The Company determined the change in the fair value of the derivative commodity instruments using a method similar to its normal determination of fair value as described in Note 1 to the Consolidated Financial Statements. The Company assumed a 10% change in the price of natural gas from its levels at December 31, 2016 and December 31, 2015. The price change was then applied to the natural gas derivative commodity instruments recorded on the Company's Consolidated Balance Sheets, resulting in the change in fair value.

The above analysis of the derivative commodity instruments held by the Company does not include the offsetting impact that the same hypothetical price movement may have on the Company's physical sales of natural gas. The portfolio of derivative commodity instruments held to hedge the Company's forecasted produced gas approximates a portion of the Company's expected physical sales of natural gas. Therefore, an adverse impact to the fair value of the portfolio of derivative commodity instruments

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held to hedge the Company's forecasted production associated with the hypothetical changes in commodity prices referenced above should be offset by a favorable impact on the Company's physical sales of natural gas, assuming the derivative commodity instruments are not closed out in advance of their expected term, and the derivative commodity instruments continue to function effectively as hedges of the underlying risk.

If the underlying physical transactions or positions are liquidated prior to the maturity of the derivative commodity instruments, a loss on the financial instruments may occur or the derivative commodity instruments might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first.

Interest Rate Risk

Changes in interest rates affect the amount of interest the Company, EQGP and EQM earn on cash, cash equivalents and short-term investments and the interest rates the Company and EQM pay on borrowings under their respective revolving credit facilities. All of the Company's and EQM's long-term borrowings are fixed rate and thus do not expose the Company to fluctuations in its results of operations or liquidity from changes in market interest rates. Changes in interest rates do affect the fair value of the Company's and EQM's fixed rate debt. See Notes 13 and 14 to the Consolidated Financial Statements for further discussion of the Company's and EQM's borrowings and Note 7 to the Consolidated Financial Statements for a discussion of fair value measurements, including the fair value of long-term debt.

Other Market Risks

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company's over-the-counter (OTC) derivative instruments are primarily with financial institutions and, thus, are subject to events that would impact those companies individually as well as that industry as a whole. The Company utilizes various processes and analyses to monitor and evaluate its credit risk exposures. These include closely monitoring current market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, the Company enters into transactions with financial counterparties that are of investment grade, enters into netting agreements whenever possible and may obtain collateral or other security.

Approximately 11%, or $33.1 million, of the Company's OTC derivative contracts outstanding at December 31, 2016 had a positive fair value. Approximately 95%, or $417.4 million, of the Company's OTC derivative contracts outstanding at December 31, 2015 had a positive fair value. The decrease in derivative contracts with a positive fair value primarily relates to increased forward NYMEX prices as well as settlements of contracts during 2016 that had a positive fair value as of December 31, 2015.

As of December 31, 2016, the Company was not in default under any derivative contracts and had no knowledge of default by any counterparty to its derivative contracts. The Company made no adjustments to the fair value of derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in the Company's established fair value procedure. The Company monitors market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

The Company is also exposed to the risk of nonperformance by credit customers on physical sales or transportation of natural gas. A significant amount of revenues and related accounts receivable are generated from the sale of produced natural gas and NGLs to certain marketers, utility and industrial customers located mainly in the Appalachian Basin and the northeastern United States as well as the Permian Basin of Texas and a gas processor in Kentucky and West Virginia. The Company's current transportation portfolio also enables the Company to reach markets along the Gulf

Coast and Midwestern portions of the United States. Similarly, revenues and related accounts receivable are generated from the gathering, transmission and storage of natural gas in the Appalachian Basin for independent producers, local distribution companies and marketers.

The Company has a $1.5 billion revolving credit facility that expires in February 2019. The credit facility is underwritten by a syndicate of financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. As of December 31, 2016, the Company had no borrowings or letters of credit outstanding under the facility. No one lender of the large group of financial institutions in the syndicate holds more than 10% of the facility. The Company's large syndicate group and relatively low percentage of participation by each lender is expected to limit the Company's exposure to problems or consolidation in the banking industry.

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EQM has a $750 million revolving credit facility that expires in February 2019. The credit facility is underwritten by a syndicate of financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by EQM. As of December 31, 2016, EQM had no borrowings and no letters of credit outstanding under the credit facility. No one lender of the large group of financial institutions in the syndicate holds more than 10% of the facility. EQM's large syndicate group and relatively low percentage of participation by each lender is expected to limit EQM's exposure to problems or consolidation in the banking industry.

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Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
EQT Corporation

We have audited the accompanying consolidated balance sheets of EQT Corporation and Subsidiaries as of December 31, 2016 and 2015, and the related statements of consolidated operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2016. Our audits included the financial statement schedule listed in the Index at Item 15 (a). These financial statements and schedule are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of EQT Corporation and Subsidiaries at December 31, 2016 and 2015, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EQT Corporation and Subsidiaries’ internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 9, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania
February 9, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
EQT Corporation

We have audited EQT Corporation and Subsidiaries' internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). EQT Corporation and Subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, EQT Corporation and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of EQT Corporation and Subsidiaries as of December 31, 2016 and 2015, and the related statements of consolidated operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2016 and our report dated February 9, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania
February 9, 2017

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED OPERATIONS
YEARS ENDED DECEMBER 31,

	2016	2015	2014
	(Thousands except per share amounts)		
Revenues:			
Sales of natural gas, oil and NGLs	$1,594,997	$1,690,360	$2,132,409
Pipeline and net marketing services	262,342	263,640	256,359
(Loss) gain on derivatives not designated as hedges	(248,991)	385,762	80,942
Total operating revenues	1,608,348	2,339,762	2,469,710
Operating expenses:			
Transportation and processing	365,817	275,348	202,203
Operation and maintenance	73,266	69,760	54,528
Production	174,826	177,935	187,243
Exploration	13,410	61,970	21,716
Selling, general and administrative	272,747	249,925	238,134
Depreciation, depletion and amortization	927,920	819,216	679,298
Impairment of long-lived assets	66,687	122,469	267,339
Total operating expenses	1,894,673	1,776,623	1,650,461
Gain on sale / exchange of assets	8,025	—	34,146
Operating (loss) income	(278,300)	563,139	853,395
Other income	31,693	9,953	6,853
Interest expense	147,920	146,531	136,537
(Loss) income before income taxes	(394,527)	426,561	723,711
Income tax (benefit) expense	(263,464)	104,675	214,092
(Loss) income from continuing operations	(131,063)	321,886	509,619
Income from discontinued operations, net of tax	—	—	1,371
Net (loss) income	(131,063)	321,886	510,990
Less: Net income attributable to noncontrolling interests	321,920	236,715	124,025
Net (loss) income attributable to EQT Corporation	$(452,983)	$85,171	$386,965
Amounts attributable to EQT Corporation:			
(Loss) income from continuing operations	$(452,983)	$85,171	$385,594
Income from discontinued operations, net of tax	—	—	1,371
Net (loss) income	$(452,983)	$85,171	$386,965
Earnings per share of common stock attributable to EQT Corporation:			
Basic:			
Weighted average common stock outstanding	166,978	152,398	151,553
(Loss) income from continuing operations	$(2.71)	$0.56	$2.54
Income from discontinued operations, net of tax	—	—	0.01
Net (loss) income	$(2.71)	$0.56	$2.55
Diluted:			
Weighted average common stock outstanding	166,978	152,939	152,513

(Loss) income from continuing operations	$(2.71)	$0.56	$2.53
Income from discontinued operations, net of tax	—	—	0.01
Net (loss) income	$(2.71)	$0.56	$2.54

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
YEARS ENDED DECEMBER 31,

	2016	2015	2014
	(Thousands)		
Net (loss) income	$(131,063)	$321,886	$510,990
Other comprehensive (loss) income, net of tax:			
Net change in cash flow hedges:			
Natural gas, net of tax (benefit) expense of ($36,296), ($102,271) and $102,850	(55,155)	(152,359)	155,422
Interest rate, net of tax expense of $104, $100 and $104	144	144	145
Pension and other post-retirement benefits liability adjustment, net of tax expense (benefit) of $6,778, ($564) and ($515)	10,675	(901)	(776)
Other comprehensive (loss) income	(44,336)	(153,116)	154,791
Comprehensive (loss) income	(175,399)	168,770	665,781
Less: Comprehensive income attributable to noncontrolling interests	321,920	236,715	124,025
Comprehensive (loss) income attributable to EQT Corporation	$(497,319)	$(67,945)	$541,756

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS
YEARS ENDED DECEMBER 31,

	2016	2015	2014
	(Thousands)		
Cash flows from operating activities:			
Net (loss) income	$(131,063)	$321,886	$510,990
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Deferred income taxes	(180,261)	17,876	32,021
Depreciation, depletion and amortization	927,920	819,216	679,298
Asset and lease impairments and exploratory well costs	75,434	182,242	281,979
Gain on sale / exchange of assets	(8,025)	—	(34,146)
Gain on dispositions included in discontinued operations	—	—	(2,898)
Provision for (recoveries of) for losses on accounts receivable	3,856	(1,903)	88
Other income	(31,693)	(9,953)	(6,853)
Stock-based compensation expense	44,605	58,629	42,123
Gain recognized in operating revenues for hedging ineffectiveness	—	—	(24,774)
Loss (gain) on derivatives not designated as hedges	248,991	(385,762)	(80,942)
Cash settlements received on derivatives not designated as hedges	279,425	172,093	34,239
Pension settlement charge	9,403	—	—
Changes in other assets and liabilities:			
Dividend from Nora Gathering, LLC	—	—	9,463
Excess tax benefits on stock-based compensation	(1,148)	(22,945)	(33,216)
Accounts receivable	(165,507)	131,031	(70,392)
Accounts payable	40,548	(37,623)	30,350
Other items, net	(48,165)	(27,847)	47,412
Net cash provided by operating activities	1,064,320	1,216,940	1,414,742
Cash flows from investing activities:			
Capital expenditures	(1,539,494)	(2,434,018)	(2,277,306)
Capital expenditures for acquisitions	(1,051,239)	—	(174,184)
Investments in trading securities	(288,772)	—	—
Sales of investments in trading securities	3,890	—	—
Dry hole costs	—	(17,130)	(166)
Capital contributions to Mountain Valley Pipeline, LLC	(98,399)	(84,182)	—
Sales of interests in Mountain Valley Pipeline, LLC	12,533	9,723	—
Restricted cash, net	(75,000)	—	—
Proceeds from sale of assets	75,000	—	7,444
Net cash used in investing activities	(2,961,481)	(2,525,607)	(2,444,212)
Cash flows from financing activities:			
Proceeds from the issuance of common shares of EQT Corporation, net of issuance costs	1,225,999	—	—
Proceeds from the issuance of common units of EQT Midstream Partners, LP, net of issuance costs	217,102	1,182,002	902,467
Proceeds from the sale of common units of EQT GP Holdings, LP, net of issuance costs	—	673,964	—
Proceeds from issuance of EQT Midstream Partners, LP debt	500,000	—	500,000

Increase in borrowings on EQT Midstream Partners, LP credit facility	740,000	617,000	450,000
Repayment of borrowings on EQT Midstream Partners, LP credit facility	(1,039,000)	(318,000)	(450,000)
Dividends paid	(20,156)	(18,310)	(18,207)
Distributions to noncontrolling interests	(189,981)	(121,759)	(67,819)
Repayments and retirements of debt	(5,119)	(169,004)	(11,162)
Proceeds and excess tax benefits from awards under employee compensation plans	6,165	36,965	52,373
Cash paid for taxes related to net settlement of share-based incentive awards	(26,931)	(47,013)	(51,262)
Debt issuance costs and revolving credit facility origination fees	(8,580)	—	(12,764)
Repurchase of common stock	(30)	(3,375)	(32,368)
Net cash provided by financing activities	1,399,469	1,832,470	1,261,258
Net change in cash and cash equivalents	(497,692)	523,803	231,788
Cash and cash equivalents at beginning of year	1,601,232	1,077,429	845,641
Cash and cash equivalents at end of year	$1,103,540	$1,601,232	$1,077,429
Cash paid (received) during the year for:			
Interest, net of amount capitalized	$144,657	$147,550	$128,567
Income taxes, net	$(41,142)	$95,708	$204,818
Noncash activity during the year for:			
Increase in Mountain Valley Pipeline, LLC investment/payable for capital contributions	$11,471	$—	$—

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2016	2015
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$1,103,540	$1,601,232
Trading securities	286,396	—
Accounts receivable (less accumulated provision for doubtful accounts: $6,923 in 2016; $3,018 in 2015)	341,628	176,957
Derivative instruments, at fair value	33,053	417,397
Prepaid expenses and other	63,602	55,433
Total current assets	1,828,219	2,251,019
Property, plant and equipment	18,216,775	15,635,549
Less: accumulated depreciation and depletion	5,054,559	4,163,528
Net property, plant and equipment	13,162,216	11,472,021
Restricted cash	75,000	—
Investment in nonconsolidated entity	184,562	77,025
Other assets	222,925	176,107
Total assets	$15,472,922	$13,976,172

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EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2016	2015
	(Thousands)	
Liabilities and Shareholders' Equity		
Current liabilities:		
Credit facility borrowings	$—	$299,000
Accounts payable	309,978	291,550
Derivative instruments, at fair value	257,943	23,434
Other current liabilities	236,719	181,835
Total current liabilities	804,640	795,819
Long-term debt	3,289,459	2,793,343
Deferred income taxes	1,760,004	1,972,170
Other liabilities and credits	499,572	386,798
Total liabilities	6,353,675	5,948,130
Equity:		
Shareholders' equity		
Common stock, no par value, authorized 320,000 shares, shares issued: 177,896 in 2016 and 158,347 in 2015	3,440,185	2,153,280
Treasury stock, shares at cost: 5,069 in 2016 (including 226 held in rabbi trust) and 5,793 in 2015 (including 292 held in rabbi trust)	(91,019)	(104,079)
Retained earnings	2,509,073	2,982,212
Accumulated other comprehensive income	2,042	46,378
Total common shareholders' equity	5,860,281	5,077,791
Noncontrolling interests in consolidated subsidiaries	3,258,966	2,950,251
Total equity	9,119,247	8,028,042
Total liabilities and equity	$15,472,922	$13,976,172

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED EQUITY
YEARS ENDED DECEMBER 31, 2016, 2015 and 2014

	Common Stock					
	Shares Outstanding	No Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests in Consolidated Subsidiaries	Total Equity
			(Thousands)			
Balance, December 31, 2013	150,884	$1,422,105	$2,567,980	$ 44,703	$ 829,340	$4,864,128
Comprehensive income (net of tax):						
Net income			386,965		124,025	510,990
Net change in cash flow hedges:						
Natural gas, net of tax of $102,850				155,422		155,422
Interest rate, net of tax of $104				145		145
Pension and other post-retirement benefits liability adjustment, net of tax of ($515)				(776)		(776)
Dividends ($0.12 per share)			(18,207)			(18,207)
Stock-based compensation plans, net	1,012	56,846			2,235	59,081
Distributions to noncontrolling interests ($2.02 per common unit)					(67,819)	(67,819)
Issuance of common units of EQT Midstream Partners, LP					902,467	902,467
Repurchase and retirement of common stock	(300)	(12,759)	$(19,609)			(32,368)
Balance, December 31, 2014	151,596	$1,466,192	$2,917,129	$ 199,494	$ 1,790,248	$6,373,063
Comprehensive income (net of tax):						
Net income			85,171		236,715	321,886
Net change in cash flow hedges:						
Natural gas, net of tax of ($102,271)				(152,359)		(152,359)
Interest rate, net of tax of $100				144		144
Pension and other post-retirement benefits liability adjustment, net of tax of ($564)				(901)		(901)
Dividends ($0.12 per share)			(18,310)			(18,310)
Stock-based compensation plans, net	996	77,378			1,056	78,434
Distributions to noncontrolling interests ($2.505 and $0.15139 per common unit for EQT Midstream Partners, LP and EQT GP Holdings, LP, respectively)					(121,759)	(121,759)
Sale of common units of EQT GP Holdings, LP					673,964	673,964
Issuance of common units of EQT Midstream Partners, LP					1,182,002	1,182,002
Changes in ownership of consolidated subsidiaries		507,228			(811,975)	(304,747)

Repurchase and retirement of common stock	(38)	(1,597)	(1,778)			(3,375)
Balance, December 31, 2015	152,554	$2,049,201	$2,982,212	$ 46,378	$ 2,950,251	$8,028,042
Comprehensive income (net of tax):						
Net (loss) income			(452,983)		321,920	(131,063)
Net change in cash flow hedges:						
Natural gas, net of tax of ($36,296)				(55,155)		(55,155)
Interest rate, net of tax of $104				144		144
Pension and other post-retirement benefits liability adjustment, net of tax of $6,778				10,675		10,675
Dividends ($0.12 per share)			(20,156)			(20,156)
Stock-based compensation plans, net	724	42,782			161	42,943
Distributions to noncontrolling interests ($3.05 and $0.571 per common unit for EQT Midstream Partners, LP and EQT GP Holdings, LP, respectively)					(189,981)	(189,981)
Issuance of common shares of EQT Corporation	19,550	1,225,999				1,225,999
Issuance of common units of EQT Midstream Partners, LP					217,102	217,102
Elimination of net deferred taxes		5,921				5,921
Changes in ownership of consolidated subsidiaries		25,293			(40,487)	(15,194)
Repurchase and retirement of common stock	(1)	(30)				(30)
Balance, December 31, 2016	172,827	$3,349,166	$2,509,073	$ 2,042	$ 3,258,966	$9,119,247

Common shares authorized: 320,000 shares. Preferred shares authorized: 3,000 shares. There are no preferred shares issued or outstanding.

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2016

1. Summary of Significant Accounting Policies

Principles of Consolidation: The Consolidated Financial Statements include the accounts of EQT Corporation and all subsidiaries, ventures and partnerships in which a controlling interest is held (EQT or the Company). All significant intercompany accounts and transactions have been eliminated in consolidation. The results of EQT GP Holdings, LP (EQGP) and EQT Midstream Partners, LP (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.

Segments: Operating segments are revenue-producing components of the enterprise for which separate financial information is produced internally and which are subject to evaluation by the Company's chief operating decision maker in deciding how to allocate resources.

The Company reports its operations in three segments, which reflect its lines of business: EQT Production, EQT Gathering and EQT Transmission. The EQT Production segment includes the Company's exploration for, and development and production of, natural gas, natural gas liquids (NGLs) and a limited amount of crude oil, primarily in the Appalachian Basin. The EQT Production segment also includes the marketing activities of the Company. The operations of EQT Gathering include the natural gas gathering activities of the Company, consisting solely of assets that are owned and operated by EQM. The operations of EQT Transmission include the natural gas transmission and storage activities of the Company, consisting solely of assets that are owned and operated by EQM.

Prior to the October 2016 Sale (as defined in Note 4), 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.

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 an allocation of the headquarters' annual operating budget. Differences between budget and actual headquarters' expenses are not allocated to the operating segments.

Substantially all of the Company's operating revenues, income from operations and assets are generated or located in the United States.

Reclassification: Certain previously reported amounts have been reclassified to conform to the current year presentation under the current segment reporting structure.

Use of Estimates: The preparation of financial statements in conformity with United States generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and accompanying notes. Actual results could differ from those estimates.

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Cash Equivalents: The Company considers all highly liquid investments with an original maturity of three months or less when purchased to be cash equivalents. These investments are accounted for at cost. Interest earned on cash equivalents is included as a reduction of interest expense. As of December 31, 2016, the Company held two certificates of deposit (CDs) in denominations greater than $0.1 million with a aggregate carrying value of $300.0 million. These CDs matured in January 2017.

Trading Securities: Trading securities consist of liquid debt securities that are carried at fair value. Realized and unrealized gains and losses on these debt securities are included in Other Income in the Statements of Consolidated Operations. As of December 31, 2016, investments in trading securities had a fair value of $286.4 million. The Company recorded unrealized gains of $1.5 million for the year ended December 31, 2016 on the investments. The Company did not have any investments in trading securities as of December 31, 2015. The Company initiated its investments in trading securities in 2016 to enhance returns on a portion of its significant cash balance. Investments within the Company's portfolio are subject to a minimum credit rating based on type of investment, and the portfolio's asset mix is subject to exposure limits to ensure issuer and asset class diversification.

Restricted Cash: During 2016, the Company placed $75.0 million of the proceeds received from the sale of a gathering system (as described in Note 8) into restricted cash for the use of the funds in a potential like-kind exchange for tax purposes. Proceeds from potential like-kind exchanges are held by an intermediary and are classified as restricted cash as the funds must be reinvested in similar properties. If the acquisition of suitable like-kind properties is not completed within 180 days, the proceeds are distributed to the Company by the intermediary and are reclassified as available cash within the Consolidated Balance Sheets. The like-kind exchange was finalized in connection with the subsequent event on February 1, 2017 disclosed in Note 24.

Inventories: Generally, the Company’s inventory balance consists of natural gas stored underground or in pipelines and materials and supplies recorded at the lower of average cost or market. During the years ended December 31, 2016 and 2015, the Company recorded no lower of cost or market adjustments related to inventory. During the year ended December 31, 2014, the Company recorded losses for lower of cost or market adjustments of $3.2 million, which became part of the average cost of the inventory.

Property, Plant and Equipment: The Company’s property, plant and equipment consist of the following:

	As of December 31,	
	2016	2015
	(Thousands)	
Oil and gas producing properties, successful efforts method	$13,878,659	$11,816,769
Accumulated depreciation and depletion	(4,217,154)	(3,425,618)
Net oil and gas producing properties	9,661,505	8,391,151
Gathering assets	1,330,998	1,105,046
Accumulated depreciation and amortization	(110,473)	(88,918)
Net gathering assets	1,220,525	1,016,128
Transmission assets	1,563,860	1,257,270
Accumulated depreciation and amortization	(205,551)	(175,684)
Net transmission assets	1,358,309	1,081,586
Other properties, at cost less accumulated depreciation (a)	921,877	983,156
Net property, plant and equipment	$13,162,216	$11,472,021

(a) Other properties includes non-core gathering assets owned by EQT Production and shared assets held at Headquarters.

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, the cost of productive wells and related equipment, development dry holes, as well as productive acreage, including productive mineral interests, are capitalized and depleted using the unit-of-production method. These capitalized costs include salaries, benefits and other internal costs directly attributable to these activities. The Company capitalized internal costs of $115.4 million, $114.4 million and $108.5 million in 2016, 2015 and 2014, respectively, for production related activities. The Company also capitalized $19.2 million, $35.8 million and $35.0 million of interest expense related to Marcellus, Upper Devonian and Utica well development in 2016, 2015 and 2014, respectively. Depletion expense is calculated based on the actual produced sales volumes multiplied by the applicable depletion rate per unit. The depletion rates are derived by dividing the net capitalized costs by the number of units expected to be produced over the life of the reserves for lease costs and well costs separately. Costs of exploratory dry holes, exploratory geological and geophysical activities, delay rentals and other property carrying costs are charged to expense. The majority of the Company's producing oil and gas properties were depleted at an overall average rate of $1.06 per Mcfe, $1.18 per Mcfe and $1.22 per Mcfe for the years ended December 31, 2016, 2015 and 2014, respectively.

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The carrying values of the Company's proved oil and gas properties are reviewed for impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. In order to determine whether impairment has occurred, the Company estimates the expected future cash flows (on an undiscounted basis) from its oil and gas properties and compares these estimates to the carrying values of the properties. The estimated future cash flows used to test those 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 intended use of the asset, anticipated production from reserves, future market prices for natural gas, NGLs and oil, adjusted accordingly for basis differentials, future operating costs and inflation, some of which are interdependent. Proved oil and gas properties that have carrying amounts in excess of estimated future undiscounted cash flows are written down to fair value, which is estimated by discounting the estimated future cash flows using discount rate and other assumptions that marketplace participants would use in their estimates of fair value.

Due to the declines in commodity prices during 2016, 2015 and 2014, there were indications that the carrying values of certain of the Company's oil and gas producing properties may be impaired. The Company performed an undiscounted cash flow analysis for said properties and determined that no impairment existed during 2016. During 2015 and 2014, the undiscounted cash flows attributed to certain assets indicated that their carrying amounts were not expected to be fully recovered. As a result, the Company performed a discounted cash flow analysis and determined the fair value of the assets using an income approach based upon estimates of future production levels, commodity prices, operating costs and discount rates. The future production levels, future commodity prices, which were derived from the five-year forward price curve as adjusted for basis differentials and transportation costs, future operating costs, future inflation factors, as well as the assumed market participant discount rate, were considered to be significant unobservable inputs in the Company's calculation of fair value. As a result, valuation of the impaired assets was considered to be a Level 3 fair value measurement. For the years ended December 31, 2015 and 2014, EQT Production recognized pretax impairment charges on proved oil and gas properties of $98.6 million and $180.7 million, respectively, which are included in impairment of long-lived assets in the Statements of Consolidated Operations. The 2015 impairment included a charge of $94.3 million to record the proved properties in the Permian Basin of Texas at a fair value of $44.8 million and a charge of $4.3 million to record the proved properties in the Utica Shale of Ohio at a fair value of $5.7 million. After this charge to the Permian assets, the carrying value of Permian properties as of December 31, 2015 was approximately $345 million, including approximately $300 million of undeveloped properties. The 2014 impairment included charges of $105.2 million to record the proved properties in the Permian Basin of Texas at a fair value of $109.2 million and $75.5 million to record the proved properties in the Utica Shale of Ohio at a fair value of $7.4 million. The 2015 and 2014 impairments on proved properties in the Permian Basin of Texas were due to a decline in commodity prices. The 2015 and 2014 impairments in the Utica Shale of Ohio were a result of insufficient recovery of hydrocarbons to support continued development, along with the decline in commodity prices.

Capitalized costs of unproved oil and gas properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period in which that determination is made. For the years ended December 31, 2016, 2015 and 2014, EQT Production recorded unproved property impairments of $6.9 million, $19.7 million and $86.6 million, respectively, which are included in impairment of long-lived assets in the Statements of Consolidated Operations. The unproved property impairment in 2016 and 2015 related to leases not yet expired that would not be drilled prior to expiration. The unproved property impairment in 2014 related to the Company's decision to stop development of properties in its Utica Shale of Ohio. In addition, unproved lease expirations prior to drilling of $8.7 million, $37.4 million and $14.6 million are included in exploration expense of EQT Production for the years ended December 31, 2016, 2015 and 2014, respectively. Unproved properties had a net book value of $1,698.8 million and $898.3 million at December 31, 2016 and 2015, respectively.

At December 31, 2014, the Company had $9.0 million of capitalized exploratory well costs that were pending the determination of proved reserves. These exploratory well costs were reclassified to wells, equipment and facilities during the third quarter of 2015 upon the successful completion of the Company's first Utica well in Pennsylvania. During 2015, the Company drilled one exploratory dry hole within its non-core acreage and the related expenditures have been included within exploration expense in the Statements of Consolidated Operations as of December 31, 2015. There were no capitalized exploratory wells costs at December 31, 2015. At December 31, 2016, the Company had $5.1 million of capitalized exploratory well costs that were pending the determination of proved reserves.

EQT Gathering and EQT Transmission property, plant and equipment is carried at cost. Depreciation is calculated using the straight-line method based on estimated service lives. Midstream property consists largely of gathering and transmission systems (20 - 65 year estimated service life), buildings (35 year estimated service life), office equipment (3 - 7 year estimated service life), vehicles (5 year estimated service life), and computer and telecommunications equipment and systems (3 - 7 year estimated service life).

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Major maintenance projects that do not increase the overall life of the related assets are expensed. When major maintenance materially increases the life or value of the underlying asset, the cost is capitalized.

When events or changes in circumstances indicate that the carrying amount of any long-lived asset other than proved and unproved oil and gas properties may not be recoverable, the Company reviews its long-lived assets for impairment by first comparing the carrying value of the assets to the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the assets. If the carrying value exceeds the sum of the assets' undiscounted cash flows, the Company records an impairment loss equal to the difference between the carrying value and fair value of the assets. 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. Using the income approach and Level 3 fair value inputs, these gathering assets were written down to fair value. The impairment was triggered by a reduction in estimated future cash flows caused by the low commodity price environment and resulting reduced producer drilling activity and related throughput. During the year ended December 31, 2015, the Company recorded an impairment of long-lived assets of approximately $4.2 million related to an asset that will not be utilized in operations. No impairment of any long-lived asset other than proved and unproved oil and gas properties was recorded in 2014.

Sales and Retirements Policies: No gain or loss is recognized on the partial sale of proved developed oil and gas reserves unless non-recognition would significantly alter the relationship between capitalized costs and remaining proved reserves for the affected amortization base. When gain or loss is not recognized, the amortization base is reduced by the amount of the proceeds.

Regulatory Accounting: The regulated operations of EQT Transmission include interstate pipeline and storage operations subject to regulation by the Federal Energy Regulatory Commission (FERC). EQT Gathering's regulated operations include certain FERC-regulated gathering operations. The application of regulatory accounting allows the Company to defer expenses and income on its Consolidated Balance Sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the Statements of Consolidated Operations for a non-regulated company. The deferred regulatory assets and liabilities are then recognized in the Statements of Consolidated Operations in the period in which the same amounts are reflected in rates.

The following table presents the total regulated net revenues and operating expenses included in the operations of EQT Transmission and EQT Gathering:

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Net revenues	$347,320	$309,984	$267,997
Operating expenses	$118,611	$109,954	$89,617

The following table presents the regulated net property, plant and equipment included in EQT Transmission and EQT Gathering:

	As of December 31,	
	2016	2015
	(Thousands)	
Property, plant & equipment	$1,675,433	$1,356,206
Accumulated depreciation and amortization	(234,336)	(193,349)
Net property, plant & equipment	$1,441,097	$1,162,857

Regulatory assets associated with deferred taxes of $20.3 million and $73.1 million as of December 31, 2016 and 2015, respectively, are included in other assets in the Consolidated Balance Sheets and primarily represent deferred income taxes recoverable through future rates related to a historical deferred tax position and the equity component of allowance for funds used during construction (AFUDC). The Company expects to recover the amortization of the deferred tax position ratably over the corresponding life of the underlying assets that created the difference. The deferred tax regulatory asset associated with AFUDC represents the offset to the deferred taxes associated with the equity component of AFUDC of long-lived assets. Taxes on capitalized funds used during construction and the offsetting deferred income taxes will be collected through rates over the depreciable lives of the long-lived assets to which they relate.

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Derivative Instruments: Derivatives are held as part of a formally documented risk management program. The Company's use of derivative instruments is implemented under a set of policies approved by the Company's Hedge and Financial Risk Committee (HFRC) and reviewed by the Audit Committee of the Company's Board of Directors. The HFRC is composed of the chief executive officer, the president, the chief financial officer and other officers of the Company.

In regards to commodity price risk, the financial instruments currently utilized by the Company are primarily fixed price swap agreements and collar agreements. The Company engages in basis swaps to protect earnings from undue exposure to the risk of geographic disparities in commodity prices and interest rate swaps to hedge exposure to interest rate fluctuations on potential debt issuances. The Company also uses a limited number of other contractual agreements in implementing its commodity hedging strategy. The Company has an insignificant number of natural gas derivative instruments for trading purposes.

The accounting for the changes in fair value of the Company's derivative instruments depends on the use of the derivative instruments. To the extent that a derivative instrument had been designated and qualified as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of accumulated other comprehensive income
(OCI), net of tax, and is subsequently reclassified into the Statements of Consolidated Operations in the same period or periods during which the forecasted transaction is realized. The Company assesses the effectiveness of hedging relationships, as determined by the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, both at the inception of the hedge and on an on-going basis. If the gain (loss) for the hedging instrument is greater than the loss (gain) on the hedged item, the ineffective portion of the cash flow hedge is immediately recognized in operating revenues in the Statements of Consolidated Operations.

Effective December 31, 2014, the Company elected to de-designate all derivative commodity instruments that were designated and qualified as cash flow hedges. If a cash flow hedge was terminated or de-designated as a hedge before the settlement date of the hedged item, the amount of deferred gain or loss within accumulated OCI recorded up to that date remained deferred, provided that the forecasted transaction remained probable of occurring. Subsequent changes in fair value of a de-designated derivative instrument are recorded in earnings. The amount recorded in accumulated OCI is related to instruments that were designated as cash flow hedges. Since December 31, 2014, the Company has not designated any new derivative instruments as cash flow hedges.

Any changes in fair value of derivative instruments that have not been designated as hedges are recognized within operating revenues in the Statements of Consolidated Operations each period.

The Company reports all gains and losses on its natural gas derivative commodity instruments net as operating revenues on its Statements of Consolidated Operations.

AFUDC: Carrying costs for the construction of certain regulated assets are capitalized by the Company and amortized over the related assets' estimated useful lives. The capitalized amount includes interest cost (debt portion) and a designated cost of equity (equity portion) for financing the construction of these assets which are subject to regulation by the FERC.

The debt portion of AFUDC is calculated based on the average cost of debt and is included as a reduction of interest expense in the Statements of Consolidated Operations. AFUDC interest costs capitalized were $2.4 million, $1.6 million and $1.0 million for the years ended December 31, 2016, 2015 and 2014, respectively.

The equity portion of AFUDC is calculated using the most recent equity rate of return approved by the applicable regulator. Equity amounts capitalized are included in other income in the Statements of Consolidated Operations. The AFUDC equity amounts capitalized were $19.4 million, $6.3 million and $3.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

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Other Current Liabilities: Other current liabilities as of December 31, 2016 and 2015 are detailed below.

	December 31,	
	2016	2015
	(Thousands)	
Incentive compensation	$100,762	$73,014
Taxes other than income	56,874	44,925
Accrued interest payable	39,593	36,330
All other accrued liabilities	39,490	27,566
Total other current liabilities	$236,719	$181,835

Revenue Recognition: Revenue is recognized for production and gathering activities when deliveries of natural gas, NGLs and crude oil occur and title of the products is transferred to the buyer. Revenues from natural gas transmission and storage activities are recognized in the period the service is provided. Reservation revenues on firm contracted capacity are recognized over the contract period based on the contracted volume regardless of the amount of natural gas that is transported. The Company reports revenue from all energy trading contracts net in the Statements of Consolidated Operations, regardless of whether the contracts are physically or financially settled. Contracts which result in physical delivery of a commodity expected to be used or sold by the Company in the normal course of business are considered normal purchases and sales and are not subject to derivative accounting. Revenues from these contracts are recognized at contract value when delivered and are reported in operating revenues. The Company reports all gains and losses on its derivative commodity instruments net as operating revenues on its Statements of Consolidated Operations. The Company accounts for gas-balancing arrangements under the entitlement method. The Company uses the gross method to account for overhead cost reimbursements from joint operating partners. During periods in which rates are subject to refund as a result of a pending rate case, the Company records revenue at the rates which are pending approval but reserves these revenues to the level of previously approved rates until the final settlement of the rate case.

Investments in Consolidated Affiliates: In January 2015, the Company formed EQGP to own the Company's partnership interests in EQM. On May 15, 2015, EQGP completed an initial public offering (IPO) of 26,450,000 common units representing limited partner interests in EQGP, which represented 9.9% of EQGP's outstanding limited partner interests. The Company retained 239,715,000 common units, which represented a 90.1% limited partner interest, and the entire non-economic general partner interest, in EQGP. As of December 31, 2016, EQGP owned 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 incentive distribution rights (IDRs). EQGP and EQM are both consolidated in the Company's consolidated financial statements and the Company reports the noncontrolling interests of the public limited partners in its financial statements. See Notes 3 and 4.

Investments in Nonconsolidated Affiliates: Investments in companies in which the Company has the ability to exert significant influence over operating and financial policies (generally 20% to 50% ownership), but which the Company does not control, are accounted for using the equity method. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company evaluates its investments in nonconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When there is evidence of loss in value that is other than temporary, the Company compares the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss. See Note 11.

Unamortized Debt Discount and Issuance Expense: Discounts and expenses incurred with the issuance of long-term debt are amortized over the term of the debt. These amounts are presented as a reduction of long-term debt on the accompanying Consolidated Balance Sheets. See Note 14.

Transportation and Processing: Third-party costs incurred to gather, process and transport gas produced by EQT Production to market sales points are recorded as transportation and processing costs in the Statements of Consolidated Operations. The Company markets some transportation for resale. These costs, which are not incurred to transport gas produced by EQT Production, are reflected as a deduction from pipeline and net marketing services revenues.

Income Taxes: The Company files a consolidated federal income tax return and utilizes the asset and liability method to account for income taxes. The provision for income taxes represents amounts paid or estimated to be payable, net of amounts refunded or estimated to be refunded, for the current year and the change in deferred taxes, exclusive of amounts recorded in OCI.

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Any refinements to prior years' taxes made due to subsequent information are reflected as adjustments in the current period. Separate income taxes are calculated for income from continuing operations, income from discontinued operations and items charged or credited directly to shareholders' equity.

Deferred income tax assets and liabilities are determined based on temporary differences between the financial reporting and tax bases of assets and liabilities and are recognized using enacted tax rates for the effect of such temporary differences. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

In accounting for uncertainty in income taxes of a tax position taken or expected to be taken in a tax return, the Company utilizes a recognition threshold and measurement attribute for the financial statement recognition and measurement. The recognition threshold requires the Company to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position in order to record any financial statement benefit. If it is more likely than not that a tax position will be sustained, then the Company must measure the tax position to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income tax expense.

Provision for Doubtful Accounts: Judgment is required to assess the ultimate realization of the Company's accounts receivable, including assessing the probability of collection and the creditworthiness of certain customers. Reserves for uncollectible accounts are recorded as part of selling, general and administrative expense in the Statements of Consolidated Operations. The reserves are based on historical experience, current and expected economic trends and specific information about customer accounts.

Earnings Per Share (EPS): Basic EPS are computed by dividing net income attributable to EQT by the weighted average number of common shares outstanding during the period, without considering any dilutive items. Diluted EPS are computed by dividing net income attributable to EQT by the weighted average number of common shares and potentially dilutive securities, net of shares assumed to be repurchased using the treasury stock method. Purchases of treasury shares are calculated using the average share price for the Company's common stock during the period. Potentially dilutive securities arise from the assumed conversion of outstanding stock options and other share-based awards. See Note 17.

Asset Retirement Obligations: The Company accrues a liability for legal asset retirement obligations based on an estimate of the timing and amount of settlement. For oil and gas wells, the fair value of the Company's plugging and abandonment obligations is required to be recorded at the time the obligations are incurred, which is typically at the time the wells are spud. Upon initial recognition of an asset retirement obligation, the Company increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to depreciation, depletion and amortization, and the initial capitalized costs are depleted over the useful lives of the related assets.

Although individual assets will be replaced as needed, EQM's gathering system and transmission and storage system will continue to exist for an indefinite useful life. As such, there is uncertainty around the timing of any asset retirement activities. As a result, EQM determined that there is not sufficient information to make a reasonable estimate of the asset retirement obligations for the remaining assets as of December 31, 2016 and 2015.

The following table presents a reconciliation of the beginning and ending carrying amounts of the Company's asset retirement obligations which are included in other liabilities and credits in the Consolidated Balance Sheets. The Company does not have any assets that are legally restricted for purposes of settling these obligations.

	Years Ended December 31,	
	2016	2015
	(Thousands)	
Asset retirement obligation as of beginning of period	$ 168,142	$ 140,086
Accretion expense	9,696	10,646
Liabilities incurred	2,943	2,251
Liabilities settled	(1,484)	(5,027)
Change in estimates	64,303	20,186
Asset retirement obligation as of end of period	$ 243,600	$ 168,142

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During 2016, the Company had a change in estimates as a result of additional regulatory requirements for the plugging of conventional wells. The Company operates in several states that have recently implemented enhanced requirements that resulted in the use of additional materials during the plugging process and increased the estimated cost to plug these wells.

Self-Insurance: The Company is self-insured for certain losses related to workers' compensation and maintains a self-insured retention for general liability, automobile liability, environmental liability and other casualty coverage. The Company maintains stop loss coverage with third-party insurers to limit the total exposure for general liability, automobile liability, environmental liability and workers' compensation. The recorded reserves represent estimates of the ultimate cost of claims incurred as of the balance sheet date. The estimated liabilities are based on analyses of historical data and actuarial estimates and are not discounted. The liabilities are reviewed by management quarterly and by independent actuaries annually to ensure that they are appropriate. While the Company believes these estimates are reasonable based on the information available, financial results could be impacted if actual trends, including the severity or frequency of claims, differ from estimates.

Accumulated Other Comprehensive Income: The components of accumulated OCI, net of tax, are as follows:

	As of December 31,	
	2016	2015
	(Thousands)	
Net gain from natural gas hedging transactions	$9,607	$64,762
Net loss from interest rate swaps	(699)	(843)
Pension and other post-retirement benefits liability adjustment	(6,866)	(17,541)
Accumulated OCI	$2,042	$46,378

Noncontrolling Interests: Noncontrolling interests represent third-party equity ownership in EQGP and EQM and are presented as a component of equity in the Consolidated Balance Sheets. In the Statements of Consolidated Operations, noncontrolling interests reflect the allocation of earnings to third-party investors. See Notes 3 and 4 for further discussion of noncontrolling interests related to EQGP and EQM, respectively.

Recently Issued Accounting Standards: In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU is required to be adopted using one of two retrospective application methods. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers - Deferral of the Effective Date which approved a one year deferral of ASU 2014-09 for annual reporting periods beginning after December 15, 2017. The Company expects to adopt using the modified retrospective method of adoption on January 1, 2018. While the Company is currently evaluating the impact of this standard on individual customer contracts, the Company has evaluated the impact of this standard on the broad categories of its customer contracts, and the Company currently anticipates this standard will not have a material impact on net income within its financial statements.

In February 2015, the FASB issued ASU No. 2015-02, Consolidation. The standard changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. The Company adopted this standard in the first quarter of 2016 with no significant impact on reported results or disclosures. See Note 12.

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities. The changes promulgated by this standard primarily affect the accounting for equity investments and financial liabilities presented under the fair value option and the presentation and disclosure requirements for financial instruments. The ASU will be effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period, with early adoption of certain provisions permitted. The Company anticipates this standard will not have a material impact on its financial statements and related disclosures.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The ASU requires, among other things, that lessees recognize the following for all leases at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The ASU will be effective for annual reporting periods beginning after December 15, 2018, including interim periods within that reporting period, with early adoption permitted. While the Company is currently evaluating the provisions of

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this ASU to determine the impact this standard will have on its financial statements and related disclosures, the primary effect of adopting the new standard will be to record assets and obligations for contracts currently recognized as operating leases.

In March 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation: Improvements to Employee Share-Based Payment Accounting. This ASU is part of the FASB initiative to reduce complexity in accounting standards. The areas for simplification in this ASU involve several aspects of the accounting for employee share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The ASU will be effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with early adoption permitted. The Company anticipates this standard will not have a material impact on its financial statements and related disclosures.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and, instead, requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. The Company is currently evaluating the impact this standard will have on its financial statements and related disclosures.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments. This ASU addresses the presentation and classification of eight specific cash flow issues. The amendments in the ASU will be effective for public business entities for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted. The Company anticipates this standard will not have a material impact on its financial statements and related disclosures.

Subsequent Events: The Company has evaluated subsequent events through the date of the financial statement issuance.

2. Discontinued Operations

On December 17, 2013, the Company and its indirect wholly owned subsidiary Distribution Holdco, LLC completed the disposition of their ownership interests in Equitable Gas Company, LLC (Equitable Gas) and Equitable Homeworks, LLC (Homeworks) to PNG Companies LLC (the Equitable Gas Transaction). Equitable Gas and 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 for all periods presented in these financial statements.

During the year ended December 31, 2014, the Company received additional cash proceeds of $7.4 million as a result of post-closing purchase price adjustments for the Equitable Gas Transaction. As a result, the Company recognized an additional gain of $2.9 million for the year ended December 31, 2014, included in income from discontinued operations, net of tax, in the Statements of Consolidated Operations. As consideration for the Equitable Gas Transaction, the Company received total cash proceeds of $748.0 million, select midstream assets (including the Allegheny Valley Connector) with a fair value of $140.9 million and other contractual assets with a fair value of $32.5 million.

The following table summarizes the components of discontinued operations activity:

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Operating revenues	$ —	$ —	$ —
Income from discontinued operations before income taxes	—	—	2,377
Income taxes	—	—	1,006
Income from discontinued operations, net of tax	$ —	$ —	$ 1,371

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3. EQT GP Holdings, LP

In January 2015, the Company formed EQGP, a Delaware limited partnership, to own the Company's partnership interests in EQM. In April 2015, EQT Midstream Investments, LLC, an indirect wholly owned subsidiary of the Company that held EQT's EQM common units, merged with and into EQGP, and EQT Gathering Holdings, LLC (EQT Gathering Holdings), an indirect wholly owned subsidiary of EQT, contributed 100% of the outstanding limited liability company interests in EQT Midstream Services, LLC, EQM's general partner, to EQGP. As a result of these restructuring transactions, EQGP owned the following EQM partnership interests as of December 31, 2016, which represent EQGP's only cash-generating assets: 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 up to 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.

On May 15, 2015, EQGP completed an underwritten IPO of 26,450,000 common units representing limited partner interests in EQGP, which represented 9.9% of EQGP's outstanding limited partner interests. The Company retained 239,715,000 common units, which represented a 90.1% limited partner interest, and the entire non-economic general partner interest, in EQGP. EQT Gathering Holdings, as the selling unitholder, sold all of the EQGP common units in the offering, resulting in net proceeds to the Company of approximately $674.0 million after deducting the underwriters' discount of approximately $37.5 million and structuring fees of approximately $2.7 million. EQGP did not receive any of the proceeds from, or incur any expenses in connection with, EQGP's IPO. In connection with the EQGP IPO, the Company recorded a $320.4 million gain to additional paid-in-capital, a decrease in noncontrolling interest in consolidated subsidiary of $512.9 million and an increase to deferred tax liability of $192.5 million.

The Company continues to consolidate the results of EQGP, but records an income tax provision only as to its ownership percentage. The Company records the noncontrolling interest of the EQGP and EQM public limited partners (i.e., the EQGP limited partner interests not owned by the Company and the EQM limited partner interests not owned by EQGP) in its financial statements.

On January 19, 2017, the Board of Directors of EQGP's general partner declared a cash distribution to EQGP's unitholders for the fourth quarter of 2016 of $0.177 per common unit, or approximately $47.1 million. The distribution will be paid on February 23, 2017 to unitholders of record, including the Company, at the close of business on February 3, 2017.

4. EQT Midstream Partners, LP

In January 2012, the Company formed EQM to own, operate, acquire and develop midstream assets in the Appalachian Basin. EQM provides midstream services to the Company and other third parties. EQM is consolidated in the Company's financial statements. The Company records the noncontrolling interest of the EQM public limited partners in its financial statements.

In connection with EQM's IPO in July 2012, EQM issued 17,339,718 subordinated units of EQM to the Company. On February 17, 2015, the subordinated units converted into common units representing limited partner interests in EQM on a one-for-one basis as a result of satisfaction of certain conditions for termination of the subordination period set forth in EQM's partnership agreement.

EQM Equity Offerings: The following table summarizes EQM's public offerings of its common units during the three years ended December 31, 2016.

	Common Units Issued [a]	GP Units Issued [b]	Price Per Unit	Net Proceeds	Underwriters' Discount and Other Offering Expenses
	(Thousands, except unit and per unit amounts)				
May 2014 equity offering [c]	12,362,500	—	$75.75	$902,467	$ 33,992
March 2015 equity offering [d]	9,487,500	25,255	76.00	696,582	24,468
$750 million At the Market (ATM) Program in 2015 [e]	1,162,475	—	74.92	85,483	1,610
November 2015 equity offering [f]	5,650,000	—	71.80	399,937	5,733
$750 million ATM Program in 2016 [g]	2,949,309	—	$74.42	$217,102	$ 2,381

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(a) Includes the issuance of additional common units pursuant to the exercise of the underwriters' over-allotment options, as applicable.

(b) Represents general partner units issued to EQT Midstream Services, LLC, the general partner of EQM (the EQM General Partner), in exchange for its proportionate capital contribution.

(c) The net proceeds of the May 2014 equity offering were used by EQM to finance a portion of the cash consideration paid to EQT in connection with the Jupiter Transaction discussed below.

(d) The underwriters exercised their option to purchase additional common units. The EQM General Partner purchased 25,255 EQM general partner units for approximately $1.9 million to maintain its then 2.0% general partner ownership percentage. In connection with the offering, the Company recorded a $122.3 million gain to additional paid-in-capital, a decrease in noncontrolling interest in consolidated subsidiary of $195.8 million and an increase to deferred tax liability of $73.5 million. EQM used the proceeds from the offering to fund a portion of the purchase price for the NWV Gathering Transaction discussed below.

(e) In 2015, EQM entered into an equity distribution agreement that established an "At the Market" (ATM) common unit offering program, pursuant to which a group of managers, acting as EQM's sales agents, may sell EQM common units having an aggregate offering price of up to $750 million (the $750 million ATM Program). The price per unit represents an average price for all issuances under the $750 million ATM Program in 2015. The underwriters' discount and other offering expenses in the table include commissions of approximately $0.9 million and other offering expenses of approximately $0.7 million. In connection with the offerings, the Company recorded a $12.4 million gain to additional paid-in-capital, a decrease in noncontrolling interest in consolidated subsidiary of $19.8 million and an increase to deferred tax liability of $7.4 million. EQM used the net proceeds from the sales for general partnership purposes.

(f) EQM used the net proceeds for general partnership purposes and to repay amounts outstanding under EQM's credit facility. In connection with the offering, the Company recorded a $52.1 million gain to additional paid-in-capital, a decrease in noncontrolling interest in consolidated subsidiary of $83.5 million and an increase to deferred tax liability of $31.3 million.

(g) The price per unit represents an average price for all issuances under the $750 million ATM Program in 2016. The underwriters' discount and offering expenses in the table include commissions of approximately $2.2 million. In connection with these sales, the Company recorded a $24.9 million gain to additional paid-in-capital, a decrease in noncontrolling interest in consolidated subsidiary of $39.9 million and an increase to deferred tax liability of $15.0 million. EQM used the net proceeds for general partnership purposes.

Transactions between EQT and EQM: On May 7, 2014, EQT Gathering, LLC, an indirect wholly owned subsidiary of the Company, contributed the Jupiter gathering system to EQM in exchange for $1.18 billion (the Jupiter Transaction).

On March 17, 2015, the Company contributed the Northern West Virginia Marcellus gathering system to EQM in exchange for total consideration of $925.7 million (the NWV Gathering Transaction). On April 15, 2015, the Company transferred a preferred interest (the Preferred Interest) in EQT Energy Supply, LLC, an indirect subsidiary of the Company, to EQM in exchange for total consideration of $124.3 million. EQT Energy Supply, LLC generates revenue from services provided to a local distribution company.

On March 30, 2015, the Company assigned 100% of the membership interest in MVP Holdco, LLC (MVP Holdco), which at the time was its indirect wholly owned subsidiary, to EQM and received $54.2 million, which represented EQM's reimbursement to the Company for 100% of the capital contributions made by the Company to Mountain Valley Pipeline, LLC (MVP Joint Venture) as of March 30, 2015. As of February 9, 2017, EQM owned a 45.5% interest (the MVP Interest) in the MVP Joint Venture. The MVP Joint Venture plans to construct the Mountain Valley Pipeline (MVP), an estimated 300-mile natural gas interstate pipeline spanning from northern West Virginia to southern Virginia. The MVP Joint Venture has secured a total of 2.0 Bcf per day of 20-year firm capacity commitments, including a 1.29 Bcf per day firm capacity commitment by the Company. See Note 11.

On October 13, 2016, the Company entered into a Purchase and Sale Agreement with EQM pursuant to which EQM acquired from the Company (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 (collectively, the October 2016 Sale). The closing of the October 2016 Sale occurred on October 13, 2016 and was effective as of October 1, 2016. The aggregate consideration paid by EQM to the Company in connection with the October 2016 Sale was $275 million, which was funded with borrowings under EQM's $750 million revolving credit facility. Concurrent with the October 2016 Sale, the operating agreement of EQT Energy Supply, LLC was amended to include mandatory redemption of the Preferred Interest

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at the end of the preference period, which is expected to be December 31, 2034. As a result of this amendment, EQM's investment in EQT Energy Supply, LLC converted to a note receivable for accounting purposes effective October 13, 2016. The Company recorded an impairment of long-lived assets of approximately $59.7 million related to certain gathering assets sold to EQM in the October 2016 Sale. See Note 1.

EQM Borrowings: In August 2014, EQM issued 4.00% Senior Notes due 2024 (4.00% Senior Notes) in the aggregate principal amount of $500.0 million. The indenture governing the 4.00% Senior Notes contains covenants that limit EQM’s ability to, among other things, incur certain liens securing indebtedness, engage in certain sale and leaseback transactions, and enter into certain consolidations, mergers, conveyances, transfers or leases of all or substantially all of EQM’s assets.

On October 26, 2016, EQM entered into a $500 million, 364-day, uncommitted revolving loan agreement with EQT (the 364-Day Facility). The 364-Day Facility will mature on October 25, 2017 and will automatically renew for successive 364-day periods unless the Company delivers a non-renewal notice at least 60 days prior to the then current maturity date. EQM may terminate the 364-Day Facility at any time by repaying in full the unpaid principal amount of all loans together with interest thereon. The 364-Day Facility is available for general partnership purposes and does not contain any covenants other than the obligation to pay accrued interest on outstanding borrowings. Interest will accrue on any outstanding borrowings at an interest rate equal to the rate then applicable to similar loans under EQM's $750 Million revolving credit facility, or a successor revolving credit facility, less the sum of (i) the then applicable commitment fee under EQM's $750 Million revolving credit facility and (ii) 10 basis points. EQM had no borrowings outstanding under the 364-Day Facility as of December 31, 2016 or at any time during the year ended December 31, 2016.

In November 2016, EQM issued 4.125% Senior Notes due 2026 (the 4.125% Senior Notes) in the aggregate principal amount of $500 million. Net proceeds from the offering of $491.4 million were used to repay the outstanding borrowings under EQM’s credit facility and for general partnership purposes. The 4.125% Senior Notes contain covenants that limit EQM’s ability to, among other things, incur certain liens securing indebtedness, engage in certain sale and leaseback transactions, and enter into certain consolidations, mergers, conveyances, transfers or leases of all or substantially all of EQM’s assets.

On January 19, 2017, the Board of Directors of EQM’s general partner declared a cash distribution to EQM’s unitholders for the fourth quarter of 2016 of $0.85 per common unit. The cash distribution will be paid on February 14, 2017 to unitholders of record, including EQGP, at the close of business on February 3, 2017. Based on the 80,581,758 EQM common units outstanding on February 9, 2017, the aggregate cash distributions by EQM to EQGP will be approximately $47.9 million consisting of: $18.5 million in respect of its limited partner interest, $1.8 million in respect of its general partner interest and $27.6 million in respect of its IDRs.

5. Financial Information by Business Segment

Year Ended December 31, 2016	EQT Production	EQT Gathering	EQT Transmission	Intersegment Eliminations	EQT Corporation
	(Thousands)				
Revenues:					
Sales of natural gas, oil and NGLs	$1,594,997	$—	$—	$—	$1,594,997
Pipeline and marketing services	41,048	397,494	338,120	(514,320)	262,342
Loss on derivatives not designated as hedges	(248,991)	—	—	—	(248,991)
Total operating revenues	$1,387,054	$397,494	$338,120	$(514,320)	$1,608,348

Year Ended December 31, 2015

	EQT Production (Thousands)	EQT Gathering	EQT Transmission	Intersegment Eliminations	EQT Corporation
Revenues:					
Sales of natural gas, oil and NGLs	$1,690,360	$—	$ —	$—	$1,690,360
Pipeline and marketing services	55,542	335,105	297,831	(424,838)	263,640
Gain on derivatives not designated as hedges	385,762	—	—	—	385,762
Total operating revenues	$2,131,664	$335,105	$ 297,831	$(424,838)	$2,339,762

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Year Ended December 31, 2014	EQT Production (Thousands)	EQT Gathering	EQT Transmission	Intersegment Eliminations	EQT Corporation
Revenues:					
Sales of natural gas, oil and NGLs	$2,132,409	$—	$ —	$—	$2,132,409
Pipeline and marketing services	71,787	233,945	255,273	(304,646)	256,359
Gain on derivatives not designated as hedges	80,942	—	—	—	80,942
Total operating revenues	$2,285,138	$233,945	$ 255,273	$(304,646)	$2,469,710

	Years Ended December 31, 2016	2015 (Thousands)	2014
Operating (loss) income:			
EQT Production (a)	$(719,731)	$132,008	$556,918
EQT Gathering	289,027	243,257	147,426
EQT Transmission	237,922	207,779	185,169
Unallocated expenses (b)	(85,518)	(19,905)	(36,118)
Total operating (loss) income	$(278,300)	$563,139	$853,395
Reconciliation of operating (loss) income to (loss) income from continuing operations:			
Total operating (loss) income	$(278,300)	$563,139	$853,395
Other income	31,693	9,953	6,853
Interest expense	147,920	146,531	136,537
Income tax (benefit) expense	(263,464)	104,675	214,092
(Loss) income from continuing operations	$(131,063)	$321,886	$509,619

(a) Gains on sales / exchanges of assets of $8.0 million and $34.1 million are included in EQT Production operating income for 2016 and 2014, respectively. See Note 8. Impairment of long-lived assets of $6.9 million, $122.5 million and $267.3 million are included in EQT Production operating income for 2016, 2015 and 2014, respectively. See Note 1 for a discussion of impairment of long-lived assets.
(b) Unallocated expenses generally include incentive compensation expense and administrative costs. In addition, 2016 includes a $59.7 million impairment on gathering assets prior to the sale to EQM, and 2014 includes a $20.0 million contribution to the EQT Foundation.

	As of December 31, 2016 (Thousands)	2015	2014
Segment assets:			
EQT Production	$10,923,824	$9,905,344	$9,056,501
EQT Gathering	1,225,686	1,019,004	819,254
EQT Transmission	1,399,201	1,169,517	928,118
Total operating segments	13,548,711	12,093,865	10,803,873
Headquarters assets, including cash and short-term investments	1,924,211	1,882,307	1,231,480
Total assets	$15,472,922	$13,976,172	$12,035,353

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	Years Ended December 31,		
	2016	2015	2014
		(Thousands)	
Depreciation, depletion and amortization:			
EQT Production	$859,018	$765,298	$630,115
EQT Gathering	30,422	24,360	23,977
EQT Transmission	32,269	25,535	25,084
Other	6,211	4,023	122
Total	$927,920	$819,216	$679,298
Expenditures for segment assets: (c)			
EQT Production (d)	$2,073,907	$1,893,750	$2,505,365
EQT Gathering	295,315	225,537	253,638
EQT Transmission	292,049	203,706	137,317
Other	7,002	21,421	3,866
Total	$2,668,273	$2,344,414	$2,900,186

(c) Includes the capitalized portion of non-cash stock-based compensation costs, non-cash acquisitions and the impact of capital accruals. These non-cash items are excluded from capital expenditures on the statements of consolidated cash flows. The net impact of these non-cash items was $77 million, $(90) million and $448 million for the years ended December 31, 2016, 2015 and 2014, respectively. The impact of accrued capital expenditures includes the reversal of the prior period accrual as well as the current period estimate, both of which are non-cash items. The year ended December 31, 2016 included $87.6 million of non-cash capital expenditures related to acquisitions, and the year ended December 31, 2014 included $349.2 million of non-cash capital expenditures for the exchange of assets with Range Resources.

(d) Expenditures for segment assets in the EQT Production segment included $1,284.0 million, $182.3 million and $724.4 million for property acquisitions in 2016, 2015 and 2014, respectively. Included in the $1,284.0 million of property acquisitions for the year ended December 31, 2016 was $1,051.2 million of capital expenditures and $87.6 million of non-cash capital expenditures for acquisitions (see Note 9). Included in the $724.4 million of property acquisitions for the year ended December 31, 2014 was $349.2 million of non-cash capital expenditures for the exchange of assets with Range Resources (see Note 8).

6. Derivative Instruments

The Company's primary market risk exposure is the volatility of future prices for natural gas and NGLs, which can affect the operating results of the Company primarily at EQT Production. The Company's overall objective in its hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices.

The Company uses over the counter (OTC) derivative commodity instruments, primarily swap and collar agreements that are primarily placed with financial institutions. The creditworthiness of all counterparties is regularly monitored. Swap agreements involve payments to or receipts from counterparties based on the differential between two prices for the commodity. Collar agreements require the counterparty to pay the Company if the index price falls below the floor price and the Company to pay the counterparty if the index price rises above the cap price. The Company also sells call options that require the Company to pay the counterparty if the index price rises above the strike price. The Company engages in basis swaps to protect earnings from undue exposure to the risk of geographic disparities in commodity prices and interest rate swaps to hedge exposure to interest rate fluctuations on potential debt issuances. The Company has also engaged in a limited number of power-indexed natural gas sales and swaps that are accounted for as derivative commodity instruments.

The Company recognizes all derivative instruments as either assets or liabilities at fair value on a gross basis. These derivative instruments are reported as either current assets or current liabilities due to their highly liquid nature. The Company can net settle its derivative instruments at any time.

As a result of the discontinuance of cash flow hedge accounting, beginning in 2015, all changes in fair value of the Company's derivative instruments are recognized within operating revenues in the Statements of Consolidated Operations. In conjunction with the exchange of assets with Range Resources (see Note 8), the Company de-designated certain derivative instruments that were previously designated as cash flow hedges because it was probable that the forecasted transactions would not occur, resulting in a pre-tax gain of $28.0 million recorded within gain on sale / exchange of assets in the Statements of Consolidated Operations for the year ended December 31, 2014. Any subsequent changes in fair value of these derivative instruments are recognized within operating revenues in the Statements of Consolidated Operations each period.

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In prior periods, derivative commodity instruments used by the Company to hedge its exposure to variability in expected future cash flows associated with the fluctuations in the price of natural gas related to the Company's forecasted sales of EQT Production's produced volumes and forecasted natural gas purchases and sales were designated and qualified as cash flow hedges. Effective December 31, 2014, the Company elected to de-designate all cash flow hedges and discontinue the use of cash flow hedge accounting. As of December 31, 2016 and 2015, the forecasted transactions that were hedged as of December 31, 2014 remained probable of occurring and as such, the amounts in accumulated OCI will continue to be reported in accumulated OCI and will be reclassified into earnings in future periods when the underlying hedged transactions occur. The forecasted transactions extend through December 2018. As of December 31, 2016 and 2015, the Company deferred net gains of $9.6 million and $64.8 million, respectively, in accumulated OCI, net of tax, related to the effective portion of the change in fair value of its derivative commodity instruments designated as cash flow hedges. The Company estimates that approximately $4.9 million of net gains on its derivative commodity instruments reflected in accumulated OCI, net of tax, as of December 31, 2016 will be recognized in earnings during the next twelve months due to the settlement of hedged transactions.

Contracts which result in physical delivery of a commodity expected to be used or sold by the Company in the normal course of business are designated as normal purchases and sales and are exempt from derivative accounting.

OTC arrangements require settlement in cash. Settlements of derivative commodity instruments are reported as a component of cash flows from operations in the accompanying Statements of Consolidated Cash Flows.

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Commodity derivatives designated as cash flow hedges			
Amount of gain recognized in OCI (effective portion), net of tax	$—	$—	$156,207
Amount of gain reclassified from accumulated OCI, net of tax, into gain on sale / exchange of assets and dispositions due to forecasted transactions probable to not occur	—	—	16,735
Amount of gain (loss) reclassified from accumulated OCI, net of tax, into operating revenues (effective portion)	55,155	152,359	(15,950)
Amount of gain recognized in operating revenues (ineffective portion) (a)	—	—	24,774
Interest rate derivatives designated as cash flow hedges			
Amount of loss reclassified from accumulated OCI, net of tax, into interest expense (effective portion)	$(144)	$(144)	$(145)
Derivatives not designated as hedging instruments			
Amount of (loss) gain recognized in operating revenues	$(248,991)	$385,762	$80,942

(a) No amounts were excluded from effectiveness testing of cash flow hedges in 2014.

The absolute quantities of the Company's derivative commodity instruments totaled 703 Bcf and 676 Bcf as of December 31, 2016 and 2015, respectively, and were primarily related to natural gas swaps, basis swaps and collars. The open positions at December 31, 2016 and 2015 had maturities extending through December 2020 and 2019, respectively. The Company also had 1,095 Mbbls of propane swaps as of December 31, 2016, which had maturities extending through December 2018.

When the net fair value of any of the Company’s swap agreements represents a liability to the Company which is in excess of the agreed-upon threshold between the Company and the counterparty, the counterparty requires the Company to remit funds as a margin deposit for the derivative liability which is in excess of the threshold amount. The Company records these deposits as a current asset. When the net fair value of any of the Company’s swap agreements represents an asset to the Company which is in excess of the agreed-upon threshold between the Company and the counterparty, the Company requires the counterparty to remit funds as margin deposits in an amount equal to the portion of the derivative asset which is in excess of the threshold amount. The Company records a current liability for such amounts received. The Company had no such deposits in its Consolidated Balance Sheets as of December 31, 2016 or 2015.

The Company has netting agreements with financial institutions and its brokers that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities. The table below reflects the impact of netting agreements and margin deposits on gross derivative assets and liabilities as of December 31, 2016 and 2015.

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As of December 31, 2016	Derivative instruments, recorded in the Consolidated Balance Sheet, gross	Derivative instruments subject to master netting agreements	Margin deposits remitted to counterparties	Derivative instruments, net
	(Thousands)			
Asset derivatives:				
Derivative instruments, at fair value	$33,053	$(23,373)	$ —	$ 9,680
Liability derivatives:				
Derivative instruments, at fair value	$257,943	$(23,373)	$ —	$ 234,570

As of December 31, 2015	Derivative instruments, recorded in the Consolidated Balance Sheet, gross	Derivative instruments subject to master netting agreements	Margin deposits remitted to counterparties	Derivative instruments, net
	(Thousands)			
Asset derivatives:				
Derivative instruments, at fair value	$417,397	$(19,909)	$ —	$ 397,488
Liability derivatives:				
Derivative instruments, at fair value	$23,434	$(19,909)	$ —	$ 3,525

Certain of the Company's derivative instrument contracts provide that if the Company's credit ratings by Standard & Poor's Ratings Service (S&P) or Moody's Investors Service (Moody's) are lowered below investment grade, additional collateral must be deposited with the counterparty. The additional collateral can be up to 100% of the derivative liability. As of December 31, 2016, the aggregate fair value of all derivative instruments with credit risk-related contingent features that were in a net liability position was $236.5 million, for which the Company had no collateral posted on December 31, 2016. If the Company's credit rating by S&P or Moody's had been downgraded below investment grade on December 31, 2016, the Company would not have been required to post any additional collateral under the agreements with the respective counterparties. Investment grade refers to the quality of the Company's credit as assessed by one or more credit rating agencies. The Company's senior unsecured debt was rated BBB by S&P and Baa3 by Moody's at December 31, 2016. In order to be considered investment grade, the Company must be rated BBB- or higher by S&P and Baa3 or higher by Moody's. Anything below these ratings is considered non-investment grade. Having a non-investment grade rating would result in greater borrowing costs and collateral requirements than would be available if all credit ratings were investment grade.

7. Fair Value Measurements

The Company records its financial instruments, principally derivative instruments, at fair value in its Consolidated Balance Sheets. The Company estimates the fair value using quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use market-based parameters as inputs, including forward curves, discount rates, volatilities and nonperformance risk. Nonperformance risk considers the effect of the Company's credit standing on the fair value of liabilities and the effect of the counterparty's credit standing on the fair value of assets. The Company estimates nonperformance risk by analyzing publicly available market information, including a comparison of the yield on debt instruments with credit ratings similar to the Company's or counterparty's credit rating and the yield of a risk-free instrument and credit default swaps rates where available.

The Company has categorized its assets and liabilities recorded at fair value into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities in Level 2 primarily include the Company's swap and collar agreements.

The fair value of the commodity swaps included in Level 2 is based on standard industry income approach models that use significant observable inputs, including but not limited to New York Mercantile Exchange (NYMEX) forward curves, LIBOR-based discount rates, and basis forward curves. The Company's collars and options are valued using standard industry income approach option models. The significant observable inputs utilized by the option pricing models include NYMEX forward curves, natural gas volatilities and LIBOR-based discount rates. The NYMEX forward curves, LIBOR-based discount rates, natural gas volatilities, basis forward curves and propane forward curves are validated to external sources at least monthly.

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The following assets and liabilities were measured at fair value on a recurring basis during the applicable period:

Description	As of December 31, 2016	Fair value measurements at reporting date using Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(Thousands)			
Assets				
Trading securities	$286,396	$ —	$ 286,396	$ —
Derivative instruments, at fair value	$33,053	$ —	$ 33,053	$ —
Liabilities				
Derivative instruments, at fair value	$257,943	$ —	$ 257,943	$ —

Description	As of December 31, 2015	Fair value measurements at reporting date using Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(Thousands)			
Assets				
Trading securities	$—	$ —	$ —	$ —
Derivative instruments, at fair value	$417,397	$ —	$ 417,397	$ —
Liabilities				
Derivative instruments, at fair value	$23,434	$ —	$ 23,434	$ —

The carrying value of cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value due to the short-term maturity of the instruments. The carrying value of borrowings under EQM's $750 million credit facility approximates fair value as the interest rates are based on prevailing market rates.

The fair values of trading securities classified as Level 2 are priced using nonbinding market prices that are corroborated by observable market data. Inputs into these valuation techniques include actual trade data, broker/dealer quotes and other similar data. During 2016, the Company reflected its initial investment in trading securities as a Level 2 fair value measurement. The Company did not have any investments in trading securities as of December 31, 2015.

The Company estimates the fair value of its debt using its established fair value methodology. Because not all of the Company's debt is actively traded, the fair value of the debt is a Level 2 fair value measurement. Fair value for non-traded debt obligations is estimated using a standard industry income approach model which utilizes a discount rate based on market rates for debt with similar remaining time to maturity and credit risk. The estimated fair value of total debt (including EQM’s long-term debt) on the Consolidated Balance Sheets at December 31, 2016 and 2015 was approximately $3.5 billion and $2.8 billion, respectively. The carrying value of total debt (including EQM's long-term debt) on the Consolidated Balance Sheets at December 31, 2016 and 2015 was approximately $3.3 billion and $2.8 billion, respectively. Refer to Note 14 for further information regarding the Company's and EQM's debt as of December 31, 2016 and 2015.

The Company recognizes transfers between Levels as of the actual date of the event or change in circumstances that caused the transfer. There were no transfers between Levels 1, 2 and 3 during the periods presented.

For information on the fair values of assets related to the impairments of proved and unproved oil and gas properties and of other long-lived assets, the assets acquired in the Range Resources exchange, the assets acquired in acquisition transactions and the assets related to the defined benefit pension plan assets, see Notes 1, 8, 9 and 15.

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8. Sales/Exchanges of Assets

On December 17, 2013, the Company executed the Equitable Gas Transaction. Refer to Note 2 for additional information.

In June 2014, the Company exchanged certain assets with Range Resources Corporation (Range Resources). The Company received approximately 73,000 net acres and approximately 900 producing wells, most of which are vertical wells, in the Permian Basin of Texas. In exchange, Range Resources received approximately 138,000 net acres in the Company's Nora field of Virginia (Nora), the Company's working interest in approximately 2,000 producing vertical wells in Nora, the Company's 50% ownership interest in Nora Gathering, LLC (Nora LLC), which owns the supporting gathering system in Nora, and $167.3 million in cash. The Company previously recorded its 50% ownership interest in Nora LLC as a nonconsolidated investment in the Company's Consolidated Balance Sheets.

The fair value of the assets exchanged by the Company was approximately $516.5 million. Fair value of $318.3 million was allocated to the acquired acreage and $198.2 million was allocated to the acquired wells. The Company recorded a pre-tax gain of $34.1 million, which is included in gain on sale / exchange of assets in the Statements of Consolidated Operations. The gain on sale / exchange of assets included a $28.0 million pre-tax gain related to the de-designation of certain derivative instruments that were previously designated as cash flow hedges because it was probable that the forecasted transactions would not occur.

As the asset exchange qualified as a business combination under United States GAAP, the fair value of the acquired assets was determined using a discounted cash flow model under the market approach. The Company used estimated developed reserves, NYMEX forward pricing and comparable sales transactions as significant unobservable inputs in the analysis, which classify the acquired assets as a Level 3 measurement.

On December 28, 2016, the Company sold a gathering system that primarily gathered gas for third-parties for $75.0 million. In conjunction with this transaction, the Company realized a pre-tax gain of $8.0 million, which is included in gain on sale / exchange of assets in the Statements of Consolidated Operations.

9. Acquisitions

The Company executed multiple transactions during 2016 that resulted in the Company's acquisition of approximately 145,500 net Marcellus acres, including the transactions listed below through which 122,100 net Marcellus acres and 75 related Marcellus wells, 58 of which were producing, were acquired:

- On July 8, 2016, the Company acquired approximately 62,500 net Marcellus acres and 31 Marcellus wells, 24 of which were producing, from Statoil USA Onshore Properties, Inc. (the Statoil Acquisition). The net acres acquired are primarily located in Wetzel, Tyler and Harrison Counties, West Virginia.

- In the fourth quarter of 2016, the Company acquired approximately 42,600 Marcellus acres and 42 Marcellus wells, 32 of which are currently producing, which were being jointly developed by Trans Energy, Inc. (Trans Energy) and Republic Energy Ventures, LLC and its affiliates (collectively, Republic). The net acres acquired are primarily located in Wetzel, Marshall and Marion Counties, West Virginia. The acquisitions were effected through simultaneous transaction agreements that were executed on October 24, 2016 including: (i) a purchase and sale agreement between the Company and Republic; and (ii) an agreement and plan of merger among the Company, a wholly owned subsidiary of the Company (Merger Sub) and Trans Energy. The Republic acquisition closed on November 3, 2016 (the Republic Transaction). On October 27, 2016, the Company commenced a tender offer, through its wholly owned subsidiary, to acquire the outstanding shares of common stock of Trans Energy, a publicly traded company, at an offer price of $3.58 per share in cash. Following the tender offer on December 5, 2016, Merger Sub merged with and into Trans Energy, at which time Trans Energy became an indirect wholly owned subsidiary of the Company (the Trans Energy Merger).

- On December 16, 2016, the Company acquired approximately 17,000 net Marcellus acres located in Washington, Westmoreland and Greene Counties, Pennsylvania, and two related Marcellus wells that were producing (the Pennsylvania Acquisition).

In total, the Company paid $1,051.2 million in net cash in connection with the Statoil Acquisition, the Republic Acquisition, the Trans Energy Merger and the Pennsylvania Acquisition. The purchase prices remain subject to customary post-closing purchase price adjustments, which are the subject of active negotiations; thus, the purchase price adjustments included in the financial statements are preliminary as of December 31, 2016. Preliminary economic and post-closing adjustments are currently estimated to be a reduction to the aggregate purchase price of no greater than $30.0 million. The preliminary fair value assigned to the acquired property, plant and equipment as of the opening balance sheet dates totaled $1,138.8 million: $256.2 million allocated

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to the acquired producing wells and $882.6 million allocated to undeveloped leases. In connection with the Trans Energy Merger, the Company also acquired $1.2 million of other non-current assets and assumed $14.3 million of current liabilities and $11.1 million of non-current liabilities. The $14.3 million of current liabilities included a $5.1 million note payable; the Company repaid this note in 2016. The Company also recorded a deferred tax liability of $63.4 million due to differences in the tax and book basis of the acquired assets and liabilities.

Fair Value Measurement

As these acquisitions qualified as business combinations under GAAP, the fair value of the acquired assets was determined using a market approach for the undeveloped acreage and a discounted cash flow model under the income approach for the wells. Significant unobservable inputs used in the analysis included the determination of estimated developed reserves and NYMEX forward pricing; as a result, valuation of the acquired assets was a Level 3 measurement.

10. Income Taxes

Income tax (benefit) expense from continuing operations is summarized as follows:

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Current:			
Federal	$(82,905)	$85,696	$164,935
State	(298)	1,103	17,136
Subtotal	(83,203)	86,799	182,071
Deferred:			
Federal	(117,155)	(109,642)	38,357
State	(63,106)	127,518	(6,336)
Subtotal	(180,261)	17,876	32,021
Total income taxes	$(263,464)	$104,675	$214,092

The current federal income tax benefit in 2016 primarily related to amended return refund claims for open tax years 2010 through 2013. The current federal and state income tax expense in 2015 and 2014 primarily related to federal tax due to tax gains generated as a result of the net proceeds received from EQGP's IPO in 2015, the NWV Gathering Transaction in 2015 and the Jupiter Transaction in 2014.

The Protecting Americans from Tax Hikes (PATH) Act of 2015 was enacted on December 18, 2015 and retroactively and permanently extended the research and experimentation (R&E) tax credit for 2015 and forward. The PATH Act also reinstated and extended through the end of 2017 50% bonus depreciation phasing down to 40% in 2018 and 30% in 2019. The Tax Increase Prevention Act of 2014 was enacted on December 19, 2014, and it retroactively extended the R&E tax credit for 2014 and reinstated 50% bonus depreciation for property placed in service in 2014. The impact of these law changes has been reflected in the consolidated financial statements.

For federal income tax purposes, the Company may deduct a portion of drilling costs as intangible drilling costs (IDCs) in the year incurred which minimizes current taxes payable in periods of taxable income. IDCs, however, are sometimes limited for alternative minimum tax (AMT) purposes which can result in the Company paying AMT in periods where no other federal taxes are currently payable. The Company had no federal net operating loss carryforwards (NOLs) available as of December 31, 2015; however, due to the Trans Energy Merger discussed in Note 9, the Company acquired federal NOLs of which a nominal amount is available to be utilized annually over the next 20 years.

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Income tax expense differed from amounts computed at the federal statutory rate of 35% on pre-tax income as follows:

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Tax at statutory rate	$(138,084)	$149,296	$253,299
State income taxes	(71,613)	(7,566)	(2,992)
Valuation allowance	23,808	91,144	10,012
Noncontrolling partners’ share of EQGP and EQM earnings	(112,672)	(82,850)	(43,409)
Regulatory asset	35,438	(35,438)	—
Research and experimentation credit	(4,539)	(7,243)	(468)
Other	4,198	(2,668)	(2,350)
Income tax (benefit) expense	$(263,464)	$104,675	$214,092
Effective tax rate	66.8%	24.5%	29.6%

All of EQGP's income is included in the Company's pre-tax (loss) income. However, the Company is not required to record income tax expense with respect to the portion of EQGP's income allocated to the noncontrolling public limited partners of EQGP and EQM, which reduces the Company's effective tax rate in periods when the Company has consolidated pre-tax income and increases the Company's effective tax rate in periods when the Company has consolidated pre-tax loss.

The Company's effective tax rate for the year ended December 31, 2016 was 66.8% compared to 24.5% for the year ended December 31, 2015. The effective tax rate for the year ended December 31, 2016 was higher than the U.S. federal statutory rate of 35% primarily due to the effect of income allocated to the noncontrolling limited partners of EQGP and EQM. Due to the Company's consolidated pre-tax loss for the year ended December 31, 2016, EQGP's income allocated to noncontrolling limited partners increased the effective income tax rate for the year ended December 31, 2016. The increase in the effective income tax rate was also partly attributable to the tax benefit generated from pre-tax loss on state income tax paying entities and was partially offset by the $35.4 million regulatory asset write-off described in the following paragraphs.

The Company’s effective tax rate for the year ended December 31, 2015 was 24.5% compared to 29.6% for the year ended December 31, 2014. The decrease in the rate from 2014 to 2015 was primarily due to an increase in earnings allocated to noncontrolling limited partners of EQGP and EQM, the regulatory asset discussed in the following paragraph, a state income tax benefit as a result of lower pre-tax income on state income tax paying entities and increased tax credits recorded in 2015. These items were significantly offset by an increase in the valuation allowance recorded primarily on Pennsylvania state NOLs in 2015. Noncontrolling limited partners income increased in 2015 primarily as a result of higher net income at EQM and increased noncontrolling interests as a result of EQM’s March and November 2015 public offerings of common units, issuances of EQM common units under the $750 million ATM Program and EQGP’s IPO.

For the year ended December 31, 2015, the Company realized a $35.4 million regulatory asset tax benefit in connection with Internal Revenue Service (IRS) guidance received by the Company regarding a like-kind exchange of regulated assets which resulted in tax deferral for the Company. In order to be in compliance with the normalization rules of the Internal Revenue Code, the IRS guidance held that the deferred tax liability associated with the exchanged regulatory assets should not be considered for ratemaking purposes. As a result, during the second quarter of 2015, the Company recorded a regulatory asset equal to the taxes deferred from the exchange and an associated income tax benefit. The Company sold the assets on which it deferred the underlying taxes to EQM as part of the October 2016 Sale; as a result, the regulatory asset and deferred tax benefit reversed during the fourth quarter of 2016.

The Company believes that it is more likely than not that the benefit from certain state NOL carryforwards will not be realized. A valuation allowance is required when it is more likely than not that all or a portion of a deferred tax asset will not be realized. All available evidence, both positive and negative, must be considered in determining the need for a valuation allowance. At December 31, 2016, 2015 and 2014, positive evidence considered included financial and tax earnings generated over the preceding three years, reversals of financial to tax temporary differences, the implementation of and/or ability to employ various tax planning strategies and the estimation of future taxable income. Negative evidence considered included the current year pre-tax book loss and projection of low commodity prices generating pre-tax book losses in the near future. A review of positive and negative evidence regarding these tax benefits resulted in the conclusion that valuation allowances for certain Pennsylvania and Kentucky NOLs were warranted as it was more likely than not that the Company would not utilize some of the NOLs prior to expiration. Uncertainties such as future commodity prices can affect the Company's calculations and its ability to utilize these NOLs prior to expiration.

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The following table reconciles the beginning and ending amount of reserve for uncertain tax positions (excluding interest and penalties):

	2016	2015	2014
	(Thousands)		
Balance at January 1	$259,301	$56,957	$57,087
Additions based on tax positions related to current year	23,978	152,983	1,195
Additions for tax positions of prior years	20,336	50,688	93
Reductions for tax positions of prior years	(51,181)	(1,327)	(1,418)
Lapse of statute of limitations	—	—	—
Balance at December 31	$252,434	$259,301	$56,957

Included in the balance above are unrecognized tax benefits (excluding interest and penalties) that, if recognized, would affect the effective tax rate of $102.0 million, $94.1 million and $33.9 million as of December 31, 2016, 2015 and 2014, respectively. Additionally, there were uncertain tax positions of $75.4 million, $114.2 million, and $10.1 million for the years ended December 31, 2016, 2015 and 2014, respectively, that are included in the tabular reconciliation above, but recorded in the Consolidated Balance Sheets as a reduction of the related deferred tax asset for AMT credit carryforwards and NOLs.

Included in the tabular reconciliation above at December 31, 2016, 2015 and 2014 are $5.5 million, $6.4 million and $6.9 million, respectively, for tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of tax deductions. Due to the impact of deferred tax accounting, any disallowance of the shorter deductibility period would accelerate the payment of cash taxes to an earlier period but would not affect the Company's annual effective tax rate.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company recorded interest and penalties of approximately $1.6 million, $1.6 million and $1.9 million for 2016, 2015 and 2014, respectively. Interest and penalties of $5.2 million, $3.6 million and $2.0 million were included in the balance sheet reserve at December 31, 2016, 2015 and 2014, respectively.

As of December 31, 2016, the Company does not expect any of its unrecognized tax benefits to decrease within the next 12 months due to potential settlements with taxing authorities, legal or administrative guidance by relevant taxing authorities or the lapse of applicable statutes of limitation.

The consolidated federal income tax liability of the Company has been settled with the IRS through 2009. The IRS has completed its review of the 2010, 2011 and 2012 tax years and the Company is in the process of appealing its R&E tax credit claim for such years. In addition, the Company has filed refund claims relating to R&E and AMT preference adjustments for the years 2010 through 2013. These claims are under review by the IRS. The Company also is the subject of various state income tax examinations. With few exceptions, as of December 31, 2016, the Company is no longer subject to state examinations by tax authorities for years before 2012.

There were no material changes to the Company’s methodology for accounting for unrecognized tax benefits during 2016.

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The following table summarizes the source and tax effects of temporary differences between financial reporting and tax bases of assets and liabilities:

	As of December 31, 2016	2015
	(Thousands)	
Deferred income taxes:		
Total deferred income tax assets	$(875,407)	$(826,764)
Total deferred income tax liabilities	2,635,411	2,798,934
Total net deferred income tax liabilities	1,760,004	1,972,170
Total deferred income tax liabilities (assets):		
Drilling and development costs expensed for income tax reporting	1,473,459	1,473,551
Tax depreciation in excess of book depreciation	1,161,952	1,172,331
Incentive compensation and deferred compensation plans	(77,743)	(74,746)
Net operating loss carryforwards	(282,943)	(214,714)
Investment in EQGP and EQM	(386,676)	(426,343)
Alternative minimum tax credit carryforward	(224,428)	(267,045)
Unrealized hedge (losses) gains	(101,430)	107,854
Other	(3,609)	45,198
Total excluding valuation allowances	1,558,582	1,816,086
Valuation allowances	201,422	156,084
Total net deferred income tax liabilities	$1,760,004	$1,972,170

The Company is subject to the AMT if the computed AMT liability exceeds the regular tax liability for the year. As a result of certain AMT preference items related to IDCs, the Company has paid AMT and generated credit carryforwards. Because AMT taxes paid can be credited against regular tax and have an indefinite carryforward period, this item is reflected as a deferred tax asset on the Company's Consolidated Balance Sheets.

As of December 31, 2016, the Company had a deferred tax asset of $81.5 million, net of valuation allowances of $201.4 million, related to tax benefits from federal and state NOL carryforwards with various expiration dates ranging from 2018 to 2036. As of December 31, 2015, the Company had a deferred tax asset of $90.3 million, net of valuation allowances of $156.1 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2018 to 2035. The deferred tax asset was reduced for uncertain tax positions of approximately $0.5 million and $31.7 million during the years ended December 31, 2016 and 2015, respectively. Management will continue to assess the potential for realizing deferred tax assets based upon income forecast data and the feasibility of future tax planning strategies and may record adjustments to valuation allowances against deferred tax assets in future periods that could materially impact net income.

Historically, excess tax benefits were not recorded in the Company's financial statements as an addition to common shareholders' equity due to the Company's NOL position. The Company was in a breakeven taxable income position for the year ended December 31, 2016, but generated taxable income in the tax years ended December 31, 2015 and 2014. As a result, the Company recorded tax benefits of $0.9 million, $13.1 million, and $26.6 million as of December 31, 2016, 2015 and 2014, respectively, in the consolidated financial statements as additions to common shareholders' equity, which reduced taxes payable for each respective year. In 2015, the Company also recorded tax benefits of $8.1 million for 2012 excess tax benefits previously not recorded because the Company fully utilized the 2012 NOL during 2015. In 2014, the Company recorded tax benefits of $6.6 million for 2011 excess tax benefits previously not recorded because the Company fully utilized the 2011 NOL during 2014. The Company uses tax law ordering when determining when excess tax benefits have been realized.

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11. Equity in Nonconsolidated Investments

The Company, through its ownership interest in EQM, has an ownership interest in the MVP Joint Venture, a nonconsolidated investment that is accounted for under the equity method of accounting. The following table summarizes the Company's equity in the MVP Joint Venture:

Investees	Location	Interest Type	Ownership as of December 31, 2016	As of December 31, 2016	2015
				(Thousands)	
MVP Joint Venture	USA	Joint	45.5%	$ 184,562	$ 77,025

The Company’s ownership share of the earnings for 2016, 2015 and 2014 related to investments accounted for under the equity method was $9.9 million, $2.6 million and $3.4 million, respectively, reported in other income on the Statements of Consolidated Operations. For the years ended December 31, 2016 and 2015, the Company's ownership share of the earnings included equity earnings related to the Company's equity investment in the MVP Joint Venture. For the year ended December 31, 2014, the Company's ownership share of the earnings included equity earnings related to the Company's equity investment in Nora LLC. See Note 8 for further details regarding the Company's disposition of its interest in Nora LLC.

The MVP Joint Venture has been determined to be a variable interest entity because the MVP Joint Venture has insufficient equity to finance activities during the construction stage of the project. EQM is not the primary beneficiary because it does not have the power to direct the activities of the MVP Joint Venture that most significantly impact its economic performance. Certain business decisions, including, but not limited to, decisions with respect to operating and construction budgets, project construction schedule, material contracts or precedent agreements, indebtedness, significant acquisitions or dispositions, material regulatory filings and strategic decisions require the approval of owners holding more than a 66 2/3% interest in the MVP Joint Venture and no one member owns more than a 66 2/3% interest.

On January 21, 2016, affiliates of Consolidated Edison, Inc. (ConEd) acquired a 12.5% interest in the MVP Joint Venture and entered into 20-year firm capacity commitments for approximately 0.25 Bcf per day on both the MVP and EQM’s transmission system (the ConEd Transaction). As a result of the ConEd Transaction, EQM's interest in the MVP Joint Venture decreased by 8.5% to 45.5%, and ConEd reimbursed EQM $12.5 million, which represented EQM's proportional capital contributions to the MVP Joint Venture through the date of the transaction.

As of December 31, 2016, EQM had issued a $91 million performance guarantee in favor of the MVP Joint Venture to provide performance assurances for MVP Holdco's obligations to fund its proportionate share of the construction budget for the MVP. Upon the FERC’s initial release to begin construction of the MVP, EQM's guarantee will terminate; EQM will then be obligated to issue a new guarantee in an amount equal to 33% of MVP Holdco’s remaining obligations to make capital contributions to the MVP Joint Venture in connection with the then remaining construction budget, less, subject to certain limits, any credit assurances issued by any affiliate of EQM under such affiliate's precedent agreement with the MVP Joint Venture.

As of December 31, 2016, EQM's maximum financial statement exposure related to the MVP Joint Venture was approximately $275.6 million, which includes the investment balance of $184.6 million on the Consolidated Balance Sheet as of December 31, 2016 and amounts which could have become due under the performance guarantee as of that date.

12. Consolidated Variable Interest Entities

The Company adopted ASU No. 2015-02, Consolidation in the first quarter of 2016 and, as a result, EQT determined EQGP and EQM to be variable interest entities. Through EQT's ownership and control of EQGP's general partner and control of EQM's general partner, EQT has the power to direct the activities that most significantly impact their economic performance. In addition, through EQT's limited partner interest in EQGP and EQGP's general partner interest, limited partner interest and IDRs in EQM, EQT has the obligation to absorb the losses of EQGP and EQM and the right to receive benefits from EQGP and EQM, in accordance with such interests. As EQT has a controlling financial interest in EQGP and EQM, and is the primary beneficiary of EQGP and EQM, EQT consolidates EQGP and EQM.

The key risks associated with the operations of EQGP and EQM are:

- EQGP's only cash-generating assets consist of its partnership interests in EQM; therefore, its cash flow is dependent upon the ability of EQM to make cash distributions to its partners;
- EQM depends on EQT for a substantial majority of its revenues and future growth; therefore, EQM is indirectly subject to the business risks of EQT;

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- EQM's natural gas gathering, transmission and storage services are subject to extensive regulation by federal, state and local regulatory authorities and subject to stringent environmental laws and regulations, which may expose EQM to significant costs and liabilities;
- Certain of the services EQM provides on its transmission and storage system are subject to long-term, fixed-price "negotiated rate" contracts that are not subject to adjustment, even if EQM's cost to perform such services exceeds the revenues received from such contracts, and, as a result, EQM's costs could exceed its revenues received under such contracts; and
- Expanding EQM's business by constructing new midstream assets subjects EQM to risks. If EQM does not complete these expansion projects, its future growth may be limited.

See further discussion of the impact that EQT's involvement in EQGP and EQM have on EQT's financial position, results of operations and cash flows in Notes 3 and 4 for EQGP and EQM, respectively.

The following table presents amounts included in the Consolidated Balance Sheets that were for the use or obligation of EQGP or EQM as of December 31, 2016 and 2015.

Classification	December 31, 2016	December 31, 2015
	(Thousands)	
Assets:		
Cash and cash equivalents	$60,453	$360,957
Accounts receivable	20,662	17,790
Prepaid expenses and other	5,745	2,634
Property, plant and equipment, net	2,578,834	2,097,714
Other assets	206,104	149,871
Liabilities:		
Accounts payable	$35,831	$42,680
Credit facility borrowings	—	299,000
Other current liabilities	32,242	15,836
Long-term debt	985,732	493,401
Other liabilities and credits	9,562	91,933

The following table summarizes EQGP and EQM's Statements of Consolidated Operations and Cash Flows for the years ended December 31, 2016, 2015 and 2014 inclusive of affiliate amounts.

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Operating revenues	$735,614	$632,936	$489,218
Operating expenses	211,630	183,956	156,623
Other income (expenses)	11,010	(14,980)	(86,693)
Net income	$534,994	$434,000	$245,902
Net cash provided by operating activities	$535,357	$488,329	$324,837
Net cash used in investing activities	$(732,033)	$(1,043,822)	$(524,437)
Net cash (used in) provided by financing activities	$(103,828)	$735,712	$132,351

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13. Revolving Credit Facilities

The Company has a $1.5 billion unsecured revolving credit facility that expires in February 2019. The Company may request two one year extensions of the expiration date, the approval of which is subject to satisfaction of certain conditions.

The revolving credit facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes. Subject to certain terms and conditions, the Company may, on a one-time basis, request that the lenders' commitments be increased to an aggregate amount up to $2.0 billion. Each lender in the facility may decide if it will increase its commitment. The credit facility is underwritten by a syndicate of 18 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. The Company's obligations under the credit facility are unsecured. Interest rates are based on prevailing market rates.

The Company is not required to maintain compensating bank balances. The Company's debt issuer credit ratings, as determined by S&P, Moody's or Fitch Ratings Service (Fitch) on its non-credit-enhanced, senior unsecured long-term debt, determine the level of fees associated with its lines of credit in addition to the interest rate charged by the counterparties on any amounts borrowed against the lines of credit; the lower the Company's debt credit rating, the higher the level of fees and borrowing rate.

EQM has a $750 million credit facility that expires in February 2019. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions and repurchase units and for general partnership purposes. Subject to certain terms and conditions, EQM may request that the lenders' commitments be increased to an aggregate amount up to $1.0 billion. Each lender in the facility may decide if it will increase its commitment. The credit facility is underwritten by a syndicate of 18 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by EQM. The Company is not a guarantor of EQM's obligations under the credit facility. EQM's obligations under the revolving portion of the credit facility are unsecured. EQM's obligations under the credit facility were initially unconditionally guaranteed by each of EQM's subsidiaries. In January 2015, EQM amended its credit facility to, among other things, release its subsidiaries from their guarantee obligations under the credit facility.

EQM is not required to maintain compensating bank balances under its $750 million credit facility. EQM's debt issuer credit ratings, as determined by S&P, Moody's and Fitch on its non-credit-enhanced, senior unsecured long-term debt, determine the level of fees associated with its credit facility in addition to the interest rate charged by the counterparties on any amounts borrowed against the lines of credit; the lower EQM's debt credit rating, the higher the level of fees and borrowing rate.

The Company had no borrowings or letters of credit outstanding under its revolving credit facility as of December 31, 2016 or 2015 or at any time during the years ended December 31, 2016 or 2015. The Company incurred commitment fees averaging approximately 23 basis points for the years ended December 31, 2016 and 2015 to maintain credit availability under its credit facility.

As of December 31, 2016, EQM had no borrowings and no letters of credit outstanding under its revolving credit facility. As of December 31, 2015, EQM had $299 million of borrowings and no letters of credit outstanding under its revolving credit facility. The maximum amount of outstanding borrowings under EQM's revolving credit facility at any time during the years ended December 31, 2016 and 2015 was $401 million and $404 million, respectively. The average daily balance of loans outstanding under EQM's credit facility was $77 million and $261 million during the years ended December 31, 2016 and 2015, respectively. Interest was incurred on the borrowings at weighted average annual interest rates of approximately 2.0% and 1.7% for the years ended December 31, 2016 and 2015, respectively. EQM incurred commitment fees averaging approximately 23 basis points for each of the years ended December 31, 2016 and 2015 to maintain credit availability under its credit facility.

The Company's credit facility contains various provisions that, if not complied with, could result in termination of the credit facility, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the Company's credit facility relate to maintenance of a debt-to-total capitalization ratio and limitations on transactions with affiliates. The Company's credit facility contains financial covenants that require a total debt-to-total capitalization ratio of no greater than 65%. The calculation of this ratio excludes the effects of accumulated OCI. As of December 31, 2016, the Company was in compliance with all debt provisions and covenants.

EQM's credit facility contains various provisions that, if not complied with, could result in termination of the credit facility, require early payment of amounts outstanding or similar actions. The covenants and events of default under the credit facility relate to maintenance of permitted leverage ratio, limitations on transactions with affiliates, limitations on restricted payments, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of and certain other defaults under other financial obligations and change of control provisions. Under EQM's credit facility, EQM is required to maintain a consolidated

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leverage ratio of not more than 5.00 to 1.00 (or not more than 5.50 to 1.00 for certain measurement periods following the consummation of certain acquisitions). As of December 31, 2016, EQM was in compliance with all debt provisions and covenants.

See also the discussion of the revolving loan agreement between EQT and EQM in Note 4 to the Consolidated Financial Statements.

14. Long-Term Debt

	December 31, 2016			December 31, 2015		
	Principal Value	Carrying Value (a)	Fair Value (b)	Principal Value	Carrying Value (a)	Fair Value (b)
	(Thousands)					
5.15% notes, due March 1, 2018	$200,000	$199,545	$207,180	$200,000	$199,156	$203,490
6.50% notes, due April 1, 2018	500,000	499,089	527,205	500,000	498,360	520,175
8.13% notes, due June 1, 2019	700,000	698,106	789,271	700,000	697,295	760,837
4.88% notes, due November 15, 2021	750,000	743,595	801,218	750,000	742,270	728,063
4.00% EQM notes, due August 1, 2024	500,000	494,170	493,125	500,000	493,401	414,125
7.75% debentures, due July 15, 2026	115,000	110,235	141,800	115,000	109,738	119,372
4.125% EQM notes, due December 1, 2026	500,000	491,562	488,460	—	—	—
Medium-term notes:						
7.3% to 7.6% Series B, due 2015 through 2023	10,000	9,998	11,677	10,000	9,991	10,241
7.6% Series C, due 2018	8,000	7,991	8,375	8,000	7,983	8,366
8.7% to 9.0% Series A, due 2020 through 2021	35,200	35,168	41,906	35,200	35,149	38,598
	3,318,200	3,289,459	3,510,217	2,818,200	2,793,343	2,803,267
Less debt payable within one year	—	—	—	—	—	—
Total long-term debt	$3,318,200	$3,289,459	$3,510,217	$2,818,200	$2,793,343	$2,803,267

(a) Carrying value represents principal value less unamortized debt issuance costs and debt discounts.

(b) Fair value is measured using Level 2 inputs.

The indentures governing the Company's and EQM's long-term indebtedness contain certain restrictive financial and operating covenants, including covenants that restrict, among other things, the Company's or EQM's ability to incur, as applicable, indebtedness, incur liens, enter into sale and leaseback transactions, complete acquisitions, merge, sell assets and perform certain other corporate actions. The covenants do not contain a rating trigger. Therefore, a change in the Company's or EQM's debt rating would not trigger a default under the indentures governing the indebtedness.

Aggregate maturities of long-term debt are zero in 2017, $708.0 million in 2018, $700.0 million in 2019, $11.2 million in 2020, and $1,899.0 million in 2021 and thereafter.

15. Pension and Other Post-Retirement Benefit Plans

The Company, as sponsor of the EQT Corporation Retirement Plan for Employees (Retirement Plan), a defined benefit pension plan, terminated the Retirement Plan effective December 31, 2014. On March 2, 2016, the IRS issued a favorable determination letter for the termination of the Retirement Plan. On June 28, 2016, the Company purchased annuities from, and transferred the Retirement Plan assets and liabilities to, American General Life Insurance

Company. As a result, the Company reclassified the actuarial losses remaining in accumulated other comprehensive loss of approximately $9.4 million to earnings and approximately $5.1 million to a regulatory asset that will be amortized for rate recovery purposes over a period of 16 years. In connection with the purchase of annuities, the Company made a cash payment of approximately $5.4 million to fully fund the Retirement Plan upon liquidation during the second quarter of 2016.

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The following table sets forth the defined benefit pension and other post-retirement benefit plans' funded status and amounts recognized for those plans in the Company's Consolidated Balance Sheets.

	For the Years Ended December 31,			
	2016	2015	2016	2015
	Pension Benefits		Other Benefits	
	(Thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$23,045	$21,704	$17,635	$18,741
Service cost	175	350	764	762
Interest cost	242	746	663	634
Actuarial (gain) loss	(366)	2,770	(659)	(361)
Benefits paid	(1,600)	(1,981)	(2,217)	(2,141)
Expenses paid	(226)	(367)	—	—
Settlements	(21,270)	(177)	—	—
Benefit obligation at end of year	$—	$23,045	$16,186	$17,635
Change in plan assets:				
Fair value of plan assets at beginning of year	$16,941	$18,323	$1,110	$823
Actual gain (loss) on plan assets	776	(32)	—	—
Contributions	5,379	1,175	494	287
Benefits paid	(1,600)	(1,981)	—	—
Expenses paid	(226)	(367)	—	—
Settlements	(21,270)	(177)	—	—
Fair value of plan assets at end of year	—	16,941	1,604	1,110
Funded status at end of year	$—	$(6,104)	$(14,582)	$(16,525)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$—	$(6,104)	$(1,383)	$(1,376)
Noncurrent liabilities	—	—	(13,199)	(15,149)
Net amounts recognized	$—	$(6,104)	$(14,582)	$(16,525)
Amounts recognized in accumulated OCI, net of tax, consist of:				
Net loss	$—	$9,674	$6,636	$7,610
Net prior service	—	—	230	257
Net amount recognized	$—	$9,674	$6,866	$7,867

The Company uses a December 31 measurement date for its defined benefit pension and other post-retirement benefit plans.

The accumulated benefit obligation for the Retirement Plan was approximately $23.0 million at December 31, 2015. As the assets and liabilities of the Retirement Plan were transferred during 2016, the accumulated benefit obligation was zero at December 31, 2016.

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The Company's costs related to its defined benefit pension and other post-retirement benefit plans were as follows:

	For the Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
	Pension Benefits			Other Benefits		
	(Thousands)					
Components of net periodic benefit cost:						
Service cost	$175	$350	$350	$764	$762	$669
Interest cost	242	746	820	663	634	693
Expected return on plan assets	(287)	(627)	(1,377)	—	—	—
Amortization of prior service cost	—	—	—	(306)	(306)	(446)
Recognized net actuarial loss	423	746	709	703	793	879
Settlement loss and special termination benefits	14,685	122	879	—	—	—
Net periodic benefit cost	$15,238	$1,337	$1,381	$1,824	$1,883	$1,795

Currently, the Company recognizes expense for on-going post-retirement benefits other than pensions, a portion of which expense is subject to recovery in the approved rates of EQM's rate-regulated business.

	For the Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
	Pension Benefits			Other Benefits		
	(Thousands)					
Other changes in plan assets and benefit obligations recognized in OCI, net of tax:						
Net loss (gain)	$(9,674)	$1,592	$558	$(974)	$(663)	$39
Net prior service (credit) cost	—	—	—	(27)	(28)	179
Total recognized in OCI, net of tax	$(9,674)	$1,592	$558	$(1,001)	$(691)	$218
Total recognized in net periodic benefit cost and OCI, net of tax	$5,564	$2,929	$1,939	$823	$1,192	$2,013

The estimated net loss and net prior service (credit) for the other post-retirement benefit plans that will be amortized from accumulated OCI, net of tax, into net periodic benefit cost during 2017 are $0.4 million and $(0.2) million, respectively.

The following weighted average assumptions were used to determine the benefit obligations for the Company's defined benefit pension and other post-retirement benefit plans:

	December 31,			
	2016	2015	2016	2015
	Pension Benefits		Other Benefits	
Discount rate	N/A	2.20%	3.80%	3.95%
Rate of compensation increase	N/A	N/A	N/A	N/A

The following weighted average assumptions were used to determine the net periodic benefit cost for the Company's defined benefit pension and other post-retirement benefit plans:

	For the Years Ended December 31,			
	2016	2015	2016	2015
	Pension Benefits		Other Benefits	
Discount rate	2.20%	3.60%	3.95%	3.60%
Expected return on plan assets	3.75%	3.75%	N/A	N/A

Rate of compensation increase	N/A	N/A	N/A	N/A

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The expected rate of return on plan assets is established by the Company at the beginning of the fiscal year to which it relates based upon information available to the Company at that time, including the plans' investment mix and the historical and forecasted rates of return on the types of securities held. Any differences between actual experience and assumed (expected) experience are deferred as an unrecognized actuarial gain or loss. The unrecognized actuarial gains or losses are amortized into the Company's net periodic benefit cost. The expected rate of return on plan assets determined as of January 1, 2016 was 3.75%. This assumption was used to derive the Company's 2016 net periodic benefit cost. The rate of compensation increase is not applicable in determining future benefit obligations as a result of plan design.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits in 2016 was 6.75% for both the Pre-65 and Post-65 medical charges. The rates were assumed to decrease gradually to ultimate rates of 5.00% in 2025.

Assumed health care cost trend rates have an effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have had the following effects:

	One-Percentage-Point Increase			One-Percentage-Point Decrease		
	2016	2015	2014	2016	2015	2014
	(Thousands)					
Increase (decrease) to total of service and interest cost components	$16	$10	$13	$(18)	$(11)	$(14)
Increase (decrease) to post-retirement benefit obligation	$181	$268	$228	$(190)	$(278)	$(229)

The Company made cash contributions to the Retirement Plan of approximately $5.4 million, $1.2 million and $0.7 million during 2016, 2015 and 2014, respectively, to meet certain funding targets, including the termination funding. All assets of the Retirement Plan were liquidated and used to purchase annuities during 2016. The total cost of the annuities was approximately $21.3 million.

The following benefit payments for post-retirement benefits other than pensions, which reflect expected future service, are expected to be paid by the Company during each of the next five years and the five years thereafter: $1.7 million in 2017; $1.6 million in 2018; $1.6 million in 2019; $1.5 million in 2020; $1.5 million in 2021; and $6.8 million in the five years thereafter.

Expense recognized by the Company related to its defined contribution plan totaled $16.0 million in 2016, $15.7 million in 2015 and $13.7 million in 2014.

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16. Changes in Accumulated Other Comprehensive Income by Component

The following tables explain the changes in accumulated OCI by component for the years ended December 31, 2016, 2015, and 2014:

	Year Ended December 31, 2016			
	Natural gas cash flow hedges, net of tax	Interest rate cash flow hedges, net of tax	Pension and other post-retirement benefits liability adjustment, net of tax	Accumulated OCI (loss), net of tax
	(Thousands)			
Accumulated OCI (loss), net of tax, as of December 31, 2015	$64,762	$(843)	$(17,541)	$ 46,378
(Gains) losses reclassified from accumulated OCI, net of tax	(55,155) (a)	144 (a)	10,675 (b)	(44,336)
Accumulated OCI (loss), net of tax, as of December 31, 2016	$9,607	$(699)	$(6,866)	$ 2,042

	Year Ended December 31, 2015			
	Natural gas cash flow hedges, net of tax	Interest rate cash flow hedges, net of tax	Pension and other post-retirement benefits liability adjustment, net of tax	Accumulated OCI (loss), net of tax
	(Thousands)			
Accumulated OCI (loss), net of tax, as of December 31, 2014	$217,121	$(987)	$(16,640)	$ 199,494
(Gains) losses reclassified from accumulated OCI, net of tax	(152,359) (a)	144 (a)	(901) (b)	(153,116)
Accumulated OCI (loss), net of tax, as of December 31, 2015	$64,762	$(843)	$(17,541)	$ 46,378

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	Year Ended December 31, 2014							
	Natural gas cash flow hedges, net of tax		Interest rate cash flow hedges, net of tax		Pension and other post-retirement benefits liability adjustment, net of tax		Accumulated OCI (loss), net of tax	
	(Thousands)							
Accumulated OCI (loss), net of tax, as of December 31, 2013	$61,699		$(1,132)		$(15,864)		$ 44,703	
Gains recognized in accumulated OCI, net of tax	156,207	(a)	—		—		156,207	
Gain reclassified from accumulated OCI, net of tax, into gain on sale/exchange of assets	(16,735)	(a)	—		—		(16,735)	
Losses (gains) reclassified from accumulated OCI, net of tax	15,950	(a)	145	(a)	(776)	(b)	15,319	
Change in accumulated OCI, net of tax	155,422		145		(776)		154,791	
Accumulated OCI (loss), net of tax, as of December 31, 2014	$217,121		$(987)		$(16,640)		$ 199,494	

(a) See Note 6 for additional information.

(b) This accumulated OCI reclassification is attributable to the net actuarial loss and net prior service cost related to the Company's defined benefit pension plans and other post-retirement benefit plans. See Note 15 for additional information.

17. Common Stock, Treasury Stock and Earnings Per Share

Common Stock

At December 31, 2016, shares of EQT's authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	20,457
Stock compensation plans	11,401
Total	31,858

On February 19, 2016, the Company entered into an Underwriting Agreement with Goldman, Sachs & Co. (Goldman) under which the Company sold to Goldman 6,500,000 shares of common stock at a price to the public of $58.50 per share (the February Offering). On February 22, 2016, Goldman exercised its option within the Underwriting Agreement to purchase an additional 975,000 shares of common stock on the same terms. The February Offering closed on February 24, 2016, and the Company received net proceeds of approximately $430.4 million, after deducting underwriting discounts and commissions and offering expenses. The Company used the net proceeds from the February Offering for general corporate purposes.

On May 2, 2016, the Company entered into an Underwriting Agreement with Credit Suisse Securities (USA) LLC and J.P. Morgan Securities LLC, as representatives of the several underwriters named in the Underwriting Agreement (the Underwriters), under which the Company sold to the Underwriters 10,500,000 shares of common stock at a price to the public of $67.00 per share (the May Offering). On May 3, 2016, the Underwriters exercised their option within the Underwriting Agreement to purchase an additional 1,575,000 shares of common stock on the same terms. The May Offering closed on May 6, 2016, and the Company received net proceeds of approximately $795.6 million after deducting underwriting discounts and commissions and offering expenses. The Company used a portion of the net proceeds from the May Offering to fund the acquisitions discussed in Note 9, and intends to use the remainder for general corporate purposes.

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Treasury Stock

Effective as of December 31, 2015, the Company transferred 17.0 million shares of treasury stock from issued to authorized but unissued shares. Additionally, during the year ended December 31, 2015, the Company funded 291,919 shares of treasury stock into a rabbi trust for the 2005 Directors’ Deferred Compensation Plan and the 1999 Directors' Deferred Compensation Plan. As of December 31, 2016, there were 226,288 shares of treasury stock in the rabbi trust. Shares of the Company's common stock held by the rabbi trust are accounted for as treasury stock in the Company's financial statements.

Earnings Per Share

The computation of basic and diluted earnings per share of common stock attributable to EQT Corporation is shown in the table below:

	Years Ended December 31,		
	2016	2015	2014
	(Thousands except per share amounts)		
Basic earnings per common share:			
Net (loss) income attributable to EQT Corporation	$(452,983)	$85,171	$386,965
Average common shares outstanding	166,978	152,398	151,553
Basic earnings per common share	$(2.71)	$0.56	$2.55
Diluted earnings per common share:			
Net (loss) income attributable to EQT Corporation	$(452,983)	$85,171	$386,965
Average common shares outstanding	166,978	152,398	151,553
Potentially dilutive securities:			
Stock options and awards (a)	—	541	960
Total	166,978	152,939	152,513
Diluted (loss) earnings per common share	$(2.71)	$0.56	$2.54

(a) In periods when the Company reports a net loss, basic and diluted earnings per common share are equal because all options and restricted stock have an anti-dilutive effect on loss per share. As a result, basic shares equaled diluted shares for the year ended December 31, 2016 because the Company was in a net loss position. Options to purchase common stock which were excluded from potentially dilutive securities because they were anti-dilutive totaled 291,700 shares for the year ended December 31, 2015. No options to purchase common stock were excluded from potentially dilutive securities because they were anti-dilutive for the year ended December 31, 2014.

The impact of EQM’s and EQGP's dilutive units did not have a material impact on the Company’s earnings per share calculations for any of the periods presented.

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18. Share-Based Compensation Plans

Share-based compensation expense recorded by the Company was as follows:

	Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
2012 Executive Performance Incentive Program	$—	$—	$7,743
2013 Executive Performance Incentive Program	—	6,834	8,208
2014 Executive Performance Incentive Program	9,494	12,865	9,104
2015 Executive Performance Incentive Program	12,456	12,051	—
2016 Incentive Performance Share Unit Program	7,166	—	—
2013 EQT Value Driver Award Program	—	—	4,403
2014 EQT Value Driver Award Program	—	1,116	11,510
2014 EQM Value Driver Award Program	—	622	2,378
2015 EQT Value Driver Award Program	3,174	14,574	—
2016 EQT Value Driver Performance Share Unit Award Program	15,694	—	—
Restricted stock awards	9,407	7,031	4,688
Non-qualified stock options	3,119	1,938	3,002
Other programs, including non-employee director awards	5,459	(2,339)	(409)
Total share-based compensation expense	$65,969	$54,692	$50,627

A portion of the expense related to share-based compensation plans is included as an unallocated expense in deriving total operating income for segment reporting purposes. See Note 5. When an award has graduated vesting, the Company records expense equal to the vesting percentage on the vesting date.

The Company typically uses treasury stock to fund awards that are paid in stock, but the awards may be funded by stock acquired by the Company in the open market or from any other person, issued directly by the Company or any combination of the foregoing.

Cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2016, 2015 and 2014 was $5.0 million, $14.0 million and $19.2 million, respectively. During the years ended December 31, 2016, 2015 and 2014, share-based payment arrangements paid in stock generated tax benefits of $22.2 million, $43.1 million and $45.9 million, respectively.

Executive Performance Incentive Programs

The Management Development and Compensation Committee of the Company's Board of Directors (the Compensation Committee) adopted:

- the 2012 Executive Performance Incentive Plan (2012 Incentive PSU Program) under the 2009 Long-Term Incentive Plan (2009 LTIP);
- the 2013 Executive Performance Incentive Plan (2013 Incentive PSU Program) under the 2009 LTIP;
- the 2014 Executive Performance Incentive Plan (2014 Incentive PSU Program) under the 2009 LTIP;
- the 2015 Executive Performance Incentive Plan (2015 Incentive PSU Program) under the 2014 Long-Term Incentive Plan (2014 LTIP); and
- the 2016 Incentive Performance Share Unit Program (2016 Incentive PSU Program) under the 2014 LTIP.

The 2012 Incentive PSU Program, the 2013 Incentive PSU Program, the 2014 Incentive PSU Program, the 2015 Incentive PSU Program, and the 2016 Incentive PSU Program are collectively referred to as the Incentive PSU Programs.

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The Incentive PSU Programs were established to provide long-term incentive opportunities to key employees to further align their interests with those of the Company's shareholders and with the strategic objectives of the Company. The performance period for each of the awards under the Incentive PSU Programs is 36 months, with vesting occurring upon payment following the expiration of the performance period. Awards granted were/will be earned based upon:

- the level of total shareholder return relative to a predefined peer group; and
- with respect to the 2012 Incentive PSU Program and the 2013 Incentive PSU Program, the level of cumulative operating cash flow per share, and with respect to the other Incentive PSU Programs, the cumulative total sales volume growth, in each case, over the performance period.

The payout factor varies between zero and 300% of the number of outstanding units contingent upon the performance metrics listed above. The Company accounted for these awards as equity awards using a grant date fair value determined through a Monte Carlo simulation which projected the share price for the Company and its peers at the ending point of the performance period. The expected share prices were generated using each company's annual volatility for the expected term and the commensurate three-year risk-free rate shown in the chart below. As the Incentive PSU Programs include a performance condition that affects the number of shares that will ultimately vest (the level of cumulative operating cash flow per share with respect to the 2012 Incentive PSU Program and the 2013 Incentive PSU Program and the cumulative total sales volume growth performance condition with respect to the other Incentive PSU Programs), in accordance with ASC Topic 718, the Monte Carlo simulation computed the grant date fair value for each possible performance condition outcome on the grant date. The Company reevaluates the then-probable outcome at the end of each reporting period, in order to record expense at the probable outcome grant date fair value. The vesting of the units under each Incentive PSU Program occurs upon payment after the end of the performance period. More detailed information about each award is set forth in the table below:

Incentive PSU Program	Grant Date Fair Value[1]	Risk Free Rate	Vested/Payment Date	Awards Paid	Value (in millions)	Unvested/Expected Payment Date[2]	Awards Outstanding as of December 31, 2016[3]
2012	$123.37	0.36%	February 2015	307,323	$ 37.9	N/A	N/A
2013	$140.00	0.36%	February 2016	261,073	$ 36.6	N/A	N/A
2014[4]	$189.68	0.78%	N/A	N/A	N/A	First Quarter of 2017	238,060
2015[5]	$160.13	1.10%	N/A	N/A	N/A	First Quarter of 2018	341,103
2016[6]	$70.60	1.31%	N/A	N/A	N/A	First Quarter of 2019	482,030

[1] Grant date fair value determined using a Monte Carlo simulation. For unvested Incentive PSU Programs the grant date fair value is as of December 31, 2016. The Company recorded compensation expense as of December 31, 2016 using the grant date fair value computed for the outcome which management estimated to be most probable.
[2] Vesting of the units will occur upon payment, following the expiration of the performance period.
[3] Represents the number of outstanding units as of December 31, 2016 adjusted for forfeitures.
[4] Based on the Company's performance relative to the conditions discussed above, 238,060 shares of common stock, valued at $45.2 million using the grant date fair value, are expected to be distributed during the first quarter of 2017.
[5] As of January 1, 2016, a total of 356,400 units were outstanding under the 2015 Incentive PSU Program. Adjusting for 15,297 forfeitures, there were 341,103 outstanding units as of December 31, 2016.
[6] A total of 504,240 units were granted under the 2016 Incentive PSU Program in 2016 and no additional units may be granted. Adjusting for 22,210 forfeitures, there were 482,030 outstanding units as of December 31, 2016.

The following table sets forth the total compensation costs capitalized related to each of the Incentive PSU Programs:

Award	For the Years Ended December 31, (millions)		
	2016	2015	2014
2012 Incentive PSU Program	$—	$—	$2.6
2013 Incentive PSU Program	$—	$4.4	$5.5
2014 Incentive PSU Program	$4.2	$4.9	$4.6
2015 Incentive PSU Program	$4.9	$4.9	$—
2016 Incentive PSU Program	$3.3	$—	$—

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As of December 31, 2016, $16.5 million and $20.2 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2015 Incentive PSU Program and the 2016 Incentive PSU Program, respectively, was expected to be realized over the remainder of the performance periods.

Value Driver Award Programs

The Compensation Committee has also adopted:
- the 2013 Value Driver Award Program (2013 EQT VDPSU Program) under the 2009 LTIP;
- the 2014 Value Driver Award Program (2014 EQT VDPSU Program) under the 2009 LTIP;
- the 2015 Value Driver Award Program (2015 EQT VDPSU Program) under the 2014 LTIP; and
- the 2016 Value Driver Performance Share Unit Award Program (2016 EQT VDPSU Program) under the 2014 LTIP.

The 2013 EQT VDPSU Program, the 2014 EQT VDPSU Program, the 2015 EQT VDPSU Program and the 2016 EQT VDPSU Program are collectively referred to as the VDPSU Programs.

The VDPSU Programs were established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under each VDPSU Program, 50% of the awards confirmed vest upon payment following the first anniversary of the grant date; the remaining 50% of the awards confirmed vest upon payment following the second anniversary of the grant date. Due to the graded vesting of each award under the VDPSU Programs, the Company recognized compensation cost over the requisite service period for each separately vesting tranche of the award as though each award was, in substance, multiple awards. The payments are contingent upon adjusted earnings before interest, income taxes, depreciation and amortization performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the respective one-year periods. More detailed information about each award is set forth in the table below:

EQT VDPSU Program	Settled In	Accounting Treatment	Fair Value per Unit[1]	Vested/Payment Date	Number of awards (including accrued dividends) or cash (millions) paid	Unvested/Expected Payment Date	Awards Outstanding (including accrued dividends) as of December 31, 2016[2]
2013	Stock	Equity	$ 58.98	February 2014 February 2015	306,076 279,475	N/A	N/A
2014	Cash	Liability	$ 75.70 $ 52.13	February 2015 February 2016	$ 14.2 $ 9.4	N/A	N/A
2015[3]	Stock	Equity	$ 75.70	February 2016	222,751	Second tranche first quarter of 2017	208,734
2016[4]	Cash	Liability	$ 65.40	N/A	N/A	First tranche first quarter of 2017	325,664
			N/A	N/A	N/A	Second tranche first quarter of 2018	325,664

[1] For equity awards, the fair value per unit is equal to the Company's closing common stock price on the business day prior to the

grant date. For liability awards, the fair value per unit is equal to the Company's common stock price on the measurement date.

[2] As of January 1, 2016, 448,487 awards including accrued dividends were outstanding under the 2015 EQT VDPSU Program.

[3] In addition to the 222,751 awards paid in February 2016, 6,631 awards were paid in 2016 in accordance with the employee separation agreements.

[4] The total liability recorded for the 2016 EQT VDPSU Program was $31.9 million as of December 31, 2016.

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The following table sets forth the total compensation costs capitalized related to each of the VDPSU Programs:

Award	For the Years Ended December 31, (millions) 2016	2015	2014
2013 EQT VDPSU Program	$—	$—	$2.9
2014 EQT VDPSU Program	$—	$1.3	$9.8
2015 EQT VDPSU Program	$4.1	$10.9	$—
2016 EQT VDPSU Program	$16.3	$—	$—

Restricted Stock Awards - Equity

The Company granted 158,360 and 89,500 restricted stock equity awards during the years ended December 31, 2015 and 2014, respectively, to key employees of the Company. The restricted stock granted will be fully vested at the end of the three-year period commencing with the date of grant, assuming continued service. The weighted average fair value of these restricted stock grants, based on the grant date fair value of the Company's common stock, was approximately $75 and $95 for the years ended December 31, 2015 and 2014, respectively.

The Company granted 7,900 restricted stock equity awards during the year ended December 31, 2016 to its new Chief Financial Officer. The restricted shares granted will be fully vested at the end of the one-year period commencing on the date of grant, assuming continued service. The fair value of this restricted stock grant, based on the Company's closing common stock price on the grant date, is $63.33 per share.

The total fair value of restricted stock awards vested during the years ended December 31, 2016, 2015 and 2014 was $5.1 million, $3.8 million and $1.5 million, respectively.

As of December 31, 2016, $5.9 million of unrecognized compensation cost related to nonvested restricted stock equity awards was expected to be recognized over a remaining weighted average vesting term of approximately 1.0 years.

A summary of restricted stock equity award activity as of December 31, 2016, and changes during the year then ended, is presented below:

Restricted Stock	Non-Vested Shares	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at January 1, 2016	300,120	$ 79.90	$23,980,627
Granted	7,900	$ 63.33	500,307
Vested	(69,880)	$ 72.76	(5,084,759)
Forfeited	(13,800)	$ 78.74	(1,086,637)
Outstanding at December 31, 2016	224,340	$ 81.61	$18,309,538

Restricted Stock Unit Awards - Liability

The Company granted 148,860 restricted stock unit liability awards that will be paid in cash during the year ended December 31, 2016 to key employees of the Company. There were no restricted stock unit liability awards outstanding as of December 31, 2015. Adjusting for forfeitures, there were 141,490 awards outstanding as of December 31, 2016. Because these awards are liability awards, the Company records compensation expense based upon of the fair value of the awards as remeasured at the end of each reporting period. The restricted units granted will be fully vested at the end of the three-year period commencing with the date of grant, assuming continued service. The total liability recorded for these restricted units was $2.7 million as of December 31, 2016.

Non-Qualified Stock Options

The fair value of the Company's option grants was estimated at the dates of grant using a Black-Scholes option-pricing model with the assumptions indicated in the table below for the years ended December 31, 2016, 2015 and 2014. The risk-free

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rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the date of grant. The dividend yield is based on the dividend yield of the Company's common stock at the time of grant. Expected volatilities are based on historical volatility of the Company's common stock. The expected term represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

	For the Years Ended December 31,		
	2016 [1]	2015	2014
Risk-free interest rate	1.67 %	1.61 %	1.72 %
Dividend yield	0.16 %	0.12 %	0.15 %
Volatility factor	28.59 %	26.80 %	24.80 %
Expected term	5 years	5 years	5 years

	For the Years Ended December 31,		
	2016 [1]	2015	2014
Number of Options Granted	228,500	158,200	133,500
Weighted Average Grant Date Fair Value	$ 15.10	$ 19.90	$ 22.25
Total Intrinsic Value of Options Exercised (millions)	$ 3.5	$ 15.1	$ 14.4

[1] There were two grant dates for the 2016 options. Amounts represent weighted average.

As of December 31, 2016, $3.1 million of unrecognized compensation cost related to outstanding nonvested stock options was expected to be recognized by December 31, 2018.

A summary of option activity as of December 31, 2016, and changes during the year then ended, is presented below:

Non-qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2016	1,080,242	$ 60.33		
Granted	228,500	$ 54.09		
Exercised	(134,542)	$ 43.92		
Forfeited	—	$ —		
Expired	—	$ —		
Outstanding at December 31, 2016	1,174,200	$ 60.99	6.50 years	$ 10,060,848
Exercisable at December 31, 2016	668,400	$ 54.24	5.21 years	$ 7,461,562

EQM Awards

At the closing of EQM's IPO in July 2012, the Compensation Committee and the Board of Directors of EQM's general partner granted certain key Company employees performance awards under the EQM Total Return Program representing 146,490 common units of EQM. The performance condition related to the performance awards was satisfied on December 31, 2015 as the total unitholder return realized on EQM's common units from the date of grant was at least 10%.

The Company accounted for the EQM Total Return Program awards as equity awards using a $20.02 grant date fair value per unit as determined using a fair value model. The model projected the unit price for EQM common units at the ending point of the performance period. The price was generated using annual historical volatilities of peer group companies for the expected term of the awards, which was based upon the performance period. The range of expected volatilities calculated by the valuation model was 27% - 72%, and the weighted-average expected volatility was approximately 38%. Additional assumptions included the risk-free rate for the period within the contractual life of the awards based on the U.S. Treasury yield curve in effect at the time of grant and the expected EQM distribution growth rate of 10%. The confirmed awards vested and 153,367 awards including accrued distributions were distributed in EQM common units in February 2016.

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Effective in 2014, the Compensation Committee and the Board of Directors of EQM's general partner adopted the 2014 EQM Value Driver Award Program (2014 EQM VDPSU Program) under the 2009 LTIP and EQM's 2012 Long-Term Incentive Plan. The 2014 EQM VDPSU Program was established to align the interests of key employees with the interests of EQM unitholders and customers and the strategic objectives of EQM. Under the 2014 EQM VDPSU Program, 50% of the units confirmed vested upon payment following the first anniversary of the grant date; the remaining 50% of the units confirmed vested upon payment following the second anniversary of the grant date. The performance metrics were EQM's 2014 adjusted earnings before interest, income taxes, depreciation and amortization performance as compared to EQM's annual business plan and individual, business unit and value driver performance over the period of January 1, 2014 through December 31, 2014. The awards vested and 31,629 awards including accrued distributions were distributed in EQM common units in February 2015 and 28,998 awards including accrued distributions were distributed in EQM common units in February 2016. EQM accounted for these awards as equity awards using the $58.79 grant date fair value per unit which was equal to EQM's closing common unit price on the business day prior to the date of grant. Due to the graded vesting of the awards, EQM recognized compensation cost over the requisite service period for each separately vesting tranche of the award as though the award was, in substance, multiple awards. The total compensation cost capitalized related to the 2014 EQM VDPSU Program was less than $0.1 million and $0.3 million in 2015 and 2014, respectively.

Non-employee Directors' Share-Based Awards

The Company has historically granted to EQT non-employee directors share-based awards which vest upon grant of the awards. The share-based awards will be paid in cash or Company common stock following the directors' termination of service on the Company's Board of Directors. Awards that will be paid in cash are accounted for as liability awards and as such compensation expense is recorded based upon the fair value of the awards as remeasured at the end of each reporting period. Awards that will be settled in Company common stock are accounted for as equity awards and as such the Company recorded compensation expense for the fair value of the awards at the grant date fair value. A total of 191,541 non-employee director share-based awards including accrued dividends were outstanding as of December 31, 2016. A total of 37,620, 24,110 and 17,900 share-based awards were granted to non-employee directors during the years ended December 31, 2016, 2015 and 2014, respectively. The weighted average fair value of these grants, based on the Company's closing common stock price on the business day prior to the grant date, was $52.13, $75.52 and $89.78 for the years ended December 31, 2016, 2015 and 2014, respectively.

The general partner of EQM has granted EQM common unit-based phantom awards to its independent directors, which vested upon grant. The value of the phantom awards will be paid in EQM common units upon the director's termination of service on the general partner's Board of Directors. The Company accounts for these awards as equity awards and as such recorded compensation expense for the fair value of the awards at the grant date fair value. A total of 17,760 independent director unit-based awards including accrued distributions were outstanding as of December 31, 2016. A total of 2,610, 2,220 and 2,580 unit-based awards were granted to independent directors during the years ended December 31, 2016, 2015 and 2014, respectively. The weighted average fair value of these grants, based on EQM's closing common unit price on the business day prior to the grant date, was $75.46, $88.00 and $58.79 for the years ended December 31, 2016, 2015 and 2014, respectively.

The general partner of EQGP has granted EQGP common unit-based phantom awards to its independent directors, which vested upon grant. The value of the phantom awards will be paid in EQGP common units upon the director's termination of service on the general partner's Board of Directors. The Company accounts for these awards as equity awards and as such recorded compensation expense for the fair value of the awards at the grant date fair value. A total of 11,449 independent director unit-based awards including accrued distributions were outstanding as of December 31, 2016. A total of 8,270 and 2,910 unit-based awards were granted to independent directors during the years ended December 31, 2016 and 2015, respectively. The weighted average fair value of these grants, based on EQGP's closing common unit price on the business day prior to the grant date, was $21.57 and $28.77 for the years ended December 31, 2016 and 2015, respectively.

2017 Value Driver Performance Share Unit Award Program and 2017 Incentive Performance Share Unit Program

Effective in 2017, the Compensation Committee adopted the 2017 EQT Value Driver Performance Share Unit Award Program (2017 EQT VDPSU Program) and the 2017 Incentive Performance Share Unit Program (2017 Incentive PSU Program) under the 2014 LTIP. The 2017 EQT VDPSU Program and 2017 Incentive PSU Program were established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company.

A total of 319,610 units were granted under the 2017 EQT VDPSU Program. Fifty percent of the units confirmed under the 2017 EQT VDPSU will vest upon payment following the first anniversary of the grant date; the remaining 50% of the confirmed units under the 2017 EQT VDPSU Program will vest upon payment following the second anniversary of the grant date. The payout will vary between zero and 300% of the number of outstanding units contingent upon adjusted 2017 earnings before interest, income taxes, depreciation and amortization performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the period January 1, 2017 through December 31, 2017. If earned, the 2017 EQT VDPSU Program units are expected to be paid in cash.

A total of 197,960 units were granted under the 2017 Incentive PSU Program. The vesting of the units under the 2017 Incentive PSU Program will occur upon payment after December 31, 2019 (the end of the three-year performance period). The payout will vary between zero and 300% of the number of outstanding units contingent upon a combination of the level of total shareholder return relative to a predefined peer group and the level of production sales volume growth over the period January 1, 2017 through December 31, 2019. If earned, 67,290 of the 2017 Incentive PSU Program units are expected to be distributed in Company common stock and 130,670 of the 2017 Incentive PSU Program units are expected to be paid in cash.

2017 Stock Options

Effective January 1, 2017, the Compensation Committee granted 113,800 non-qualified stock options to key employees of the Company. The 2017 options are ten-year options, with an exercise price of $65.40, and are subject to three-year cliff vesting.

2017 Restricted Stock and Restricted Stock Unit Awards

Effective January 1, 2017, the Compensation Committee granted 33,650 restricted stock equity and 224,820 restricted stock unit liability awards. The restricted stock equity awards and restricted stock unit liability awards will be fully vested at the end of the three-year period commencing with the date of grant, assuming continued employment.

19. Concentrations of Credit Risk

Revenues and related accounts receivable from the EQT Production segment’s operations are generated primarily from the sale of produced natural gas, NGLs and crude oil to marketers, utility and industrial customers located mainly in the Appalachian Basin and northeastern United States and a gas processor in Kentucky and West Virginia. The Company’s current transportation portfolio also enables the Company to reach markets along the Gulf Coast and Midwestern portions of the United States. Additionally, a significant amount of revenues and related accounts receivable from EQT Gathering and EQT Transmission are generated from the transportation of natural gas in Pennsylvania and West Virginia. No single customer accounted for more than 10% of the Company's revenues for 2016. One customer within the EQT Production segment accounted for approximately 10% and 12% of the Company's total operating revenues in 2015 and 2014, respectively.

Approximately 68% and 79% of the Company’s accounts receivable balance as of December 31, 2016 and 2015, respectively, represented amounts due from marketers. The Company manages the credit risk of sales to marketers by limiting its dealings to those marketers that meet the Company’s criteria for credit and liquidity strength and by regularly monitoring these accounts. The Company may require letters of credit, guarantees, performance bonds or other credit enhancements from a marketer in order for that marketer to meet the Company’s credit criteria. As a result, the Company did not experience any significant defaults on sales of natural gas to marketers during the years ended December 31, 2016, 2015 or 2014.

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company’s OTC derivative instruments are primarily with financial institutions and, thus, are subject to events that would impact those companies individually as well as that industry as a whole.

The Company utilizes various processes and analyses to monitor and evaluate its credit risk exposures. These include monitoring current market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, the Company enters into transactions primarily with financial counterparties that are of investment grade, enters into netting agreements whenever possible and may obtain collateral or other security.

As of December 31, 2016, the Company was not in default under any derivative contracts and had no knowledge of default by any counterparty to its derivative contracts. During the year ended December 31, 2016, the Company made no adjustments to the fair value of derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in the Company's established fair value procedure. The Company monitors market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

20. Commitments and Contingencies

The Company has commitments for demand charges under existing long-term contracts and binding precedent agreements with various unconsolidated pipelines as well as commitments with third parties for processing capacity. Future payments for these items as of December 31, 2016 totaled $11.6 billion (2017 - $388.5 million, 2018 - $469.3 million, 2019 - $768.4 million, 2020 - $748.2 million, 2021 - $706.3 million and thereafter - $8.5 billion). The Company has entered into agreements to release some of its capacity to various third parties. The Company's commitments for demand charges under existing long-term contracts and binding precedent agreements with EQM totaled $6.0 billion as of December 31, 2016.

The Company has agreements with drilling contractors to provide drilling equipment and services to the Company. These obligations totaled approximately $60.9 million as of December 31, 2016. Operating lease rentals for drilling contractors, office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately $44.1 million in 2016, $85.2 million in 2015 and $65.6 million in 2014. Future lease payments under non-cancelable operating leases as of December 31, 2016 totaled $143.3 million (2017 - $55.5 million, 2018 - $24.5 million, 2019 - $12.2 million, 2020 – $9.8 million, 2021 - $9.8 million and thereafter - $31.5 million).

During 2015, the Company assigned its interest in the MVP Joint Venture to EQM. The MVP Joint Venture plans to construct the MVP, an estimated 300-mile natural gas interstate pipeline spanning from northern West Virginia to southern Virginia. The MVP Joint Venture has secured a total of 2.0 Bcf per day of 20-year firm capacity commitments, including a 1.29 Bcf per day firm capacity commitment by the Company.

If any credit rating agency downgrades the Company's or EQM's ratings, particularly below investment grade, the Company or EQM may be required to provide additional credit assurances in support of commercial agreements, such as pipeline capacity contracts, joint venture arrangements and subsidiary construction contracts, the amount of which may be substantial.

The Company is subject to various federal, state and local environmental and environmentally-related laws and regulations. These laws and regulations, which are constantly changing, can require expenditures for remediation and may in certain instances result in the assessment of fines. 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. The estimated costs associated with identified situations that require remedial action are accrued. However, certain costs are deferred as regulatory assets when recoverable through regulated rates. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material. Management believes that any such required expenditures will not be significantly different in either their nature or amount in the future and does not know of any environmental liabilities that will have a material effect on the Company’s financial position, results of operations or liquidity. The Company has identified situations that require remedial action for which approximately $13.0 million is included in other liabilities and credits in the Consolidated Balance Sheets as of December 31, 2016.

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 or 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.

21. Guarantees

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that once the energy-efficiency construction was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a period of years. The undiscounted maximum aggregate payments that may be due related to these guarantees were approximately $115 million as of December 31, 2016, extending at a decreasing amount for approximately 12 years.

As of December 31, 2016, EQM had issued a $91 million performance guarantee (the Initial Guarantee) in connection with the obligations of MVP Holdco to fund its proportionate share of the construction budget for the MVP. Upon the FERC's initial release to begin construction of the MVP, the Initial Guarantee will terminate, and EQM will be obligated to issue a new guarantee in an amount equal to 33% of MVP Holdco's remaining obligations to make capital contributions to the MVP Joint Venture in connection with the then remaining construction budget, less, subject to certain limits, any credit assurances issued by an affiliate of EQM under such affiliate's precedent agreement with the MVP Joint Venture.

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22. Interim Financial Information (Unaudited)

The following quarterly summary of operating results reflects variations due primarily to the volatility of natural gas commodity prices, including recognition of impairment expense on long-lived assets, and the seasonal nature of the Company's transmission, storage and marketing businesses.

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(Thousands, except per share amounts)			
2016 (a)				
Total operating revenues	$545,069	$127,531	$ 556,726	$ 379,022
Operating income (loss)	127,201	(324,492)	108,457	(189,466)
Net income (loss)	88,425	(180,807)	70,104	(108,785)
Net income (loss) attributable to EQT Corporation	5,636	(258,645)	(8,016)	(191,958)
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
Net income (loss)	$0.04	$(1.55)	$ (0.05)	$ (1.11)
Diluted:				
Net income (loss)	$0.04	$(1.55)	$ (0.05)	$ (1.11)
2015 (a)				
Total operating revenues (b)	$714,815	$439,589	$ 583,978	$ 601,380
Operating income	314,759	33,034	170,055	45,291
Net income (loss)	221,168	63,747	100,233	(63,262)
Net income (loss) attributable to EQT Corporation	173,427	5,536	40,787	(134,579)
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
Net income (loss)	$1.14	$0.04	$ 0.27	$ (0.88)
Diluted:				
Net income (loss)	$1.14	$0.04	$ 0.27	$ (0.88)

(a) The sum of the quarterly data in some cases may not equal the yearly total due to rounding.

(b) Differences between the amounts in the above table and those previously reported in the Company's 2015 Form 10-Qs are attributable to a reclassification of NGLs processing costs during 2015 which were previously reported as a reduction of operating revenues. The reclassification was immaterial to the amounts previously reported in the Company's 2015 Form 10-Qs.

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23. Natural Gas Producing Activities (Unaudited)

The supplementary information summarized below presents the results of natural gas and oil activities for the EQT Production segment in accordance with the successful efforts method of accounting for production activities.

Production Costs

The following tables present the total aggregate capitalized costs and the costs incurred relating to natural gas, NGLs and oil production activities (a):

	For the Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
At December 31:			
Capitalized Costs:			
Proved properties	$12,179,833	$10,918,499	$9,258,298
Unproved properties	1,698,826	898,270	824,527
Total capitalized costs	13,878,659	11,816,769	10,082,825
Accumulated depreciation and depletion	4,217,154	3,425,618	2,693,535
Net capitalized costs	$9,661,505	$8,391,151	$7,389,290

	For the Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Costs incurred: (a)			
Property acquisition:			
Proved properties (b)	$ 403,314	$ 23,890	$ 231,322
Unproved properties (c)	880,545	158,405	493,067
Exploration (d)	6,047	53,463	16,023
Development	777,787	1,633,498	1,697,501

(a) Amounts exclude capital expenditures for facilities and information technology.

(b) Amounts in 2016 include $256.2 million and $112.2 million for the purchase of Marcellus wells and leases, respectively, acquired in the 2016 transactions discussed in Note 9. Amounts include $198.2 million and $1.1 million for the purchase of Permian wells and leases, respectively, acquired in the Range Resources 2014 transaction.

(c) Amounts in 2016 include $770.4 million for the purchase of Marcellus leases acquired in the 2016 transactions discussed in Note 9. Amounts include $317.2 million for the purchase of Permian leases acquired in the Range Resources 2014 transaction.

(d) Amounts include capitalizable exploratory costs and exploration expense, excluding impairments.

Capitalized costs of unproved oil and gas properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes in development plans resulting from economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves prior to the expiration or abandonment of the lease, the related costs are expensed in the period in which that determination is made. For the years ended December 31, 2016, 2015 and 2014, the Company recorded unproved property impairments of $6.9 million, $19.7 million and $86.6 million, respectively, which are included in the impairment of long-lived assets in the Statements of Consolidated Operations. In addition, non-cash charges for leases which expired prior to drilling of $8.7 million, $37.4 million and $14.6 million are included in exploration expense for the years ended December 31, 2016, 2015 and 2014, respectively. Unproved properties had a net book value of $1,698.8 million and $898.3 million at December 31, 2016 and 2015, respectively.

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Results of Operations for Producing Activities

The following table presents the results of operations related to natural gas, NGLs and oil production:

	For the Years Ended December 31,		
	2016	2015	2014
	(Thousands)		
Revenues:			
Nonaffiliated	$1,594,997	$1,690,360	$2,107,635
Production costs	1,055,017	877,194	693,818
Exploration costs	13,410	61,970	21,665
Depreciation, depletion and accretion	859,018	765,298	630,115
Impairment of long-lived assets	6,939	122,469	267,339
Income tax (benefit) expense	(136,323)	(54,857)	195,405
Results of operations from producing activities (excluding corporate overhead)	$(203,064)	$(81,714)	$299,293

Reserve Information

The information presented below represents estimates of proved natural gas, NGLs and oil reserves 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 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; division of interest and production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems; the reserve reconciliation between prior year reserves and current year reserves is reviewed by senior management; and the estimates of proved natural gas, NGLs and oil reserves are 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.

Proved developed reserves represent only those reserves expected to be recovered from existing wells and support equipment. There were no differences between the internally prepared and externally audited estimates. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells after substantial development costs are incurred. 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 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. Reserves were assigned and projected by the Company's reserve engineers for locations within these proven areas and approved by Ryder Scott based on analogous type curves and offset production information. The audit utilized the performance method and the analogy method. Where historical reserve or production data was definitive, the performance method, which extrapolates historical data, was utilized. In other cases the analogy method, which calculates reserves based on correlations to comparable surrounding wells, was utilized. All of the Company's proved reserves are located in the United States.

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	Years Ended December 31,		
	2016	2015	2014
	(Millions of Cubic Feet)		
Total - Natural Gas, Oil, and NGLs (a)			
Proved developed and undeveloped reserves:			
Beginning of year	9,976,597	10,738,948	8,348,269
Revision of previous estimates	(472,285)	(2,194,675)	(301,351)
Purchase of hydrocarbons in place	2,395,776	—	102,713
Sale of hydrocarbons in place	—	(61)	(198,657)
Extensions, discoveries and other additions	2,384,682	2,051,071	3,276,054
Production	(776,363)	(618,686)	(488,080)
End of year	13,508,407	9,976,597	10,738,948
Proved developed reserves:			
Beginning of year	6,279,557	4,826,387	3,985,687
End of year	6,842,958	6,279,557	4,826,387
Proved undeveloped reserves:			
Beginning of year	3,697,040	5,912,561	4,362,582
End of year	6,665,449	3,697,040	5,912,561

(a) Oil and NGLs were converted at the rate of one thousand Bbl equal to approximately 6 million cubic feet (MMcf).

	Years Ended December 31,		
	2016	2015	2014
	(Millions of Cubic Feet)		
Natural Gas			
Proved developed and undeveloped reserves:			
Beginning of year	9,110,311	9,775,954	7,561,561
Revision of previous estimates	(607,171)	(2,059,531)	(228,085)
Purchase of natural gas in place	2,288,166	—	44,867
Sale of natural gas in place	—	(61)	(198,531)
Extensions, discoveries and other additions	2,241,528	1,955,935	3,040,938
Production	(700,967)	(561,986)	(444,796)
End of year	12,331,867	9,110,311	9,775,954
Proved developed reserves:			
Beginning of year	5,652,989	4,257,377	3,567,313
End of year	6,074,958	5,652,989	4,257,377
Proved undeveloped reserves:			
Beginning of year	3,457,322	5,518,577	3,994,248
End of year	6,256,909	3,457,322	5,518,577

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	Years Ended December 31,		
	2016	2015	2014
	(Thousands of Bbls)		
Oil (a)			
Proved developed and undeveloped reserves:			
Beginning of year	5,900	5,005	3,956
Revision of previous estimates	1,159	1,219	(905)
Purchase of oil in place	3	—	2,165
Sale of oil in place	—	—	(3)
Extensions, discoveries and other additions	62	419	241
Production	(729)	(743)	(449)
End of year	6,395	5,900	5,005
Proved developed reserves:			
Beginning of year	5,900	5,005	3,892
End of year	6,395	5,900	5,005
Proved undeveloped reserves:			
Beginning of year	—	—	64
End of year	—	—	—

(a) One thousand Bbl equals approximately 6 million cubic feet (MMcf).

	Years Ended December 31,		
	2016	2015	2014
	(Thousands of Bbls)		
NGLs (a)			
Proved developed and undeveloped reserves:			
Beginning of year	138,481	155,494	127,162
Revision of previous estimates	21,322	(23,743)	(11,306)
Purchase of NGLs in place	17,932	—	7,476
Sale of NGLs in place	—	—	(18)
Extensions, discoveries and other additions	23,797	15,437	38,945
Production	(11,837)	(8,707)	(6,765)
End of year	189,695	138,481	155,494
Proved developed reserves:			
Beginning of year	98,528	89,830	65,837
End of year	121,605	98,528	89,830
Proved undeveloped reserves:			
Beginning of year	39,953	65,664	61,325
End of year	68,090	39,953	65,664

(a) One thousand Bbl equals approximately 6 million cubic feet (MMcf).

2016 Changes in Reserves

- Transfer of 647 Bcfe of proved undeveloped reserves to proved developed reserves.
- Increase of 2,396 Bcfe associated with the acquisition of proved developed reserves (320 Bcfe) and proved undeveloped reserves (2,076 Bcfe) in the Company’s Marcellus and Upper Devonian plays.
- Extensions, discoveries and other additions of 2,385 Bcfe, which exceeded the 2016 production of 776 Bcfe.
- Negative revisions of 509 Bcfe from proved undeveloped locations, primarily due to 389 Bcfe from economic locations that the Company no longer expects to develop within 5 years of booking, along with the removal of locations that are no longer economic as determined in accordance with Securities and Exchange Commission (SEC) pricing requirements.

- Upward revisions of 68 Bcfe from proved developed locations, primarily due to increased reserves from producing wells.
- Negative revisions of 31 Bcfe associated with previously booked locations whose economic lives had been shortened due to reduced commodity prices.

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2015 Changes in Reserves

- Transfer of 1,528 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 2,051 Bcfe, which exceeded the 2015 production of 619 Bcfe.
- Negative revisions of 2,321 Bcfe from proved undeveloped locations, due primarily to the removal of locations that were no longer economic as determined in accordance with SEC pricing requirements and from 342 Bcfe from economic locations that the Company no longer expects to develop within 5 years of booking.
- Upward revisions of 386 Bcfe from proved developed locations, primarily due to increased reserves from producing wells.
- Negative revisions of 259 Bcfe associated with previously booked locations whose economic lives had been shortened due to reduced commodity prices.

2014 Changes in Reserves

- Transfer of 790 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 3,276 Bcfe, which exceeded the 2014 production of 488 Bcfe.
- Negative revisions of 1,200 Bcfe from proved undeveloped locations, primarily due to the removal of locations that the Company no longer expects to develop within 5 years of booking, including the remainder of proved undeveloped Huron locations that were no longer planned for development following the Company’s decision to suspend development of this play.
- Upward revisions of 711 Bcfe from proved undeveloped locations, primarily due to increased lengths on previously booked Marcellus locations.
- Upward revisions of 197 Bcfe from proved developed locations, primarily due to increased reserves from producing wells.
- Negative revisions of 9 Bcfe were associated with previously booked locations whose economic lives had been shortened due to reduced commodity prices.

During 2015, the Company revised its approach utilized to determine the gathering cost assumption within the Company's determination of reserves, which management believes to be a significant cost assumption included in the calculation of reserves. The Company believes the methodology that is currently utilized to determine the gathering rate reflects the Company’s current cash operating costs and gives consideration to EQT’s significant ownership interest in EQGP and EQM. Had the approach used in 2015 been used by the Company in 2014, the reserve estimates for 2014 would not have materially changed. Previously, the Company developed the gathering cost assumption based on the direct operating costs attributable to the operation of the wholly-owned midstream assets. Due to additional dropdowns of midstream assets from EQT to EQM in 2015 and the resulting increase in the proportion of the volumes that are gathered using EQM owned gathering assets, the current gathering rate assumption was developed in consideration of EQT’s significant ownership interest in its consolidated subsidiaries.

Standard Measure of Discounted Future Cash Flow

Management cautions that the standard measure of discounted future cash flows should not be viewed as an indication of the fair market value of natural gas and oil producing properties, nor of the future cash flows expected to be generated therefrom. The information presented does not give recognition to future changes in estimated reserves, selling prices or costs and has been discounted at a rate of 10%.

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Estimated future net cash flows from natural gas and oil reserves are as follows at December 31:

	2016	2015	2014
	(Thousands)		
Future cash inflows (a)	$24,011,281	$17,619,037	$42,352,358
Future production costs	(14,864,126)	(10,963,285)	(16,791,623)
Future development costs	(3,778,698)	(2,377,650)	(5,052,195)
Future income tax expenses	(1,753,067)	(1,333,989)	(7,718,406)
Future net cash flow	3,615,390	2,944,113	12,790,134
10% annual discount for estimated timing of cash flows	(2,626,636)	(1,966,559)	(7,980,106)
Standardized measure of discounted future net cash flows	$988,754	$977,554	$4,810,028

(a) The majority of the Company's production is sold through liquid trading points on interstate pipelines. For 2016, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2016 of $42.75 per Bbl of oil (first day of each month closing price for West Texas Intermediate (WTI)) less regional adjustments, $2.342 per Dth for Columbia Gas Transmission Corp., $1.348 per Dth for Dominion Transmission, Inc., $2.334 per Dth for the East Tennessee Natural Gas Pipeline, $1.325 per Dth for Texas Eastern Transmission Corp., $1.305 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company, $1.862 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company, $2.343 per Dth for Waha, and $2.402 per Dth for the Rockies Express Pipeline Zone 3. For 2016, NGL pricing using arithmetic averages of the closing prices on the first day of each month during 2016 for NGL components and adjusted using the regional component makeup of produced NGLs resulted in prices of $13.87 per Bbl of NGLs from certain West Virginia Marcellus reserves, $17.27 per Bbl of NGLs from certain Kentucky reserves, $14.71 per Bbl for Ohio Utica reserves, and $18.91 per Bbl for Permian reserves.

The majority of the Company's production is sold through liquid trading points on interstate pipelines. For 2015, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2015 of $50.28 per Bbl of oil (first day of each month closing price for WTI) less regional adjustments, $2.506 per Dth for Columbia Gas Transmission Corp., $1.394 per Dth for Dominion Transmission, Inc., $2.552 per Dth for the East Tennessee Natural Gas Pipeline, $1.428 per Dth for Texas Eastern Transmission Corp., $1.079 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company, $2.430 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company, $2.473 per Dth for Waha, and $2.549 per Dth for Houston Ship Channel. For 2015, NGLs pricing using arithmetic averages of the closing prices on the first day of each month during 2015 for NGLs components and adjusted using the regional component makeup of produced NGLs resulted in prices of $17.60 per Bbl of NGLs from certain West Virginia Marcellus reserves, $21.69 per Bbl of NGLs from certain Kentucky reserves, $16.84 per Bbl for Ohio Utica reserves, and $17.51 per Bbl for Permian reserves.

For 2014, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2014 of $94.99 per Bbl of oil (first day of each month closing price for WTI) less regional adjustments, $4.278 per Dth for Columbia Gas Transmission Corp., $3.191 per Dth for Dominion Transmission, Inc., $4.350 per Dth for the East Tennessee Natural Gas Pipeline, $3.258 per Dth for Texas Eastern Transmission Corp., $2.286 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company, $4.170 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company, $4.152 per Dth for Waha, and $4.243 per Dth for Houston Ship Channel. For 2014, NGLs pricing using arithmetic averages of the closing prices on the first day of each month during 2014 for NGLs components and adjusted using the regional component makeup of produced NGLs resulted in prices of $49.22 per Bbl of NGLs from certain West Virginia Marcellus reserves, $49.47 per Bbl of NGLs from certain Kentucky reserves, $47.11 per Bbl for Ohio Utica reserves, and $31.92 per Bbl for Permian reserves.

Holding production and development costs constant, a change in price of $0.20 per Dth for natural gas, $10 per barrel for oil and $10 per barrel for NGLs would result in a change in the December 31, 2016 discounted future net cash flows before income taxes of the Company's proved reserves of approximately $1.1 billion, $28.0 million and $715.1 million, respectively.

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Summary of changes in the standardized measure of discounted future net cash flows for the years ended December 31:

	2016	2015	2014
	(Thousands)		
Sales and transfers of natural gas and oil produced – net	$(539,980)	$(813,166)	$(1,413,817)
Net changes in prices, production and development costs	(1,129,026)	(5,546,405)	(1,548,352)
Extensions, discoveries and improved recovery, less related costs	590,885	264,735	2,300,923
Development costs incurred	402,891	971,186	1,023,075
Purchase of minerals in place – net	592,078	—	72,139
Sale of minerals in place – net	—	(43)	(146,476)
Revisions of previous quantity estimates	(60,959)	(1,541,418)	(222,196)
Accretion of discount	122,674	600,099	578,676
Net change in income taxes	(91,823)	2,424,200	(529,337)
Timing and other	124,460	(191,662)	744,114
Net increase (decrease)	11,200	(3,832,474)	858,749
Beginning of year	977,554	4,810,028	3,951,279
End of year	$988,754	$977,554	$4,810,028

24. Subsequent Events

On February 1, 2017, the Company acquired approximately 14,000 net Marcellus acres located in Marion, Monongalia and Wetzel Counties, West Virginia, for $130 million.

On February 8, 2017, the Company won a bankruptcy auction to acquire approximately 53,400 core Marcellus acres primarily located in Wetzel, Marshall, Tyler and Marion Counties of West Virginia, for $527 million, subject to final Bankruptcy Court approval on February 10, 2017. The assets also include 174 operated Marcellus wells currently producing approximately 80 MMcfe per day, 20 miles of gathering pipeline and 32,000 acres outside the Company’s core development area.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not Applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including the Company's Principal Executive Officer and Principal Financial Officer, an evaluation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), was conducted as of the end of the period covered by this report. Based on that evaluation, the Principal Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of the end of the period covered by this report.

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2016 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

The management of EQT is responsible for establishing and maintaining adequate internal control over financial reporting. EQT's internal control system is designed to provide reasonable assurance to the Company's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. All internal control systems, no matter how well designed, have inherent limitations. Accordingly, even effective controls can provide only reasonable assurance with respect to financial statement preparation and presentation.

EQT's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (2013). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2016.

Ernst & Young LLP (Ernst & Young), the independent registered public accounting firm that audited the Company's Consolidated Financial Statements, has issued an attestation report on the Company's internal control over financial reporting. Ernst & Young's attestation report on the Company's internal control over financial reporting appears in Part II, Item 8 of this Annual Report on Form 10-K and is incorporated by reference herein.

Item 9B. Other Information

Not Applicable.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following information is incorporated herein by reference from the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 19, 2017, which proxy statement will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2016:

- Information required by Item 401 of Regulation S-K with respect to directors is incorporated herein by reference from the sections captioned "Item No. 1 – Election of Directors," and "Corporate Governance and Board Matters" in the Company's definitive proxy statement;

- Information required by Item 405 of Regulation S-K with respect to compliance with Section 16(a) of the Exchange Act is incorporated herein by reference from the section captioned "Equity Ownership – Section 16(a) Beneficial Ownership Reporting Compliance" in the Company's definitive proxy statement;

- Information required by Item 407(d)(4) of Regulation S-K with respect to disclosure of the existence of the Company's separately-designated standing Audit Committee and the identification of the members of the Audit Committee is incorporated herein by reference from the section captioned "Corporate Governance and Board Matters – Board Meetings and Committees – Audit Committee" in the Company's definitive proxy statement; and

- Information required by Item 407(d)(5) of Regulation S-K with respect to disclosure of the Company's audit committee financial expert is incorporated herein by reference from the section captioned "Corporate Governance and Board Matters – Board Meetings and Committees – Audit Committee" in the Company's definitive proxy statement.

Information required by Item 401 of Regulation S-K with respect to executive officers is included after Item 4 at the end of Part I of this Annual Report on Form 10-K under the caption "Executive Officers of the Registrant (as of February 9, 2017)," and is incorporated herein by reference.

The Company has adopted a code of business conduct and ethics applicable to all directors and employees, including the principal executive officer, principal financial officer and principal accounting officer. The code of business conduct and ethics is posted on the Company's website, http://www.eqt.com (accessible by clicking on the "Investors" link on the main page followed by the "Corporate Governance" link and the "Charters and Documents" link), and a printed copy will be delivered free of charge on request by writing to the corporate secretary at EQT Corporation, c/o Corporate Secretary, 625 Liberty Avenue, Suite 1700, Pittsburgh, Pennsylvania 15222. The Company intends to satisfy the disclosure requirement regarding certain amendments to, or waivers from, provisions of its code of business conduct and ethics by posting such information on the Company's website.

Item 11. Executive Compensation

The following information is incorporated herein by reference from the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 19, 2017, which proxy statement will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2016:

- Information required by Item 402 of Regulation S-K with respect to named executive officer and director compensation is incorporated herein by reference from the sections captioned "Executive Compensation - Compensation Discussion and Analysis," "Executive Compensation - Compensation Tables," "Executive Compensation - Compensation Policies and Practices and Risk Management," and "Directors' Compensation" in the Company's definitive proxy statement; and

Information required by paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K with respect to certain matters related to the Management Development and Compensation Committee of the Company's Board of Directors is incorporated herein by reference from the sections captioned “Corporate Governance and Board Matters - Compensation Committee Interlocks and Insider Participation” and “Executive Compensation - Report of the Management Development and Compensation Committee” in the Company’s definitive proxy statement.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by Item 403 of Regulation S-K with respect to stock ownership of significant shareholders, directors and executive officers is incorporated herein by reference to the sections captioned "Equity Ownership - Stock Ownership of Significant Shareholders" and "Equity Ownership - Equity Ownership of Directors and Executive Officers" in the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 19, 2017, which will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2016.

Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2016 with respect to shares of the Company's common stock that may be issued under the Company's existing equity compensation plans, including the 2014 Long-Term Incentive Plan (2014 LTIP), the 2009 Long-Term Incentive Plan (2009 LTIP), the 1999 Non-Employee Directors' Stock Incentive Plan (1999 NEDSIP), the 2005 Directors' Deferred Compensation Plan (2005 DDCP), the 1999 Directors' Deferred Compensation Plan (1999 DDCP) and the 2008 Employee Stock Purchase Plan (2008 ESPP):

Plan Category	Number Of Securities To Be Issued Upon Exercise Of Outstanding Options, Warrants and Rights (A)		Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (B)		Number Of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected In Column A) (C)	
Equity Compensation Plans Approved by Shareholders [1]	4,667,735	[2]	$ 60.99	[3]	3,293,943	[4]
Equity Compensation Plans Not Approved by Shareholders [5]	24,567	[6]	N/A		169,466	
Total	4,692,302		$ 60.99		3,463,409	

(1) Consists of the 2014 LTIP, the 2009 LTIP, the 1999 NEDSIP and the 2008 ESPP. Effective as of April 30, 2014, in connection with the adoption of the 2014 LTIP, the Company ceased making new grants under the 2009 LTIP. Effective as of April 22, 2009, in connection with the adoption of the 2009 LTIP, the Company ceased making new grants under the 1999 NEDSIP. The 2009 LTIP and the 1999 NEDSIP remain effective solely for the purpose of issuing shares upon the exercise or payout of awards outstanding under such plans on April 30, 2014 (for the 2009 LTIP) and April 22, 2009 (for the 1999 NEDSIP).

(2) Consists of (i) 386,700 shares subject to outstanding stock options under the 2014 LTIP; (ii) 2,475,457 shares subject to outstanding performance awards under the 2014 LTIP, inclusive of dividend reinvestments thereon (counted at a 3X multiple assuming maximum performance is achieved under the awards (representing 825,152 target awards and dividend reinvestments thereon)); (iii) 208,866 performance awards under the 2014 LTIP, inclusive of dividend reinvestments thereon (based upon award amounts previously confirmed by the Management Development and Compensation Committee but subject to continuing service conditions, and therefore not subject to any additional multiplier); (iv) 50,291 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon; (v) 787,500 shares subject to outstanding stock options

under the 2009 LTIP; (vi) 718,133 shares subject to outstanding performance awards under the 2009 LTIP, inclusive of dividend reinvestments thereon (counted at a 3X multiple assuming maximum performance is achieved under the awards (representing 239,378 target awards and dividend reinvestments thereon)); (vii) 34,913 shares subject to outstanding directors' deferred stock units under the 2009 LTIP, inclusive of dividend reinvestments thereon; and (viii) 5,875 shares subject to outstanding directors' deferred stock units under the 1999 NEDSIP, inclusive of dividend reinvestments thereon.

(3) The weighted-average exercise price is calculated based solely upon outstanding stock options under the 2014 LTIP and the 2009 LTIP and excludes deferred stock units under the 2014 LTIP, the 2009 LTIP and the 1999 NEDSIP and performance awards under the 2014 LTIP and the 2009 LTIP. The weighted average remaining term of the stock options was 6.50 years as of December 31, 2016.

(4) Consists of (i) 3,242,429 shares available for future issuance under the 2014 LTIP, (ii) a "notional" deficit of (564,980) shares under the 2009 LTIP and (iii) 616,494 shares available for future issuance under the 2008 ESPP. As of December 31, 2016, 3,884 shares were subject to purchase under the 2008 ESPP.

The "notional" deficit under the 2009 LTIP results from counting outstanding performance awards under the 2009 LTIP at a 3X multiple assuming maximum performance is achieved under the awards. The actual number of shares the Management Development and Compensation Committee will award at the end of the applicable performance periods will range between 0% and 300% of the target awards, based upon, among other things, the Company's achievement of stated performance measures under the awards, as certified by the Management Development and Compensation Committee. However, to the extent insufficient

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shares remain available for future issuance under the 2009 LTIP upon the applicable payout dates of such performance awards, the awards will be settled (i) with shares reserved for issuance under the 2014 LTIP or (ii) in cash.

(5) Consists of the 2005 DDCP and the 1999 DDCP, each of which is described below.

(6) Reflects the number of shares invested in the EQT Common Stock Fund, payable in shares of common stock, allocated to non-employee directors' accounts under the 2005 DDCP and the 1999 DDCP as of December 31, 2016.

2005 Directors' Deferred Compensation Plan

The 2005 DDCP was adopted by the Management Development and Compensation Committee, effective January 1, 2005. Neither the original adoption of the plan nor its amendments required approval by the Company's shareholders. The plan allows non-employee directors to defer all or a portion of their directors' fees and retainers. Amounts deferred are payable on or following retirement from the Board unless an early payment is authorized after the director suffers an unforeseeable financial emergency. In addition to deferred directors' fees and retainers, the deferred stock units granted to directors on or after January 1, 2005 under the 1999 NEDSIP, the 2009 LTIP and the 2014 LTIP are administered under this plan.

1999 Directors' Deferred Compensation Plan

The 1999 DDCP was suspended as of December 31, 2004. The plan continues to operate for the sole purpose of administering vested amounts deferred under the plan on or prior to December 31, 2004. Deferred amounts are generally payable on or following retirement from the Board, but may be payable earlier if an early payment is authorized after a director suffers an unforeseeable financial emergency. In addition to deferred directors' fees and retainers and a one-time grant of deferred shares in 1999 resulting from the curtailment of the directors' retirement plan, the deferred stock units granted to directors and vested prior to January 1, 2005 under the 1999 NEDSIP are administered under this plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by Items 404 and 407(a) of Regulation S-K with respect to director independence and related person transactions is incorporated herein by reference to the section captioned "Corporate Governance and Board Matters – Independence and Related Person Transactions" in the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 19, 2017, which proxy statement will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2016.

Item 14. Principal Accounting Fees and Services

Information required by Item 9(e) of Schedule 14A is incorporated herein by reference to the section captioned "Item No. 4 – Ratification of Appointment of Independent Registered Public Accounting Firm" in the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 19, 2017, which proxy statement will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2016.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1 Financial Statements

The financial statements listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

2 Financial Statement Schedule

Schedule II - Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 2016

All other schedules are omitted since the subject matter thereof is either not present or is not present in amounts sufficient to require submission of the schedules.

3 Exhibits

The exhibits listed on the accompanying index to exhibits (pages 126 through 133) are filed (or, as applicable, furnished) as part of this Annual Report on Form 10-K.

EQT CORPORATION

INDEX TO FINANCIAL STATEMENTS COVERED
BY REPORT OF INDEPENDENT REGISTERED
PUBLIC ACCOUNTING FIRM

1. The following Consolidated Financial Statements of EQT Corporation and Subsidiaries are included in Item 8:

2. Schedule for the Three Years Ended December 31, 2016 included in Part IV:

All other schedules are omitted since the subject matter thereof is either not present or is not present in amounts sufficient to require submission of the schedules.

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EQT CORPORATION AND SUBSIDIARIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2016

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Period	(Deductions) Additions Charged to Costs and Expenses	Additions Charged to Other Accounts	Deductions	Balance at End of Period
	(Thousands)				
Valuation allowance for deferred tax assets:					
2016	$156,084	$24,706	$21,536	$(904)	$201,422
2015	$64,987	$91,097	$—	$—	$156,084
2014	$56,404	$9,314	$—	$(731)	$64,987

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
2.01(a)	Master Purchase Agreement dated as of December 19, 2012 among the Company, Distribution Holdco, LLC and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.1 to Form 8-K filed on December 20, 2012
2.01(b)	Amendment No. 1 to Master Purchase Agreement dated as of February 22, 2013 among the Company, Distribution Holdco, LLC and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.01 to Form 10-Q for the quarter ended March 31, 2013
2.01(c)	Amendment No. 2 to Master Purchase Agreement dated as of December 17, 2013 among the Company, Distribution Holdco, LLC and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.1 to Form 8-K filed on December 19, 2013
2.02(a)	Asset Exchange Agreement dated as of December 19, 2012 between the Company and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.2 to Form 8-K filed on December 20, 2012
2.02(b)	Amendment to Asset Exchange Agreement dated as of December 17, 2013 between the Company and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.2 to Form 8-K filed on December 19, 2013
3.01	Restated Articles of Incorporation of EQT Corporation (amended through April 17, 2013)	Incorporated herein by reference to Exhibit 3.01 to Form 10-Q for the quarter ended March 31, 2013
3.02	Amended and Restated Bylaws of EQT Corporation (amended through October 14, 2015)	Incorporated herein by reference to Exhibit 3.1 to Form 8-K filed on October 15, 2015
4.01(a)	Indenture dated as of April 1, 1983 between the Company and Pittsburgh National Bank, as Trustee	Incorporated herein by reference to Exhibit 4.01(a) to Form 10-K for the year ended December 31, 2007
4.01(b)	Instrument appointing Bankers Trust Company as successor trustee to Pittsburgh National Bank	Incorporated herein by reference to Exhibit 4.01(b) to Form 10-K for the year ended December 31, 1998
4.01(c)	1991 Supplemental Indenture dated as of March 15, 1991 between the Company and Bankers Trust Company, as Trustee, eliminating limitations on liens and additional funded debt	Incorporated herein by reference to Exhibit 4.01(f) to Form 10-K for the year ended December 31, 1996
4.01(d)	Resolution adopted August 19, 1991 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 27, establishing the terms and provisions of the Series A Medium-Term Notes	Incorporated herein by reference to Exhibit 4.01(g) to Form 10-K for the year ended December 31, 1996
4.01(e)		

	Resolutions adopted July 6, 1992 and February 19, 1993 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 8, establishing the terms and provisions of the Series B Medium-Term Notes	Incorporated herein by reference to Exhibit 4.01(h) to Form 10-K for the year ended December 31, 1997
4.01(f)	Resolution adopted July 14, 1994 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 and 2, establishing the terms and provisions of the Series C Medium-Term Notes	Incorporated herein by reference to Exhibit 4.01(i) to Form 10-K for the year ended December 31, 1995
4.01(g)	Second Supplemental Indenture dated as of June 30, 2008 between the Company and Deutsche Bank Trust Company Americas, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Incorporated herein by reference to Exhibit 4.01(g) to Form 8-K filed on July 1, 2008

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
4.02(a)	Indenture dated as of July 1, 1996 between the Company and The Bank of New York, as successor to Bank of Montreal Trust Company, as Trustee	Incorporated herein by reference to Exhibit 4.01(a) to Form S-4 Registration Statement (#333-103178) filed on February 13, 2003
4.02(b)	Resolutions adopted January 18 and July 18, 1996 by the Board of Directors of the Company and Resolution adopted July 18, 1996 by the Executive Committee of the Board of Directors of the Company, establishing the terms and provisions of the 7.75% Debentures issued July 29, 1996	Incorporated herein by reference to Exhibit 4.01(j) to Form 10-K for the year ended December 31, 1996
4.02(c)	Officer's Declaration dated as of February 20, 2003 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of up to $200,000,000	Incorporated herein by reference to Exhibit 4.01(c) to Form S-4 Registration Statement (#333-104392) filed on April 8, 2003
4.02(d)	Supplemental Indenture dated as of June 30, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Incorporated herein by reference to Exhibit 4.02(f) to Form 8-K filed on July 1, 2008
4.03(a)	Indenture dated as of March 18, 2008 between the Company and The Bank of New York, as Trustee	Incorporated herein by reference to Exhibit 4.1 to Form 8-K filed on March 18, 2008
4.03(b)	First Supplemental Indenture (including the form of senior note) dated as of March 18, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which the 6.5% Senior Notes due 2018 were issued	Incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on March 18, 2008
4.03(c)	Second Supplemental Indenture dated as of June 30, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Incorporated herein by reference to Exhibit 4.03(c) to Form 8-K filed on July 1, 2008
4.03(d)	Third Supplemental Indenture dated as of May 15, 2009 between the Company and The Bank of New York, as Trustee, pursuant to which the 8.13% Senior Notes due 2019 were issued	Incorporated herein by reference to Exhibit 4.1 to Form 8-K filed on May 15, 2009
4.03(e)	Fourth Supplemental Indenture dated as of November 7, 2011 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 4.88% Senior Notes due 2021 were issued	Incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on November 7, 2011
4.04(a)		

Indenture dated as of August 1, 2014 among EQT Midstream Partners, LP, the subsidiaries of EQT Midstream Partners, LP party thereto, and The Bank of New York Mellon Trust Company, N.A., as Trustee	Incorporated herein by reference to Exhibit 4.01 to Form 10-Q for the quarter ended September 30, 2014

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
4.04(b)	First Supplemental Indenture dated as of August 1, 2014 among EQT Midstream Partners, LP, the subsidiaries of EQT Midstream Partners, LP party thereto, and The Bank of New York Mellon Trust Company, N.A., as Trustee, pursuant to which the EQT Midstream Partners, LP 4.00% Senior Notes due 2024 were issued	Incorporated herein by reference to Exhibit 4.02 to Form 10-Q for the quarter ended September 30, 2014
4.04(c)	Second Supplemental Indenture dated as of November 4, 2016 between EQT Midstream Partners, LP and The Bank of New York Mellon Trust Company, N.A., as Trustee, pursuant to which the EQT Midstream Partners, LP 4.125% Senior Notes due 2026 were issued	Incorporated herein by reference to Exhibit 4.2 to EQT Midstream Partners, LP's Form 8-K (#001-35574) filed on November 4, 2016
* 10.01(a)	2009 Long-Term Incentive Plan (as amended and restated July 11, 2012)	Incorporated herein by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2012
* 10.01(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (pre-2013 grants)	Incorporated herein by reference to Exhibit 10.02(b) to Form 10-K for the year ended December 31, 2012
* 10.01(c)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (pre-2012 grants)	Incorporated herein by reference to Exhibit 10.01(q) to Form 10-K for the year ended December 31, 2010
* 10.01(d)	Form of Amendment to Stock Option Award Agreements	Incorporated herein by reference to Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2011
* 10.01(e)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2012 grants)	Incorporated herein by reference to Exhibit 10.02(n) to Form 10-K for the year ended December 31, 2011
* 10.01(f)	2012 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(q) to Form 10-K for the year ended December 31, 2011
* 10.01(g)	Form of Participant Award Agreement under 2012 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(r) to Form 10-K for the year ended December 31, 2011
* 10.01(h)	Form of EQM TSR Performance Award Agreement under 2009 Long-Term Incentive Plan and EQT Midstream Services, LLC 2012 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.02(r) to Form 10-K for the year ended December 31, 2012

* 10.01(i)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (2013 and 2014 grants)	Incorporated herein by reference to Exhibit 10.02(s) to Form 10-K for the year ended December 31, 2012
* 10.01(j)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2013 grants)	Incorporated herein by reference to Exhibit 10.02(t) to Form 10-K for the year ended December 31, 2012
* 10.01(k)	2013 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(u) to Form 10-K for the year ended December 31, 2012
* 10.01(l)	Form of Participant Award Agreement under 2013 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(v) to Form 10-K for the year ended December 31, 2012

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.01(m)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2014 grants)	Incorporated herein by reference to Exhibit 10.02(v) to Form 10-K for the year ended December 31, 2013
* 10.01(n)	2014 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(w) to Form 10-K for the year ended December 31, 2013
* 10.01(o)	Form of Participant Award Agreement under 2014 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(x) to Form 10-K for the year ended December 31, 2013
* 10.02(a)	2014 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on May 1, 2014
* 10.02(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2014 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.03(b) to Form 10-K for the year ended December 31, 2014
* 10.02(c)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (pre-2017 grants)	Incorporated herein by reference to Exhibit 10.03(c) to Form 10-K for the year ended December 31, 2014
* 10.02(d)	Form of Restricted Stock Award Agreement under 2014 Long-Term Incentive Plan	Filed herewith as Exhibit 10.02(d)
* 10.02(e)	2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(d) to Form 10-K for the year ended December 31, 2014
* 10.02(f)	Form of Participant Award Agreement under 2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(e) to Form 10-K for the year ended December 31, 2014
* 10.02(g)	Amendment to 2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(f) to Form 10-K for the year ended December 31, 2014
* 10.02(h)	2016 Incentive Performance Share Unit Program	Incorporated herein by reference to Exhibit 10.02(g) to Form 10-K for the year ended December 31, 2015
* 10.02(i)	Form of Participant Award Agreement under 2016 Incentive Performance Share Unit Program	Incorporated herein by reference to Exhibit 10.02(h) to Form 10-K for the year ended

		December 31, 2015
* 10.02(j)	2016 Restricted Stock Award Agreement (Standard) for Robert J. McNally	Incorporated herein by reference to Exhibit 10.03 to Form 10-Q for the quarter ended March 31, 2016
* 10.02(k)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (2017 grants)	Filed herewith as Exhibit 10.02(k)
* 10.02(l)	2017 Incentive Performance Share Unit Program	Filed herewith as Exhibit 10.02(l)
* 10.02(m)	Form of Participant Award Agreement under 2017 Incentive Performance Share Unit Program	Filed herewith as Exhibit 10.02(m)

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.03(a)	EQT GP Services, LLC 2015 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.3 to EQT GP Holdings, LP's Form 8-K (#001-37380) filed on May 15, 2015
* 10.03(b)	Form of EQT GP Holdings, LP Phantom Unit Award Agreement	Incorporated herein by reference to Exhibit 10.5 to Amendment No. 1 to EQT GP Holdings, LP's Form S-1 Registration Statement (#333-202053) filed on April 1, 2015
* 10.04	EQT Midstream Services, LLC 2012 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.03 to Form 10-K for the year ended December 31, 2012
* 10.05(a)	1999 Non-Employee Directors’ Stock Incentive Plan (as amended and restated December 3, 2008)	Incorporated herein by reference to Exhibit 10.02(a) to Form 10-K for the year ended December 31, 2008
* 10.05(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 1999 Non-Employee Directors’ Stock Incentive Plan	Incorporated herein by reference to Exhibit 10.04(c) to Form 10-K for the year ended December 31, 2006
* 10.06	2011 Executive Short-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.2 to Form 8-K filed on May 10, 2011
* 10.07	2016 Executive Short-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on April 21, 2016
* 10.08	2006 Payroll Deduction and Contribution Program (as amended and restated July 7, 2015)	Incorporated herein by reference to Exhibit 10.06 to Form 10-Q for the quarter ended June 30, 2015
* 10.09	1999 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014)	Incorporated herein by reference to Exhibit 10.08 to Form 10-K for the year ended December 31, 2014
* 10.10	2005 Directors’ Deferred Compensation Plan (as amended and restated December 3, 2014)	Incorporated herein by reference to Exhibit 10.09 to Form 10-K for the year ended December 31, 2014
* 10.11(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and David L. Porges	Incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on July 31, 2015
* 10.11(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and David L. Porges	Incorporated herein by reference to Exhibit 10.10(b) to Form 10-K for the year ended December 31, 2012
* 10.11(c)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015	Incorporated herein by reference to Exhibit 10.6 to Form 8-K filed on July 31, 2015

between the Company and David L. Porges

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.12(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and Steven T. Schlotterbeck	Incorporated herein by reference to Exhibit 10.5 to Form 8-K filed on July 31, 2015
* 10.12(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Steven T. Schlotterbeck	Incorporated herein by reference to Exhibit 10.14(b) to Form 10-K for the year ended December 31, 2012
* 10.12(c)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and Steven T. Schlotterbeck	Incorporated herein by reference to Exhibit 10.10 to Form 8-K filed on July 31, 2015
* 10.13(a)	Offer letter dated as of March 7, 2016 between the Company and Robert J. McNally	Incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on March 17, 2016
* 10.13(b)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of March 10, 2016 between the Company and Robert J. McNally	Incorporated herein by reference to Exhibit 10.02 to Form 10-Q for the quarter ended March 31, 2016
* 10.14(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.3 to Form 8-K filed on July 31, 2015
* 10.14(b)	Amendment to Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement effective as of January 1, 2016 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.12(b) to Form 10-K for the year ended December 31, 2015
* 10.14(c)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.12(b) to Form 10-K for the year ended December 31, 2012
* 10.14(d)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.8 to Form 8-K filed on July 31, 2015
* 10.14(e)		

	Transition Agreement and General Release dated as of January 9, 2017 between the Company and Randall L. Crawford	Filed herewith as Exhibit 10.14(e)
* 10.15(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and Lewis B. Gardner	Incorporated herein by reference to Exhibit 10.4 to Form 8-K filed on July 31, 2015
* 10.15(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Lewis B. Gardner	Incorporated herein by reference to Exhibit 10.13(b) to Form 10-K for the year ended December 31, 2012
* 10.15(c)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and Lewis B. Gardner	Incorporated herein by reference to Exhibit 10.9 to Form 8-K filed on July 31, 2015
* 10.16(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.2 to Form 8-K filed on July 31, 2015
* 10.16(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.11(b) to Form 10-K for the year ended December 31, 2012
* 10.16(c)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.7 to Form 8-K filed on July 31, 2015

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.16(d)	Employment Agreement dated as of March 17, 2016 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.04 to Form 10-Q for the quarter ended March 31, 2016
* 10.16(e)	Revised Executive Alternative Work Arrangement Employment Agreement effective as of January 3, 2017 between the Company and Philip P. Conti	Filed herewith as Exhibit 10.16(e)
* 10.17(a)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and David L. Porges	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended June 30, 2015
* 10.17(b)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and Steven T. Schlotterbeck	Incorporated herein by reference to Exhibit 10.05 to Form 10-Q for the quarter ended June 30, 2015
* 10.17(c)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.03 to Form 10-Q for the quarter ended June 30, 2015
* 10.17(d)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and Lewis B. Gardner	Incorporated herein by reference to Exhibit 10.04 to Form 10-Q for the quarter ended June 30, 2015
* 10.17(e)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.02 to Form 10-Q for the quarter ended June 30, 2015
* 10.18	Form of Indemnification Agreement between the Company and each executive officer and each outside director	Incorporated herein by reference to Exhibit 10.18 to Form 10-K for the year ended December 31, 2008

10.19	Amended and Restated Revolving Credit Agreement dated as of February 18, 2014 among the Company, PNC Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, Wells Fargo Bank, National Association, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Bank of America, N.A., Barclays Bank PLC, Citibank, N.A., JPMorgan Chase Bank, N.A. and SunTrust Bank, as Syndication Agents, and the other lender parties thereto	Incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on February 18, 2014
10.20	First Amended and Restated Limited Liability Company Agreement of Mountain Valley Pipeline, LLC dated as of August 28, 2014 among MVP Holdco, LLC, US Marcellus Gas Infrastructure, LLC, and Mountain Valley Pipeline, LLC. Specific items in this exhibit have been redacted, as marked by three asterisks (***) because confidential treatment for those terms was granted by the SEC. The redacted material has been separately filed with the SEC.	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q/A filed on December 3, 2014
10.21	Assignment and Assumption Agreement dated as of March 30, 2015 among EQT Gathering, LLC, EQT Midstream Partners, LP and MVP Holdco, LLC	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended March 31, 2015

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
21	Schedule of Subsidiaries	Filed herewith as Exhibit 21
23.01	Consent of Independent Registered Public Accounting Firm	Filed herewith as Exhibit 23.01
23.02	Consent of Ryder Scott Company, L.P.	Filed herewith as Exhibit 23.02
31.01	Rule 13(a)-14(a) Certification of Principal Executive Officer	Filed herewith as Exhibit 31.01
31.02	Rule 13(a)-14(a) Certification of Principal Financial Officer	Filed herewith as Exhibit 31.02
32	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	Furnished herewith as Exhibit 32
99	Independent Petroleum Engineers' Audit Report	Filed herewith as Exhibit 99
101	Interactive Data File	Filed herewith as Exhibit 101

The Company agrees to furnish to the SEC, upon request, copies of instruments with respect to long-term debt which have not previously been filed.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EQT CORPORATION

By: /s/ DAVID L. PORGES
David L. Porges
Chief Executive Officer
February 9, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ DAVID L. PORGES David L. Porges (Principal Executive Officer)	Chairman and Chief Executive Officer	February 9, 2017
/s/ ROBERT J. MCNALLY Robert J. McNally (Principal Financial Officer)	Senior Vice President and Chief Financial Officer	February 9, 2017
/s/ JIMMI SUE SMITH Jimmi Sue Smith (Principal Accounting Officer)	Chief Accounting Officer	February 9, 2017
/s/ VICKY A. BAILEY Vicky A. Bailey	Director	February 9, 2017
/s/ PHILIP G. BEHRMAN Philip G. Behrman	Director	February 9, 2017
/s/ KENNETH M. BURKE Kenneth M. Burke	Director	February 9, 2017
/s/ A. BRAY CARY JR. A. Bray Cary, Jr.	Director	February 9, 2017
/s/ MARGARET K. DORMAN Margaret K. Dorman	Director	February 9, 2017
/s/ JAMES E. ROHR James E. Rohr	Director	February 9, 2017
/s/ STEVEN T. SCHLOTTERBECK Steven T. Schlotterbeck	Director	February 9, 2017
/s/ STEPHEN A. THORINGTON Stephen A. Thorington	Director	February 9, 2017

/s/ LEE T. TODD, JR. Lee T. Todd, Jr.	Director	February 9, 2017
/s/ CHRISTINE J. TORETTI Christine J. Toretti	Director	February 9, 2017