EQT Corp
Form 10-K
February 15, 2018
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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, 2017

[ ]	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 001-03551

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, Suite 1700	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. [X]

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

Large accelerated filer X	Accelerated filer ___
Non-accelerated filer ___ (Do not check if a smaller reporting company)	Smaller reporting company ___
	Emerging growth company ___

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

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

The aggregate market value of voting stock held by non-affiliates of the registrant as of June 30, 2017: $10.1 billion

The number of shares (in thousands) of common stock outstanding as of January 31, 2018: 264,473

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the 2018 annual meeting of shareholders will be filed with the Securities and Exchange Commission within 120 days after the close of the Company's fiscal year ended December 31, 2017 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.

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).

option – a contract that gives the buyer the right, but not the obligation, to buy or sell a specified quantity of a commodity or other instrument at a specific price within a specified period of time.

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
MMgal = million gallons
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 and Goodwill” 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, average lateral lengths 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; the Company's ability to maximize recoveries per acre; 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 cost, capacity, timing of regulatory approvals and anticipated in-service date of the Mountain Valley Pipeline (MVP) project; the ultimate terms, partners and structure of Mountain Valley Pipeline, LLC; technology (including drilling and completion techniques); monetization transactions, including asset sales, joint ventures or other transactions involving the Company’s assets; acquisition transactions; whether the Company will sell its Ohio midstream assets to EQT Midstream Partners, LP and the timing of such transaction or transactions; the Company’s ability to achieve the anticipated synergies, operational efficiencies and returns from its acquisition of Rice Energy Inc.; the timing of the Company's announcement of a decision for addressing its sum-of-the-parts discount; 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 and capital contributions; 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; the effects of government regulation and litigation; the expected impact of the Tax Cuts and Jobs Act of 2017; 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 five business segments: EQT Production, EQM Gathering, EQM Transmission, RMP Gathering and RMP Water. EQT Production is the leading natural gas producer in the United States, based on average daily sales volumes, with 21.4 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 4.0 million gross acres, including approximately 1.1 million gross acres in the Marcellus play, many of which have associated deep Utica or Upper Devonian drilling rights, and approximately 0.1 million gross acres in the Ohio Utica as of December 31, 2017. EQM Gathering and EQM 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 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. RMP Gathering provides natural gas gathering services to the Company in the dry gas core of the Marcellus Shale in southwestern Pennsylvania,through Rice Midstream Partners LP (RMP) (NYSE: RMP). RMP Water provides water services that support well completion activities and collects and recycles or disposes of flowback and produced water for the Company and third parties in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio also through RMP.

On November 13, 2017, the Company completed its acquisition of Rice Energy Inc. (Rice) pursuant to the Agreement and Plan of Merger, dated as of June 19, 2017 (as amended, the Merger Agreement), by and among the Company, Rice and a wholly owned indirect subsidiary of the Company (Merger Sub). Pursuant to the terms of the Merger Agreement, on November 13, 2017, Merger Sub merged with and into Rice (the Rice Merger) with Rice continuing as the surviving corporation in the Rice Merger. Immediately after the effective time of the Rice Merger (the Effective Time), Rice was merged with and into another wholly owned indirect subsidiary of the Company.

The Company acquired a total of approximately 270,000 net acres through the Rice Merger, which includes approximately 205,000 net Marcellus acres, as well as approximately 65,000 net Utica acres in Ohio. The Company also acquired Upper Devonian and Utica drilling rights held in Pennsylvania. In addition, the Company acquired a 28% limited partner interest, all of the incentive distribution rights (IDRs) and the entire non-economic general partner interest in RMP, as well as certain retained gathering assets located in Belmont and Monroe Counties, Ohio (the Rice retained gathering assets). See Note 2 to the Consolidated Financial Statements for additional information related to the Rice Merger.

In 2015, the Company formed EQT GP Holdings, LP (EQGP) (NYSE: EQGP), a Delaware limited partnership, to own the Company's partnership interests in EQM. As of December 31, 2017, the Company owned the entire non-economic general partner interest and a 90.1% limited partner interest, in EQGP. As of December 31, 2017, EQGP's only cash-generating assets were the following EQM partnership interests: a 26.6% limited partner interest in EQM; a 1.8% general partner interest in EQM; and all of EQM's IDRs. The Company is the ultimate parent company of EQGP, EQM and RMP.

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

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Key Events in 2017

With the completion of the Rice Merger, the Company became the leading natural gas producer in the United States based on average daily sales volumes. Other significant events in 2017 for EQT included:

- EQT achieved record annual production sales volumes, including a 17% increase in total sales volumes and a 17% increase in Marcellus sales volumes. Average realized price increased 23% to $3.04 per Mcfe in 2017 from $2.47 per Mcfe in 2016.

- On February 1, 2017, the Company acquired approximately 14,000 net Marcellus acres located in Marion, Monongalia and Wetzel Counties, West Virginia from a third party for $132.9 million.

- On February 27, 2017, the Company acquired approximately 85,000 net Marcellus acres, including drilling rights on approximately 44,000 net Utica acres, from Stone Energy Corporation for $523.5 million. The acquired acres are primarily located in Wetzel, Marshall, Tyler and Marion Counties, West Virginia. The acquired assets also included 174 operated Marcellus wells and 20 miles of gathering pipeline.

- On June 30, 2017, the Company acquired approximately 11,000 net Marcellus acres, and the associated Utica drilling rights, from a third party for $83.7 million. The acquired acres are primarily located in Allegheny, Washington and Westmoreland Counties, Pennsylvania.

- On October 4, 2017, the Company completed the public offering of $3.0 billion principal amount of notes. The Company used the net proceeds from the sale of the notes to fund a portion of the cash consideration for the Rice Merger, to pay expenses related to the Rice Merger and related transactions, to redeem $700 million aggregate principal amount of Company indebtedness due in 2018 and for other general corporate purposes.

- On October 13, 2017, the FERC issued the Certificate of Public Convenience and Necessity for Mountain Valley Pipeline, LLC (MVP Joint Venture).

Business Segments

Prior to the Rice Merger, the Company reported its results of operations through three business segments: EQT Production, EQT Gathering and EQT Transmission. 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, 2017. Following the Rice Merger, the Company adjusted its internal reporting structure to incorporate the newly acquired assets. The Company now conducts its business through five business segments: EQT Production, EQM Gathering (formerly known as EQT Gathering), EQM Transmission (formerly known as EQT Transmission), RMP Gathering and RMP Water. The EQT Production segment incorporates the Company’s production activities, including those acquired in the Rice Merger, the Company's marketing operations, and certain gathering operations primarily supporting the Company's production activities, including the Rice retained gathering assets. The EQM Gathering segment and the EQM Transmission segment include all of the Company's assets and operations that are owned by EQM; therefore, the financial and operational disclosures related to EQM Gathering and EQM 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, 2017. The RMP Gathering segment contains the Company's gathering assets that are owned by RMP. The RMP Water segment contains the Company's water pipelines, impoundment facilities, pumping stations, take point facilities and measurement facilities owned by RMP. Following the Rice Merger, the financial and operational disclosures related to RMP Gathering and RMP Water will be the same as RMP’s successor disclosures in its Annual Report on Form 10-K for the year ended December 31, 2017.

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The following illustration depicts EQT's consolidated acreage position along with its gathering and transmission systems:

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EQT Production Business Segment

EQT Production holds 21.4 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 4.0 million gross acres, including approximately 1.1 million gross acres in the Marcellus play, many of which also include associated deep Utica or Upper Devonian drilling rights, and approximately 0.1 million gross acres in the Ohio Utica, as of December 31, 2017. 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 59% in 2017, primarily as a result of acquisitions. The Company's Marcellus assets constituted approximately 16.9 Tcfe of the Company's total proved reserves as of December 31, 2017.

As of December 31, 2017, the Company's proved reserves were as follows:

(Bcfe)	Marcellus	Upper Devonian	Ohio Utica	Other	Total
Proved Developed	8,092	683	757	1,767	11,299
Proved Undeveloped	8,805	293	1,049	—	10,147
Total Proved Reserves	16,897	976	1,806	1,767	21,446

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 2018 production guidance, the remaining reserve life of the Company's total proved reserves, as calculated by dividing total proved reserves by 2018 produced volumes guidance, is 14 years.

The Company invested approximately $1,385 million on well development during 2017, with total production sales volumes of 887.5 Bcfe, an increase of 17% over the previous year. EQT Production expects to spend approximately $2.2 billion for well development (primarily drilling and completion) in 2018, which is expected to support the drilling of approximately 195 gross wells, including 134 Marcellus wells, 16 Upper Devonian wells and 45 Ohio Utica wells. The Company also intends to spend approximately $0.2 billion for acreage fill-ins, bolt-on leasing, and other items. 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,		
	2017	2016	2015
Gross wells spud:			
Horizontal Marcellus*	193	130	157
Ohio Utica	7	—	—
Other	1	5	4
Total	201	135	161
Capital expenditures for well development (in millions):			
Horizontal Marcellus*	$1,295	$686	$1,527
Ohio Utica	31	—	—
Other	59	97	143
Total	$1,385	$783	$1,670

* Includes Upper Devonian formations.

The EQT Production segment also includes the following gathering assets which are not owned by EQM or RMP:

- approximately 152 miles of high pressure gathering lines and 4 compressor stations in Belmont and Monroe County, Ohio as of December 31, 2017;

- Strike Force Midstream Holdings LLC's (Strike Force Holdings) 75% membership interest in Strike Force Midstream LLC (Strike Force Midstream), which owns approximately 67 miles of high pressure gathering lines and 2 compressor stations in Belmont and Monroe County, Ohio, as of December 31, 2017; and

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- approximately 6,600 miles of gathering lines that primarily support the Company's and third party production operations in non-core areas of declining production.

Third party revenues for these gathering services are included in pipeline and net marketing services revenues for the EQT Production segment and were approximately $30.8 million for the year ended December 31, 2017, inclusive of third party revenues during the period of November 13, 2017 through December 31, 2017 for EQT Production including the Rice retained gathering assets.

The Company optimizes its transportation and processing assets to sell natural gas and NGLs to marketers, utilities and industrial customers within its operational footprint and in markets available through the Company's current transportation portfolio. The Company provides marketing services for the benefit of EQT Production and third parties and manages approximately 2.4 Bcf per day of firm third party contractual pipeline takeaway capacity and 685 MMcf per day of firm third party processing capacity. The Company has also committed to 1.29 Bcf per day of firm capacity on the MVP (defined under EQM Transmission) and approximately 0.3 Bcf per day of additional third party contractual takeaway capacity expected to come online in future periods.

EQM Gathering Business Segment

As of December 31, 2017, EQM Gathering included approximately 300 miles of high pressure gathering lines with approximately 2.3 Bcf per day of total firm contracted gathering capacity, compression of approximately 189,000 horsepower and multiple interconnect points with EQM Transmission's transmission and storage system. EQM Gathering's system also included approximately 1,500 miles of FERC-regulated low pressure gathering lines.

In the ordinary course of its business, EQM Gathering pursues gathering expansion projects for affiliates and third party producers. EQM Gathering invested approximately $197 million on gathering projects in 2017 that added 475 MMcf per day of firm gathering capacity in southwestern Pennsylvania. This included the final phase of the header pipeline for Range Resources Corporation (Range Resources), which was placed in-service during the second quarter of 2017. The system now provides total firm gathering capacity of 600 MMcf per day at a total project cost of approximately $240 million. This and other expansion projects, primarily for affiliates, supported increased gathered volumes of 11% and gathering revenues of 14% in 2017. In 2018, EQM Gathering estimates capital expenditures of approximately $300 million on gathering expansion projects, primarily driven by affiliate wellhead and header projects in Pennsylvania and West Virginia, including the Hammerhead project, a 1.2 Bcf per day gathering header connecting Pennsylvania and West Virginia production to the MVP.

EQM Transmission Business Segment

As of December 31, 2017, EQM Transmission's transmission and storage system included an approximately 950-mile FERC-regulated interstate pipeline that connects to seven interstate pipelines and local distribution companies. 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 4.4 Bcf per day and compression of approximately 120,000 horsepower as of December 31, 2017.

In the ordinary course of its business, EQM Transmission pursues transmission projects aimed at profitably increasing system capacity. EQM Transmission invested approximately $111 million on transmission and storage system infrastructure in 2017. Revenues in 2017 increased by approximately $41 million or 12% compared to 2016. In 2018, EQM Transmission will focus on the following transmission projects:

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Mountain Valley Pipeline (MVP). 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, 2017. The 42 inch diameter MVP has a targeted capacity of 2.0 Bcf per day and is estimated to span 300 miles extending from EQM Transmission's existing transmission and storage system in Wetzel County, West Virginia to Pittsylvania County, Virginia providing access to the growing Southeast demand markets. As currently designed, the MVP is estimated to cost a total of approximately $3.5 billion, excluding AFUDC, with EQM funding its proportionate share through capital contributions made to the joint venture. In 2018, EQM expects to provide capital contributions of $1.0 billion to $1.2 billion to the MVP Joint Venture. 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. On October 13, 2017, the FERC issued the Certificate of Public Convenience and Necessity for the project. In January 2018, the MVP Joint Venture received multiple limited notices to proceed from the FERC to begin construction

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activities on certain facilities. The MVP Joint Venture plans to commence construction in the first quarter of 2018. The pipeline is targeted to be placed in-service during the fourth quarter of 2018.

- Transmission Expansion. In 2018, EQM Transmission estimates capital expenditures of approximately $100 million for other transmission expansion projects, primarily attributable to the Equitrans Expansion project. The Equitrans Expansion project is designed to provide north-to-south capacity on the mainline Equitrans system for deliveries to the MVP.

RMP Gathering Business Segment

As of December 31, 2017, RMP Gathering included an approximately 178 mile high pressure dry gas gathering system with approximately 5.1 TBtu per day of gathering capacity and compression capacity of approximately 85,000 horsepower that services the Company and third parties in Washington and Greene Counties, Pennsylvania, with connections to five interstate pipelines.

RMP Water Business Segment

RMP Water's assets include water pipelines, impoundment facilities, pumping stations, take point facilities and measurement facilities used to support well completion activities and to collect and recycle or dispose of flowback and produced water for the Company and third parties in Washington and Greene Counties, Pennsylvania, and Belmont County, Ohio. As of December 31, 2017, RMP Water's Pennsylvania assets provided access to 29.4 MMgal per day of fresh water from the Monongahela River and several other regional water sources, and RMP Water's Ohio assets provided access to 14.0 MMgal per day of fresh water from the Ohio River and several other regional water sources.

Strategy

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

Following the Rice Merger, the Company has significant acreage scale in the core of the Marcellus which will allow EQT to drill considerably longer laterals, realize operational efficiencies and improve overall returns. 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. Development of multi-well pads in conjunction with longer laterals, well spacing, and completion techniques allows EQT to maximize recoveries per acre while reducing the overall environmental surface footprint of the Company’s drilling operations.

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

The Company’s board of directors has formed a committee to evaluate options for addressing the Company’s sum-of-the-parts discount. The board will announce a decision by the end of March, 2018, after considering the committee’s recommendation.

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

No single customer accounted for more than 10% of EQT's total operating revenues for 2017 and 2016. One customer within the EQT Production segment accounted for approximately 10% of EQT's total operating revenues in 2015. 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.

Natural Gas Sales: The Company’s produced natural gas is sold to marketers, utilities and industrial customers located in the Appalachian Basin and in the markets available through the Company's current transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast 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 is lower relative to the price at Henry Hub,

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Louisiana (the location for pricing NYMEX natural gas futures) as a result of the increased supply of natural gas in the Appalachian Basin. 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 7 to the Consolidated Financial Statements.

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 a portion of the Company's NGLs. 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.

The following table presents the average sales price on a 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:

	2017	2016	2015
Average sales price per Mcfe sold (excluding cash settled derivatives)	$2.98	$1.99	$2.38
Average sales price per Mcfe sold (including cash settled derivatives)	$3.04	$2.47	$3.09

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.

EQM Gathering: EQT Production accounted for approximately 89% and 84% of EQM Gathering's gathering revenues and volumes, respectively, for 2017.

EQM provides gathering services in two manners: firm service and interruptible service. The fixed monthly fee under a firm contract is referred to as a firm reservation fee, which is recognized ratably over the contract period based on the contracted volume regardless of the amount of natural gas that is gathered. If there is available system capacity, customers can flow gas above the firm commitment volumes for a usage charge per unit at a rate that is generally the same or lower than the firm capacity charge per unit. EQM has firm gas gathering agreements in high pressure development areas with approximately 2.3 Bcf per day of total firm contracted gathering capacity as of December 31, 2017. Including expected future capacity from expansion projects that are not yet fully constructed but for which EQM had entered into firm gathering agreements, approximately 2.4 Bcf per day of firm gathering capacity was subscribed under firm gathering contracts as of December 31, 2017. On EQM's low pressure regulated gathering system, the typical gathering agreement is interruptible and has a one year term 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. EQM generally does not take title to the natural gas gathered for its customers but retains a percentage of wellhead natural gas receipts to recover natural gas used to run its compressor stations and other requirements on all of its gathering systems.

EQM Transmission: In 2017, EQT Production accounted for approximately 64% of transmission volumes and 53% of transmission revenues for EQM Transmission. Other customers include local distribution companies, marketers, other independent producers and commercial and industrial users. EQM's transmission system provides these customers with access to adjacent markets in Pennsylvania, West Virginia and Ohio and also provides access to the

Mid-Atlantic, Northeastern, Midwestern and Gulf Coast markets in the United States through interconnect capacity with major interstate pipelines.

EQM Transmission generally does not take title to the natural gas transported or stored for its customers. EQM Transmission provides 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, EQM 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.

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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 5.1 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, 2017. EQM Transmission's firm transmission and storage contracts had a weighted average remaining term of approximately 15 years as of December 31, 2017 based on total projected contracted revenues.

As of December 31, 2017, approximately 89% of EQM Transmission's contracted transmission firm capacity was subscribed by customers under negotiated rate agreements under its tariff. Approximately 9% of EQM 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. The remaining 2% of EQM Transmission’s contracted transmission firm capacity was subscribed at discounted rates, which are less than the maximum rates an interstate pipeline may charge for its services under its tariff.

EQM Transmission has an acreage dedication from EQT pursuant to which EQM 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) and Rice Energy Marketing LLC, EQT's indirect wholly owned marketing subsidiaries, provide marketing services and contractual pipeline capacity management for the benefit of EQT Production and third parties. The marketing subsidiaries also engage 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.

RMP Gathering: During the year ended December 31, 2017, EQT and Rice, prior to the Rice Merger, represented substantially all of RMP Gathering’s gathering and compression revenues.

RMP Gathering has secured dedications from certain EQT affiliates under various fixed price per unit gathering and compression agreements covering (i) approximately 246,000 gross acres of EQT's acreage position in Washington and Greene Counties, Pennsylvania, and (ii) subject to certain exceptions and limitations pursuant to the gas gathering and compression agreements, any future acreage certain affiliates of EQT acquire within these counties.

RMP Water Services: During the year ended December 31, 2017, EQT and Rice, prior to the Rice Merger, represented approximately 96% of RMP Water's water service revenues.

RMP Water has the exclusive right to provide certain fluid handling services to EQT Production until December 22, 2029, and from month to month thereafter. The fluid handling services include the exclusive right to provide fresh water for well completions operations and to collect and recycle or dispose of flowback and produced water within areas of dedication in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio. RMP Water also provides water services to third parties under fee-based contracts to support well completion activities.

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 within and outside of the Appalachian Basin.

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.

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Key competitors for water services include natural gas producers that develop their own water distribution systems in lieu of employing the Company's assets and other natural gas midstream companies. Our ability to attract volumes to the water services business depends on the Company's ability to evaluate and select suitable projects and to consummate transactions in a highly competitive environment.

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 allowables on the amount of 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. 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 have not been adopted or implemented, 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 anticipates additional, compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

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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.

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 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 2,067 employees at the end of 2017; 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.

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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,		
	2017	2016	2015
	(Thousands)		
Operating Revenues:			
Sales of natural gas, oil and NGLs (a)	$2,651,318	$1,594,997	$1,690,360
Pipeline, water and net marketing services (b)	336,676	262,342	263,640
Gain (loss) on derivatives not designated as hedges (a)	390,021	(248,991)	385,762
Total operating revenues	$3,378,015	$1,608,348	$2,339,762

(a) Reported in the EQT Production segment.

(b) Reported in the EQM Gathering, EQM Transmission, RMP Gathering and RMP Water segments, with the exception of $65.0 million, $41.0 million and $55.5 million for the years ended December 31, 2017, 2016 and 2015, respectively, which are reported within the EQT Production segment.

Financial Information about Segments

See Note 6 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 daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $3.77 per MMBtu to a low of $1.49 per MMBtu from January 1, 2016 through December 31, 2017, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $60.46 per barrel to a low of $26.19 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 and other market point basis, NGLs and oil and thus cannot predict the ultimate impact of prices on our operations.

Lower prices for natural gas, NGLs and oil result 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 us having to make significant downward adjustments to the value of our assets and could cause us to incur non-cash impairment charges to earnings in future periods. See “Impairment of Oil and Gas Properties and Goodwill” under Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “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, including goodwill and other long lived intangible assets, which could materially and adversely affect our results of operations in future periods.” under Item 1A, “Risk Factors.” 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. Further, adverse economic and market conditions could negatively affect the collectability of our trade receivables and cause our hedge counterparties to be unable to perform their obligations or to seek bankruptcy protection.

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 may not achieve the intended benefits of the acquisition of Rice and the acquisition may disrupt our current plans or operations.

There can be no assurance that we will be able to successfully integrate Rice’s assets or otherwise realize the expected benefits of the acquisition of Rice. In addition, our business may be negatively impacted if we are unable to effectively manage our expanded operations going forward. The integration has required and will continue to require significant time and focus from management and could disrupt current plans and operations, which could delay the achievement of our strategic objectives.

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, completions, producing, transporting and storing natural gas, NGLs and oil, such as well site blowouts, cratering and explosions, pipe and other equipment and system failures, landslides, fires, formations with abnormal or unexpected pressures, freeze offs of wells and pipelines due to cold weather, inadvertent third party damage to the Company's assets, 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 access to pipeline infrastructure within the Appalachian Basin is intense, and our ability to secure access to pipeline infrastructure on economic terms could affect our competitive position. The Company’s investment in midstream infrastructure through EQM and RMP 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, operational efficiency, and construction, and these risks can be affected by the availability of capital, materials and a qualified work force, as well as the complexity of construction locations, weather conditions, 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 vandalism, sabotage or 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 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 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.

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The substantial majority of our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating primarily in one major geographic area.

The substantial majority of our producing properties are geographically concentrated in the Appalachian Basin. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by and costs associated with governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other weather related conditions, interruption of the processing or transportation of oil, natural gas or NGLs and changes in regional and local political regimes and regulations. Such conditions could have a material adverse effect on our financial condition and results of operations.

In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations. For example, third parties may engage in subsurface mining operations near or under our properties, which could cause subsidence or other damage to our properties, adversely impact our drilling operations or adversely impact our midstream activities or those on which we rely.

Due to the concentrated nature of our portfolio of natural gas properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

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 2018 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 2018 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify and execute optimal business strategies, including the appropriate corporate structure and 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 2018 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.

In addition, we announced in late 2017 that our board of directors has formed a committee to evaluate options to address our sum-of-the-parts discount, with the results of such review to be announced by the end of March 2018. There can be no assurance regarding the outcome of this review or how such outcome may affect us.

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

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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 to legal challenges, were to change and if the FERC were to disallow all or a substantial portion of the current income tax allowance for EQM's pipelines, including adjusting the income tax allowance for reduced income tax rates enacted by the Tax Cuts and Jobs Act of 2017, 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 approximately $200,000 per day for each violation up to a maximum penalty of approximately $2 million 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.

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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.

Subsequent to the broad tax reform changes provided in the law known as the Tax Cuts and Job Act of 2017, other tax law changes could be enacted that have a material impact on us. The most significant potential tax law change would be a full or partial elimination of the ability to expense intangible drilling costs, or a linking of that deduction to the deduction for interest expense, either of which could adversely impact both current and deferred federal and state income tax liabilities. The cash cost of any such change could impact our ability to 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 could change, such as the change resulting from the law known as the Tax Cuts and Jobs Act of 2017. Any such increase or change or varying interpretations of these laws, including the imposition of a new severance tax (a tax on the extraction of natural resources) in states in which we produce gas, could adversely impact our earnings, cash flows and financial position.

In 2010, the U.S. Congress adopted the Dodd-Frank Act which established federal oversight and regulation of the over-the-counter derivative market and entities, such as us, that participate in that market. 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 have not been adopted or implemented, 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.

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

We, EQM and RMP 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, EQM's or RMP's business and financial condition. Our, EQM's and RMP's ability to access the capital markets may be restricted at a time when we, EQM or RMP desire, or need, to raise capital, which could have an impact on our, EQM's, or RMP's flexibility to react to changing economic and business conditions or our ability to implement our business strategies.

As of February 15, 2018, our Senior Notes were rated “Baa3” by Moody’s Investors Services (Moody’s), “BBB” by Standard & Poor’s Ratings Service (S&P) with a "negative" outlook, and “BBB-” by Fitch Ratings Service (Fitch), and EQM's Senior Notes were 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 Senior Notes, 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 Senior Notes. 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, a 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

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us. In addition, the success of our operations will depend, in part, on our ability to identify, 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 identifying, attracting and retaining such personnel. If we cannot identify, 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 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.

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, including goodwill and other long lived intangible 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, midstream assets and goodwill for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. In addition, we evaluate goodwill for impairment at least annually. 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

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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 to our proved oil and gas properties in the non-core Permian basin during 2015. 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, including goodwill and other long lived intangible 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, 2017. Any impairment of our assets, including goodwill and other long lived intangible assets, would require us to take an immediate charge to earnings. Such charges could be material to our results of operations and could adversely impact our financial condition and results of operations. See “Impairment of Oil and Gas Properties and Goodwill” 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

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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, Ohio, Kentucky and Virginia. This segment has approximately 4.0 million gross acres (approximately 72% 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. Of these gross acres, approximately 1.1 million are in the Marcellus play, many of which have associated deep Utica or Upper Devonian drilling rights, and approximately 0.1 million are in the Ohio Utica. 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, 2017, the Company estimated its total proved reserves to be 21.4 Tcfe, consisting of proved developed producing reserves of 11.1 Tcfe, proved developed non-producing reserves of 0.2 Tcfe and proved undeveloped reserves of 10.1 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
in Petroleum and Natural Gas Engineering from The Pennsylvania State University and has 29 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, 2017. Ryder Scott conducted a detailed, well by well, audit of the Company's largest properties. This audit covered 81% of the Company's proved developed reserves. Ryder Scott's audit of the remaining approximately 19% of the Company's proved developed properties consisted of an audit of aggregated groups not exceeding 200 wells per case for operated wells and 256 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 2017, the Company commenced drilling operations (spud or drilled) on 144 gross horizontal Marcellus wells, 49 gross horizontal Upper Devonian wells, seven gross horizontal Ohio Utica wells and one other gross well. Total proved reserves in the Marcellus play increased 51% to 16.9 Tcfe in 2017 primarily as a result of the Company's acquisition and drilling activity. Production sales volumes in 2017 from the Marcellus, including the Upper Devonian play, was 770.6 Bcfe. Over the past five years, the Company has experienced a 97% developmental drilling success rate.

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Natural gas, NGLs and crude oil pricing:

	For the Years Ended December 31,		
	2017	2016	2015
Natural Gas:			
Average sales price (excluding cash settled derivatives) ($/Mcf)	$ 2.82	$ 1.88	$ 2.28
Average sales price (including cash settled derivatives) ($/Mcf)	$ 2.89	$ 2.41	$ 3.06
NGLs (excluding ethane):			
Average sales price (excluding cash settled derivatives) ($/Bbl)	$ 31.59	$ 19.43	$ 18.84
Average sales price (including cash settled derivatives) ($/Bbl)	$ 30.90	$ 19.43	$ 18.84
Ethane:			
Average sales price ($/Bbl) (a)	$ 6.32	$ 5.08	$ —
Crude Oil:			
Average sales price ($/Bbl)	$ 40.70	$ 34.73	$ 38.70

(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 2017, 2016 and 2015 was $0.13 per Mcfe, $0.15 per Mcfe and $0.19 per Mcfe, respectively. At December 31, 2017, the Company had approximately 50 multiple completion wells.

	Natural Gas	Oil
Total productive wells at December 31, 2017:		
Total gross productive wells	14,498	108
Total net productive wells	13,596	104
Total in-process wells at December 31, 2017:	0	
Total gross in-process wells	413	—
Total net in-process wells	368	—

Summary of proved natural gas, oil and NGL reserves as of December 31, 2017 based on average fiscal year prices:

	Natural Gas (MMcf)	Oil and NGLs (Bbls)
Developed	10,152,543	190,901
Undeveloped	9,677,693	78,337
Total proved reserves	19,830,236	269,238

Total acreage at December 31, 2017:	
Total gross productive acres	1,126,606
Total net productive acres	1,058,833
Total gross undeveloped acres	2,872,468
Total net undeveloped acres	2,586,586

As of December 31, 2017, the Company had no proved undeveloped reserves that had remained undeveloped for more than five years.

As of December 31, 2017, leases associated with approximately 92,000 gross undeveloped acres expire in 2018 if they are not renewed. The Company has an active lease renewal program in areas targeted for development. Within the

Marcellus formation, the Company must drill one well in 2018 under a lease and acquisition agreement or 139 net acres will be at-risk.

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

	For the Years Ended December 31,		
	2017	2016	2015
Exploratory wells:			
Productive	—	—	1.0
Dry	1.0	—	1.0
Development wells:			
Productive	149.2	140.9	234.5
Dry	4.9	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, 2017 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	Ohio	Other (b)	Total
Natural gas, oil and NGLs production (MMcfe) – 2017 (a) (c)	456,614	352,481	60,423	24,426	13,948	907,892
Natural gas, oil and NGLs production (MMcfe) – 2016 (a)	426,524	272,529	61,267	541	15,502	776,363
Natural gas, oil and NGLs production (MMcfe) – 2015 (a)	327,616	208,376	65,726	859	16,109	618,686
Natural gas, oil and NGLs sales (MMcfe) – 2017 (c)	456,600	343,199	51,313	24,113	12,295	887,520
Natural gas, oil and NGLs sales (MMcfe) – 2016	429,011	264,452	51,200	536	13,768	758,967
Natural gas, oil and NGLs sales (MMcfe) – 2015	329,626	200,121	57,825	758	14,752	603,082
Average net revenue interest of proved reserves (%)	79.7 %	83.0 %	92.7 %	46.6 %	79.8 %	76.4 %
Total gross productive wells	1,654	5,391	5,723	178	1,660	14,606
Total net productive wells	1,595	5,125	5,412	78	1,490	13,700
Total gross productive acreage	189,302	329,357	438,598	40,878	128,471	1,126,606
Total gross undeveloped acreage	502,534	1,069,017	1,057,288	49,207	194,422	2,872,468
Total gross acreage	691,836	1,398,374	1,495,886	90,085	322,893	3,999,074
Total net productive acreage	180,714	321,110	432,007	22,761	102,241	1,058,833
Total net undeveloped acreage	486,232	898,592	985,424	49,258	167,080	2,586,586
Total net acreage	666,946	1,219,702	1,417,431	72,019	269,321	3,645,419
(Amounts in Bcfe)						
Proved developed producing reserves	5,569	3,449	1,226	700	162	11,106
Proved developed non-producing reserves	122	13	—	58	—	193
Proved undeveloped reserves	7,786	1,313	—	1,048	—	10,147
Proved developed and undeveloped reserves	13,477	4,775	1,226	1,806	162	21,446
Gross proved undeveloped drilling locations	574	126	—	107	—	807
Net proved undeveloped drilling locations	539	124	—	70	—	733

(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 Virginia, Maryland and Texas.

(c) For the year ended December 31, 2017, the natural gas, oil and NGLs production volumes and sales volumes includes volumes from the production operations acquired in the Rice Merger for the period of November 13, 2017 through December 31, 2017.

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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, 2017, the Company's delivery commitments for the next five years were as follows:

For the Year Ended December 31,	Natural Gas (Bcf)
2018	1,173
2019	671
2020	459
2021	335
2022	259

Capital expenditures at EQT Production totaled $2.4 billion during 2017, including $1.0 billion for the acquisition of properties. The Company invested approximately $1,055.7 million during 2017 developing proved reserves and approximately $329.2 million on wells still in progress at year end. During the year ended December 31, 2017, the Company converted approximately 987 Bcfe of proved undeveloped reserves to proved developed reserves. The Company had additions to proved developed reserves of 4,455 Bcfe, including 3,330 Bcfe from acquired wells and 300 Bcfe from wells developed in 2017 that had not previously been classified as proved. The Company had negative revisions of 3,074 Bcfe of proved undeveloped reserves that are no longer anticipated to be drilled within 5 years of booking as a result of acquiring new acreage, which added 6,060 Bcfe of proved undeveloped reserves. The acquired acreage presents opportunities to drill considerably longer laterals, realize operational efficiencies and improve overall returns. As of December 31, 2017, the Company's proved undeveloped reserves totaled 10.1 Tcfe, 90% 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 2017 extensions, discoveries and other additions totaled 2,225 Bcfe, which exceeded the 2017 production of 908 Bcfe. Of these reserves, 1,925 Bcfe are attributed to the addition of proved undeveloped locations in the Company's Pennsylvania and West Virginia Marcellus fields and 300 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 7,700 feet. Wells located in Kentucky are primarily in Huron formations with depths ranging from 2,500 feet to 6,500 feet. Wells located in Ohio are primarily in Utica formations with depths ranging from 8,500 feet to 10,500 feet. Other wells are in Coalbed Methane, deep Utica and Permian formations.

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 gathering assets, including the Rice retained gathering assets and certain non-core gathering operations primarily supporting the Company's production operations. See "EQT Production Business Segment" under Item 1, "Business" for a description of the midstream assets included in the EQT Production segment, which is incorporated herein by reference. 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, Ohio, Virginia, Kentucky and Texas.

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

For a description of material properties, see "EQM Gathering Business Segment," "EQM Transmission Business Segment," "RMP Gathering Business Segment" and "RMP Water Business Segment" under Item 1, "Business," which sections are incorporated herein by reference.

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 condition, 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. 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. The PADEP appealed that decision to the Pennsylvania Supreme Court, and the parties made oral arguments in front of the Pennsylvania Supreme Court on November 28, 2017. Following a July 2016 hearing before the EHB, in May 2017, the EHB ruled that the Company should pay $1.1 million in civil penalties. In June 2017, both the Company and the PADEP appealed the EHB’s decision to the Commonwealth 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 condition, 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 Allegheny Valley Connector (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 October 2016, EQM acquired the AVC facilities from EQT, including any future obligations related to these releases. In February 2017, EQM received a proposed consent assessment of civil penalty from the PADEP that proposed a civil penalty related to the NOVs. 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 condition, results of operations or liquidity of the Company or EQM.

Trans Energy, Inc. Matter, West Virginia

As described in Note 10 to the Consolidated Financial Statements, the Company completed the acquisition of Trans Energy, Inc. (Trans Energy) on December 5, 2016. 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 U.S. Environmental Protection Agency (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 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, pursuant to a plea agreement, Trans Energy pleaded guilty to three misdemeanor charges filed by the U.S. 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.

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 EPA terminated the Administrative Agreement effective as of October 25, 2017. The Administrative Agreement required, 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.

Fresh Water Pipeline Bore Release, Allegheny County, Pennsylvania

On February 24, 2017, the Company received an NOV from the PADEP. The NOV alleged violations of the Pennsylvania Oil and Gas Act and Clean Streams Law related to an unintentional release, by a Company vendor, of mine water into the Monongahela River in January 2017 from a mine void that was pierced while boring under a road for the installation of a fresh water pipeline in Allegheny County, Pennsylvania. The Company cooperated with the PADEP to take appropriate actions to stop the release. On February 15, 2017, the Company entered into a civil penalty settlement related to the release with the Pennsylvania Fish and Boat Commission for $4,555 for alleged violations of the Pennsylvania Fish and Boat Code. Settlement discussions between the Company and the PADEP are ongoing. While the Company expects the PADEP's claims to 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 condition, results of operations or liquidity of the Company.

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 a number of 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 15, 2018)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Jeremiah J. Ashcroft III (45)	Senior Vice President, EQT Corporation and President, Midstream (2017)	Elected to present position August 2017. Mr. Ashcroft is also a Director and Senior Vice President and Chief Operating Officer of each of EQT Midstream Services, LLC, the general partner of EQM, since August 2017, and Rice Midstream Management LLC, the general partner of RMP, since November 2017. Prior to joining EQT Corporation, Mr. Ashcroft served as President and Chief Executive Officer of Gulf Oil L.P., from September 2015 to June 2017; Executive Vice President and Chief Operating Officer of JP Energy Partners, LP, from May 2014 to September 2015; and President of Buckeye Partners, L.P.'s Natural Gas Storage, Development & Logistics and Energy Services business units, from January 2012 to May 2014.
Lewis B. Gardner (60)	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, EQT GP Services, LLC, the general partner of EQGP, since January 2015, and Rice Midstream Management LLC, the general partner of RMP, since November 2017.
Donald M. Jenkins (45)	Chief Commercial Officer (2017)	Elected to present position March 2017. Mr. Jenkins served as Executive Vice President, Commercial, EQT Energy, LLC, from May 2014 to February 2017; and Senior Vice President, Trading and Origination, EQT Energy, LLC, from December 2012 to May 2014.
Robert J. McNally (47)	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, the general partner of EQM, since March 2016, EQT GP Services, LLC, the general partner of EQGP, since March 2016, and Rice Midstream Management LLC, the general partner of RMP, since November 2017. 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 (57)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007.
David L. Porges (60)	Executive Chairman (1998)	Elected to present position March 2017. Mr. Porges served as Chairman and Chief Executive Officer, EQT Corporation, from December 2015 to February 2017; Chairman, President, and Chief Executive Officer, EQT Corporation, from May 2011 to December

		2015; and President and Chief Executive Officer of each of EQT Midstream Services, LLC, the general partner of EQM, from January 2012 to February 2017, and EQT GP Services, LLC, the general partner of EQGP, from January 2015 to February 2017. Mr. Porges has served as a Director of the Company since May 2002 and also Chairman of the Boards of Directors of the general partners of EQGP, EQM and RMP, since January 2015, January 2012 and November 2017, respectively. As previously disclosed in the Company's Form 8-K filed with the SEC on January 18, 2018, Mr. Porges intends to retire from his position as Executive Chairman of the Company on February 28, 2018. Following that time, he will continue to serve as a non-executive Chairman of the Company's Board of Directors.
David E. Schlosser, Jr. (52)	Senior Vice President, EQT Corporation and President, Exploration and Production (2017)	Elected to present position March 2017. Mr. Schlosser served as Executive Vice President, Engineering, Geology and Planning, EQT Production Company, from October 2014 to February 2017; and Senior Vice President, Engineering and Strategic Planning, EQT Production Company, from March 2012 to September 2014.
Steven T. Schlotterbeck (52)	President and Chief Executive Officer (2008)	Elected to present position March 2017. Mr. Schlotterbeck served as President, EQT Corporation and President, Exploration and Production from December 2015 to February 2017; Executive Vice President, EQT Corporation and President, Exploration and Production from December 2013 to December 2015; and Senior Vice President, EQT Corporation and President, Exploration and Production from April 2010 to December 2013. Mr. Schlotterbeck has also served as President and Chief Executive Officer of each of EQT GP Services, LLC, the general partner of EQGP, since March 2017, EQT Midstream Services, LLC, the general partner of EQM, since March 2017, and Rice Midstream Management LLC, the general partner of RMP, since November 2017. Mr. Schlotterbeck is also a Director of each of EQT Corporation, since January 2017, EQT GP Services, LLC, since January 2015, EQT Midstream Services, LLC, since January 2017, and Rice Midstream Management LLC, since November 2017.
Jimmi Sue Smith (45)	Chief Accounting Officer (2016)	Elected to present position September 2016. Ms. Smith served as Vice President and Controller of the Company's midstream and commercial businesses from March 2013 to September 2016; and Vice President and Controller of the Company's midstream business from January 2013 through March 2013. Ms. Smith is also Chief Accounting Officer of each of EQT Midstream Services, LLC, the general partner of EQM, since September 2016, EQT GP Services, LLC, the general partner of EQGP, since September 2016, and Rice Midstream Management LLC, the general partner of RMP, since November 2017.

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 2017 and 2016 are summarized as follows (in U.S. dollars per share):

	2017			2016		
	High	Low	Dividend	High	Low	Dividend
1st Quarter	$66.41	$56.33	$ 0.03	$68.26	$48.30	$ 0.03
2nd Quarter	64.45	49.63	0.03	80.61	63.48	0.03
3rd Quarter	67.84	57.49	0.03	79.64	67.69	0.03
4th Quarter	66.03	53.43	0.03	75.74	63.11	0.03

As of January 31, 2018, there were 2,358 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, 2017:

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 2017 (October 1 – October 31)	—	$ —	—	700,000
November 2017 (November 1 – November 30)	788,066	65.15	—	700,000
December 2017 (December 1 – December 31)	53,443	64.62	—	700,000
Total	841,509	$ 65.11	—	

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

(b) On April 30, 2014, the Company’s Board of Directors announced 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, 2017, 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 cumulative returns of the S&P 500 Index and a customized peer group. The individual companies of the prior customized peer group (the 2016 Self-Constructed Peer Group) and the new customized peer group (the 2017 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, 2012 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, 2017.

	12/12	12/13	12/14	12/15	12/16	12/17
EQT Corporation	$100.00	$152.46	$128.71	$88.77	$111.58	$97.30
S&P 500	100.00	132.39	150.51	152.59	170.84	208.14
2016 Self-Constructed Peer Group (a)	100.00	139.77	116.14	73.35	109.56	103.76
2017 Self-Constructed Peer Group (b)	100.00	137.94	115.12	71.23	105.10	98.82

(a) The 2016 Self-Constructed Peer Group includes the following 21 companies: Cabot Oil & Gas Corp, Chesapeake Energy Corp, Cimarex Energy Co, Concho Resources Inc., CONSOL Energy Inc. (now known as CNX Resources Corp), 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, Southwestern Energy Co, Ultra Petroleum Corp and Whiting Petroleum Corp. Spectra Energy Corp was 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, 2016 but has been excluded from the 2016 Self-Constructed Peer Group above as it was acquired.

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(b) The 2017 Self-Constructed Peer Group includes the following 22 companies: Antero Resources Corp, Cabot Oil & Gas Corp, Chesapeake Energy Corp, Cimarex Energy Co, Concho Resources Inc., CONSOL Energy Inc. (now known as CNX Resources Corp), Continental Resources Inc., Devon Energy Corp, 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, Southwestern Energy Co, and Whiting Petroleum Corp. The 2017 Self-Constructed Peer Group is the peer group that is used for the Company's 2017 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 2016 Self-Constructed Peer Group after adjusting for the removal of Spectra Energy Corp (acquired) and Ultra Petroleum Corp (filed for bankruptcy) and the addition of Antero Resources Corp and Devon Energy Corp (determined by the Company's Management Development and Compensation Committee (the Compensation Committee) to be appropriate peers).

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,				
	2017	2016	2015	2014	2013
	(Thousands, except per share amounts)				
Total operating revenues	$3,378,015	$1,608,348	$2,339,762	$2,469,710	$1,862,011
Amounts attributable to EQT Corporation:					
Income (loss) from continuing operations	$1,508,529	$(452,983)	$85,171	$385,594	$298,729
Net income (loss)	$1,508,529	$(452,983)	$85,171	$386,965	$390,572
Earnings per share of common stock attributable to EQT Corporation:					
Basic:					
Income (loss) from continuing operations	$8.05	$(2.71)	$0.56	$2.54	$1.98
Net income (loss)	$8.05	$(2.71)	$0.56	$2.55	$2.59
Diluted:					
Income (loss) from continuing operations	$8.04	$(2.71)	$0.56	$2.53	$1.97
Net income (loss)	$8.04	$(2.71)	$0.56	$2.54	$2.57
Total assets	$29,522,604	$15,472,922	$13,976,172	$12,035,353	$9,765,907
Long-term debt	$7,331,554	$3,289,459	$2,793,343	$2,959,353	$2,475,370
Cash dividends declared per share of common stock	$0.12	$0.12	$0.12	$0.12	$0.12

See Item 1A, “Risk Factors”, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Notes 1, 2, 9 and 10 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 Operations

2017 EQT Highlights:

- Closed the Rice Merger on November 13, 2017
- Achieved annual production sales volumes of 887.5 Bcfe, 17% higher than 2016
- Completed the 2017 Notes Offering (defined in Note 15 to the Consolidated Financial Statements) totaling $3.0 billion
- Received FERC Certificate for Mountain Valley Pipeline

Net income attributable to EQT Corporation for 2017 was $1,508.5 million, $8.04 per diluted share, compared with a loss attributable to EQT Corporation of $453.0 million, a loss of $2.71 per diluted share, in 2016. The $1,961.5 million increase in net income attributable to EQT Corporation was primarily attributable to an income tax benefit recorded as a result of the lower federal corporate tax rate beginning in 2018, the result of a gain on derivatives not designated as hedges in 2017 compared to a loss in 2016, a 23% increase in the average realized price, a 17% increase in production sales volumes, and higher pipeline, water and net marketing services, partially offset by higher operating expenses, higher interest expense, higher net income attributable to noncontrolling interests and a loss on debt extinguishment in 2017.

During the year ended December 31, 2017, the Company recorded acquisition expenses of approximately $237.3 million related to the Rice Merger, including $141.3 million of employee related expenses for payments to former Rice employees under the Merger Agreement. Additional expenses were for investment banking, legal and other professional fees. Acquisition costs are reflected in unallocated expenses and not recorded on any operating segment.

EQT Production received $40.7 million and $279.4 million of net cash settlements for derivatives not designated as hedges for the years ended December 31, 2017 and 2016, respectively, that are included in the average realized price but are not in GAAP operating revenues.

Net loss attributable to EQT Corporation for 2016 was $453.0 million, a loss of $2.71 per diluted share, compared with net income attributable to EQT Corporation of $85.2 million, $0.56 per diluted share, in 2015. The $538.2 million decrease in income 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, 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.

See “Business Segment Results of Operations” for a discussion of items impacting operating income, “Other Income Statement Items” for a discussion of other income, interest expense, income taxes 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 Production total operating revenues. See “Reconciliation of Non-GAAP Financial Measures” for a reconciliation of EQT Production

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adjusted operating revenues to EQT Production total operating revenues and Note 6 to the Consolidated Financial Statements for a reconciliation of EQT Production total operating revenues to EQT Corporation total operating revenues.

	Years Ended December 31,		
in thousands (unless noted)	2017 (e)	2016	2015
NATURAL GAS			
Sales volume (MMcf)	774,076	683,495	547,094
NYMEX price ($/MMBtu) (a)	$3.09	$2.47	$2.66
Btu uplift	$0.27	$0.22	$0.25
Natural gas price ($/Mcf)	$3.36	$2.69	$2.91
Basis ($/Mcf) (b)	(0.54)	(0.81)	(0.63)
Cash settled basis swaps (not designated as hedges) ($/Mcf)	$0.01	$0.09	$0.03
Average differential, including cash settled basis swaps ($/Mcf)	$(0.53)	$(0.72)	$(0.60)
Average adjusted price ($/Mcf)	$2.83	$1.97	$2.31
Cash settled derivatives (cash flow hedges) ($/Mcf)	0.01	0.13	0.47
Cash settled derivatives (not designated as hedges) ($/Mcf)	0.05	0.31	0.28
Average natural gas price, including cash settled derivatives ($/Mcf)	$2.89	$2.41	$3.06
Natural gas sales, including cash settled derivatives	$2,237,234	$1,649,831	$1,671,562
LIQUIDS			
NGLs (excluding ethane):			
Sales volume (MMcfe) (c)	74,060	57,243	51,530
Sales volume (Mbbls)	12,343	9,540	8,588
Price ($/Bbl)	$31.59	$19.43	$18.84
Cash settled derivatives (not designated as hedges) ($/Bbl)	(0.69)	—	—
Average NGL price, including cash settled derivatives ($/Bbl)	$30.90	$19.43	$18.84
NGLs sales	$381,327	$185,405	$161,775
Ethane:			
Sales volume (MMcfe) (c)	33,432	13,856	—
Sales volume (Mbbls)	5,572	2,309	—
Price ($/Bbl)	$6.32	$5.08	$—
Ethane sales	$35,241	$11,742	$—
Oil:			
Sales volume (MMcfe) (c)	5,952	4,373	4,458
Sales volume (Mbbls)	992	729	743
Price ($/Bbl)	$40.70	$34.73	$38.70
Oil sales	$40,376	$25,312	$28,752
Total liquids sales volume (MMcfe) (c)	113,444	75,472	55,988
Total liquids sales volume (Mbbls)	18,907	12,578	9,331
Liquids sales	$456,944	$222,459	$190,527
TOTAL PRODUCTION			
Total natural gas & liquids sales, including cash settled derivatives (d)	$2,694,178	$1,872,290	$1,862,089
Total sales volume (MMcfe)	887,520	758,967	603,082

Average realized price ($/Mcfe)	$3.04	$2.47	$3.09

(a) The Company's volume weighted NYMEX natural gas price (actual average NYMEX natural gas price ($/MMBtu) was $3.11, $2.46 and $2.66 for the years ended December 31, 2017, 2016 and 2015, 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.

(e) For the year ended December 31, 2017, EQT Production includes the results of production operations acquired in the Rice Merger for the period of November 13, 2017 through December 31, 2017.

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Reconciliation of Non-GAAP Financial Measures

The table below reconciles EQT Production adjusted operating revenues, a non-GAAP supplemental financial measure, to EQT Production total operating revenues as reported under EQT Production Results of Operations, its most directly comparable financial measure calculated in accordance with GAAP. See Note 6 to the Consolidated Financial Statements for a reconciliation of EQT Production operating revenues to EQT Corporation total operating revenues as reported in the Statements of Consolidated Operations.

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)	2017	2016	2015
EQT Production total operating revenues	$3,106,337	$1,387,054	$2,131,664
(Deduct) add back:			
(Gain) loss on derivatives not designated as hedges	(390,021)	248,991	(385,762)
Net cash settlements received on derivatives not designated as hedges	40,728	279,425	172,093
Premiums received (paid) for derivatives that settled during the year	2,132	(2,132)	(364)
Pipeline and net marketing services	(64,998)	(41,048)	(55,542)
EQT Production adjusted operating revenues, a non-GAAP financial measure	$2,694,178	$1,872,290	$1,862,089
Total sales volumes (MMcfe)	887,520	758,967	603,082
Average realized price ($/Mcfe)	$3.04	$2.47	$3.09

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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 2017, unallocated expenses also included the Rice Merger acquisition related expenses of $237.3 million, including $141.3 million of employee related expenses for payments to former Rice employees under the Merger Agreement as well as investment banking, legal and other professional fees. In 2016, unallocated expenses also included an impairment of long-lived assets of approximately $59.7 million related to certain gathering assets sold to EQM in October 2016.

The Company has reported the components of each segment's operating income 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 6 to the Consolidated Financial Statements.

Prior to the Rice Merger, the Company reported its results of operations through three business segments: EQT Production, EQT Gathering and EQT Transmission. 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, 2017. Following the Rice Merger, the Company adjusted its internal reporting structure to incorporate the newly acquired assets. The Company now conducts its business through five business segments: EQT Production, EQM Gathering (formerly known as EQT Gathering), EQM Transmission (formerly known as EQT Transmission), RMP Gathering and RMP Water. The EQT Production segment includes the Company's production activities, including those acquired in the Rice Merger, the Company's marketing operations and certain gathering operations primarily supporting the Company's production activities, including the Rice retained gathering assets. The EQM Gathering segment and the EQM Transmission segment include all of the Company's assets and operations that are owned by EQM; therefore, the financial and operational disclosures related to EQM Gathering and EQM 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, 2017. The RMP Gathering segment contains the Company's gathering assets that are owned by RMP. The RMP Water segment contains the Company's water pipelines, impoundment facilities, pumping stations, take point facilities and measurement facilities owned by RMP. Following the Rice Merger, the financial and operational disclosures related to RMP Gathering and RMP Water will be the same as RMP's successor disclosures in its Annual Report on Form 10-K for the year ended December 31, 2017.

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EQT Production

Results of Operations

	Years Ended December 31,				
	2017 (d)	2016	% change 2017 - 2016	2015	% change 2016 - 2015
OPERATIONAL DATA					
Sales volume detail (MMcfe):					
Marcellus (a)	770,620	660,146	16.7	505,102	30.7
Ohio Utica	24,266	536	4,427.2	758	(29.3)
Other	92,634	98,285	(5.7)	97,222	1.1
Total production sales volumes (b)	887,520	758,967	16.9	603,082	25.8
Average daily sales volumes (MMcfe/d)	2,432	2,074	17.3	1,652	25.5
Average realized price ($/Mcfe)	$3.04	$2.47	23.1	$3.09	(20.1)
Gathering to EQM Gathering and RMP Gathering ($/Mcfe)	$0.47	$0.48	(2.1)	$0.51	(5.9)
Transmission to EQM Transmission ($/Mcfe)	$0.20	$0.20	—	$0.20	—
Third-party gathering and transmission ($/Mcfe)	$0.42	$0.32	31.3	$0.29	10.3
Processing ($/Mcfe)	$0.20	$0.16	25.0	$0.17	(5.9)
Lease operating expenses (LOE), excluding production taxes ($/Mcfe)	$0.13	$0.15	(13.3)	$0.19	(21.1)
Production taxes ($/Mcfe)	$0.08	$0.08	—	$0.10	(20.0)
Production depletion ($/Mcfe)	$1.04	$1.06	(1.9)	$1.18	(10.2)
Depreciation, depletion and amortization (DD&A) (thousands):					
Production depletion	$924,430	$803,883	15.0	$713,651	12.6
Other DD&A	57,673	55,135	4.6	51,647	6.8
Total DD&A	$982,103	$859,018	14.3	$765,298	12.2
Capital expenditures (thousands) (c)	$2,430,094	$2,073,907	17.2	$1,893,750	9.5
FINANCIAL DATA (thousands)					
Revenues:					
Sales of natural gas, oil and NGLs	$2,651,318	$1,594,997	66.2	$1,690,360	(5.6)
Pipeline and net marketing services	64,998	41,048	58.3	55,542	(26.1)
Gain (loss) on derivatives not designated as hedges	390,021	(248,991)	(256.6)	385,762	(164.5)
Total operating revenues	3,106,337	1,387,054	124.0	2,131,664	(34.9)
Operating expenses:					
Gathering	480,111	413,758	16.0	330,562	25.2
Transmission	495,635	341,569	45.1	268,368	27.3
Processing	179,538	124,864	43.8	100,329	24.5

LOE, excluding production taxes	113,937	112,509	1.3	116,527	(3.4)
Production taxes	68,848	62,317	10.5	61,408	1.5
Exploration	25,117	13,410	87.3	61,970	(78.4)
Selling, general and administrative (SG&A)	165,792	180,426	(8.1)	172,725	4.5
DD&A	982,103	859,018	14.3	765,298	12.2
Amortization of intangible assets	5,540	—	100.0	—	—
Impairment of long-lived assets	—	6,939	(100.0)	122,469	(94.3)
Total operating expenses	2,516,621	2,114,810	19.0	1,999,656	5.8
Gain on sale / exchange of assets	—	8,025	(100.0)	—	100.0
Operating income (loss)	$589,716	$(719,731)	(181.9)	$132,008	(645.2)

(a) Includes Upper Devonian wells.

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

(c) Includes cash capital expenditures of $819.0 million, non-cash capital expenditures of $10.0 million and measurement period adjustments of $(14.3) million for acquisitions during the year ended December 31, 2017. Includes cash capital expenditures of $1,051.2 million and non-cash capital expenditures of $87.6 million related to acquisitions during the year ended December 31, 2016. See Note 10 to the Consolidated Financial Statements for additional information related to these transactions.

(d) For the year ended December 31, 2017, the operating income for EQT Production includes the results of operations for the production operations and retained midstream operations acquired in the Rice Merger for the period of November 13, 2017 through December 31, 2017. See Note 2 for a discussion of the Rice Merger.

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Year Ended December 31, 2017 vs. December 31, 2016

EQT Production's operating income totaled $589.7 million for 2017 compared to operating loss of $719.7 million for 2016. The $1,309.4 million increase was primarily due to gains on derivatives not designated as hedges for the year ended December 31, 2017 compared to losses on derivatives not designated as hedges for the year ended December 31, 2016, higher average realized price and increased sales volumes of produced natural gas and NGLs, partly offset by increased operating expenses. These variances include the impact of the operations of Rice for the period subsequent to the Rice Merger, which added approximately $165.6 million of operating income for the year ended December 31, 2017, including $114.6 million in gains on derivatives not designated as hedges.

Total operating revenues were $3,106.3 million for 2017 compared to $1,387.1 million for 2016. Sales of natural gas, oil and NGLs increased as a result of a higher average realized price and a 17% increase in production sales volumes in 2017. EQT Production received $40.7 million and $279.4 million of net cash settlements for derivatives not designated as hedges for the years ended December 31, 2017 and 2016, 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 recent acquisition activity, including the Rice Merger, as well as increased production from the 2015 and 2016 drilling programs, primarily in the Marcellus play, partially offset by the normal production decline in the Company's producing wells in 2017.

The $0.57 per Mcfe increase in the average realized price for the year ended December 31, 2017 was primarily due to the increase in the average NYMEX natural gas price net of cash settled derivatives of $0.29 per Mcf, an increase in the average natural gas differential of $0.19 per Mcf and an increase in liquids prices. The improvement in the average differential primarily related to more favorable basis partly offset by unfavorable cash settled basis swaps. During 2017, basis improved in the Appalachian Basin and at sales points reached through the Company's transportation portfolio, particularly in the United States Northeast. In addition, the Company started flowing its 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 for the year ended December 31, 2017 compared to the year ended December 31, 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 $24.0 million increase in these revenues primarily related to increased gathering revenues for services provided to third parties on gathering lines acquired from Rice in addition to costs, net of recoveries, for the Company's Rockies Express Pipeline capacity in 2016.

EQT Production total operating revenues for the year ended December 31, 2017 included a $390.0 million gain on derivatives not designated as hedges compared to a $249.0 million loss on derivatives not designated as hedges for the year ended December 31, 2016. The gains for the year ended December 31, 2017 primarily related to increases in the fair market value of EQT Production's NYMEX swaps due to decreased NYMEX prices, partly offset by decreases in the fair market value of its basis swaps due to increased basis prices.

Gathering expense increased due to increased affiliate and third party gathering capacity. The Rice Merger increased affiliate gathering expense as a result of volumes gathered by RMP Gathering which added approximately $21.0 million of expense for the post-Rice Merger period. In addition, EQT Production increased firm gathering capacity on the affiliate gathering systems owned by EQM Gathering in the fourth quarter of 2016 and 2017. The Company's 2016 and 2017 acquisitions, excluding Rice, added third party gathering capacity and expense. Transmission expense increased due to increased third party capacity and increased firm contracts with affiliates incurred to move EQT Production's natural gas out of the Appalachian Basin. During the fourth quarter of 2016, EQM's Ohio Valley

Connector (OVC) was placed into service and as a result, the Company started flowing its produced volumes to its Rockies Express pipeline capacity. Additionally, the Company's firm capacity on Rockies Express pipeline increased in the first quarter of 2017. Firm capacity acquired in connection with the Rice Merger also increased transmission expenses by approximately $24.2 million. In the fourth quarter of 2016, the Company started flowing its produced volumes to its Texas Eastern Transmission Gulf Markets pipeline capacity. Processing expense increased 44% as a result of increased processing capacity acquired through recent acquisitions and higher volumes processed, which is consistent with higher ethane and NGLs sales volumes of approximately 50% during 2017.

The increase in LOE was primarily due to higher salt water disposal costs. Production taxes increased as a result of higher market prices during the year ended December 31, 2017 in combination with an increase in the number of wells drilled in Pennsylvania and an increase in production volumes from recent acquisitions.

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Exploration expense increased primarily due to expenses related to an exploratory well in a non-core operating area classified as a dry hole in 2017.

SG&A expense decreased primarily due to lower pension expense of $9.4 million related to the termination of the EQT Corporation Retirement Plan for Employees in the second quarter of 2016, lower legal reserves in 2017, a reduction to the reserve for uncollectible accounts, and the absence of costs related to the consolidation of the Company's Huron operations in 2016. This was partly offset by higher costs associated with recent acquisitions.

DD&A expense increased on higher production depletion as a result of higher produced volumes partly offset by a lower overall depletion rate in 2017. Amortization of intangible assets increased as a result of intangible assets acquired in connection with the Rice Merger in 2017.

Impairment of long-lived assets decreased $6.9 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. 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 Company did not identify any such leases in 2017.

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, 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. 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 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 an $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.

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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 due to increased affiliate firm capacity and volumetric charges and due to increased third party volumetric charges. Transmission expense increased as a result of higher third party costs incurred to move EQT Production’s natural gas out of the Appalachian Basin and increased affiliate firm capacity charges. Processing expenses increased due to higher production volumes.

The decrease in LOE was primarily due to lower 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 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 was lower primarily due to a 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 due to higher litigation costs, a $9.4 million charge related to the termination of the EQT Corporation Retirement Plan for Employees incurred in 2016, an increase to the reserve for uncollectible accounts, and 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 drilling program reduction charges in the Permian and Huron Basins in 2015, decreased personnel costs, decreased professional service costs and 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 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 and impairments of proved properties in the Utica Shale of Ohio, as well as unproved property impairments and 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.

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EQM Gathering

Results of Operations

	Years Ended December 31,				
	2017	2016	% change 2017 - 2016	2015	% change 2016 - 2015
FINANCIAL DATA		(Thousands, other than per day amounts)			
Firm reservation fee revenues	$407,355	$339,237	20.1	$267,517	26.8
Volumetric based fee revenues:					
Usage fees under firm contracts (a)	32,206	38,408	(16.1)	33,021	16.3
Usage fees under interruptible contracts	14,975	19,849	(24.6)	34,567	(42.6)
Total volumetric based fee revenues	47,181	58,257	(19.0)	67,588	(13.8)
Total operating revenues	454,536	397,494	14.4	335,105	18.6
Operating expenses:					
Operating and maintenance	43,235	38,367	12.7	37,011	3.7
Selling, general and administrative	38,942	39,678	(1.9)	30,477	30.2
Depreciation and amortization	38,796	30,422	27.5	24,360	24.9
Total operating expenses	120,973	108,467	11.5	91,848	18.1
Operating income	$333,563	$289,027	15.4	$243,257	18.8
OPERATIONAL DATA					
Gathered volumes (BBtu per day):					
Firm capacity reservation	1,826	1,553	17.6	1,140	36.2
Volumetric based services (b)	361	420	(14.0)	485	(13.4)
Total gathered volumes	2,187	1,973	10.8	1,625	21.4
Capital expenditures	$196,871	$295,315	(33.3)	$225,537	30.9

(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, 2017 vs. December 31, 2016

Gathering revenues increased by $57.0 million driven by third party and affiliate production development in the Marcellus Shale. EQM Gathering increased firm reservation fee revenues in 2017 compared to 2016 as a result of third parties and affiliates contracting for additional firm gathering capacity, which increased firm gathering capacity by approximately 475 MMcf per day following the completion of the Range Resources header pipeline project and various affiliate wellhead gathering expansion projects. The decrease in usage fees under firm contracts was due to lower affiliate volumes in excess of firm contracted capacity. The decrease in usage fees under interruptible contracts was primarily due to the additional contracts for firm capacity.

Operating expenses increased by $12.5 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. Operating and maintenance expense increased primarily as a result of higher personnel costs and increased property taxes. Selling, general and administrative expenses decreased primarily due to lower corporate allocations from the Company as a result of the Company’s shift in focus during 2017 from midstream drop-down transactions to upstream asset and corporate acquisition projects partly offset by increased miscellaneous administrative costs. Depreciation and amortization expense increased $8.4 million due to additional assets placed in-service including those associated with the Range Resources header pipeline project and various affiliate wellhead gathering expansion projects.

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. EQM 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 Northern West Virginia gathering system (NWV Gathering) and Jupiter gathering system (Jupiter) expansion projects in the

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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.

EQM Transmission

Results of Operations

	Years Ended December 31,				
	2017	2016	% change 2017 - 2016	2015	% change 2016 - 2015
FINANCIAL DATA		(Thousands, other than per day amounts)			
Firm reservation revenues	$348,193	$277,816	25.3	$247,231	12.4
Volumetric based fee revenues:					
Usage fees under firm contracts[(a)]	13,743	45,679	(69.9)	42,646	7.1
Usage fees under interruptible contracts	17,624	14,625	20.5	7,954	83.9
Total volumetric based fee revenues	31,367	60,304	(48.0)	50,600	19.2
Total operating revenues	379,560	338,120	12.3	297,831	13.5
Operating expenses:					
Operating and maintenance	41,482	34,846	19.0	33,092	5.3
Selling, general and administrative	32,244	33,083	(2.5)	31,425	5.3
Depreciation and amortization	58,689	32,269	81.9	25,535	26.4
Total operating expenses	132,415	100,198	32.2	90,052	11.3
Operating income	$247,145	$237,922	3.9	$207,779	14.5
OPERATIONAL DATA					
Transmission pipeline throughput (BBtu per day)					
Firm capacity reservation	2,399	1,651	45.3	1,841	(10.3)
Volumetric based services[(b)]	37	430	(91.4)	281	53.0
Total transmission pipeline throughput	2,436	2,081	17.1	2,122	(1.9)
Average contracted firm transmission reservation commitments (BBtu per day)	3,627	2,814	28.9	2,624	7.2
Capital expenditures	$111,102	$292,049	(62.0)	$203,706	43.4

(a) Includes commodity charges and fees on all volumes transported under firm contracts as well as transmission fees on volumes 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, 2017 vs. December 31, 2016

Total operating revenues increased by $41.4 million. Firm reservation fee revenues increased due to affiliates and third parties contracting for additional firm capacity, primarily on the OVC, as well as higher contractual rates on existing contracts in the current year. The firm capacity on the OVC resulted in lower affiliate usage fees under firm contracts. The increase in usage fees under interruptible contracts includes increased storage and parking revenue, which does not have pipeline throughput associated with it, partly offset by reduced throughput on interruptible contracts.

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Operating expenses increased by $32.2 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. Operating and maintenance expense increased primarily due to property taxes on the OVC and higher personnel costs. Selling, general and administrative expenses decreased primarily due to lower corporate allocations from the Company as a result of the Company's shift in focus during 2017 from midstream drop-down transactions to upstream asset and corporate acquisition projects. The increase in depreciation and amortization expense was the result of the OVC project placed in-service in the fourth quarter of 2016 and a non-cash charge to depreciation and amortization expense of $10.5 million related to the revaluation of differences between the regulatory and tax bases in EQM's regulated property, plant and equipment. The related regulatory liability will be amortized over the estimated useful life of the underlying property which is 43 years.

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

Total operating 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 2016. 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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RMP Gathering

Results of Operations

	Years Ended December 31,				
	2017 (a)	2016	% change 2017 - 2016	2015	% change 2016 - 2015
FINANCIAL DATA	(Thousands, other than per day amounts)				
Gathering revenues:					
Affiliate	$ 26,242	$ —	100.0	$ —	—
Third-party	19	—	100.0	—	—
Total gathering revenues	26,261	—	100.0	—	—
Compression revenues:					
Affiliate	4,343	—	100.0	—	—
Third-party	10	—	100.0	—	—
Total compression revenues	4,353	—	100.0	—	—
Total operating revenues	30,614	—	100.0	—	—
Operating expenses:					
Operation and maintenance expense	1,584	—	100.0	—	—
General and administrative expense	3,265	—	100.0	—	—
Depreciation expense	3,965	—	100.0	—	—
Total operating expenses	8,814	—	100.0	—	—
Operating income (loss)	$ 21,800	$ —	100.0	$ —	—
OPERATIONAL DATA					
Gathered volumes (BBtu/d):	1,547	—	100.0	—	—
Compression volumes (BBtu/d):	1,155	—	100.0	—	—
Capital expenditures	$ 28,320	$ —	100.0	$ —	—

(a) This table sets forth selected financial and operational data for RMP Gathering for the period November 13, 2017 through December 31, 2017, as the Company acquired RMP Gathering on November 13, 2017 as part of the Rice Merger.

The majority of RMP Gathering revenues are from contracts with EQT Production to gather gas in Washington and Greene Counties, Pennsylvania. RMP Gathering provides all services under long-term contracts that are supported in most cases by acreage dedications. RMP Gathering charges separate rates for gathering and compression services based on the actual volumes gathered and compressed. During the period from November 13, 2017 through December 31, 2017, operating expenses are composed of customary expenses for a gathering business.

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RMP Water

Results of Operations

	Years Ended December 31,				
	2017 (a)	2016	% change 2017 - 2016	2015	% change 2016 - 2015
FINANCIAL DATA	(Thousands, other than per day amounts)				
Operating revenues:					
Affiliate	$ 13,549	$ —	100.0	$ —	—
Third-party	56	—	100.0	—	—
Total operating revenues	13,605	—	100.0	—	—
Operating expenses:					
Operation and maintenance expense	5,598	—	100.0	—	—
General and administrative expense	347	—	100.0	—	—
Depreciation expense	3,515	—	100.0	—	—
Total operating expenses	9,460	—	100.0	—	—
Operating income (loss)	$ 4,145	$ —	100.0	$ —	—
OPERATIONAL DATA					
Water services volumes (in MMgal):	226	—	100.0	—	—
Capital expenditures	$ 6,233	$ —	100.0	$ —	—

(a) This table sets forth selected financial and operational data for RMP Water for the period November 13, 2017 through December 31, 2017, as the Company acquired RMP Water on November 13, 2017 as part of the Rice Merger.

RMP Water provides fresh water for well completions operations in the Marcellus and Utica Shales and collects and recycles or disposes of flowback and produced water. The majority of RMP Water's services are provided to EQT Production. RMP Water offers its services on a volumetric basis, supported by an acreage dedication from EQT Production for certain drilling areas. RMP Water charges customers a fee per gallon of water; this fee is tiered and thus is lower on a per gallon basis once the customer meets certain volumetric thresholds. During the period from November 13, 2017 through December 31, 2017, operating expenses are composed of customary expenses for a water business.

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Other Income Statement Items

Other Income

	Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Other income	$24,955	$31,693	$9,953

For the years ended December 31, 2017, 2016 and 2015, the Company recorded equity in earnings of nonconsolidated investments of $22.2 million, $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 years ended December 31, 2017, 2016 and 2015, the Company recorded AFUDC of $5.1 million, $19.4 million and $6.3 million, respectively. The changes in AFUDC were mainly attributable to the timing of spending on the OVC project.

The Company initiated its investments in trading securities in 2016 to enhance returns on a portion of its significant cash balance at that time.Trading securities consist of liquid debt securities that are carried at fair value. For the years ended December 31, 2017 and 2016 the Company recorded realized losses of $2.6 million and unrealized gains of $1.5 million, respectively, on these debt securities. As of March 31, 2017, the Company closed its positions on all trading securities.

Loss on Debt Extinguishment

	Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Loss on debt extinguishment	$ 12,641	$ —	$ —

For the year ended December 31, 2017, the Company recorded loss on debt extinguishment of $12.6 million in connection with the early extinguishment on November 3, 2017 of the $200 million aggregate principal amount 5.15% Senior Notes due 2018 and $500 million aggregate principal amount 6.50% Senior Notes due 2018. The loss consists of $12.2 million paid in excess of par in order to extinguish the debt prior to maturity and $0.4 million in non-cash expenses related to the write-off of unamortized financing costs and discounts.

Interest Expense

	Years Ended December 31,		
	2017	2016	2015
		(Thousands)	
Interest expense	$202,772	$ 147,920	$146,531

Interest expense increased $54.9 million in 2017 compared to 2016 primarily driven by $23.6 million of interest incurred on Senior Notes issued in October 2017, $17.4 million of interest incurred on EQM's Senior Notes issued in November 2016, $8.0 million of expense related to the bridge financing commitment for the Rice Merger and $6.0 million of interest incurred on credit facility borrowings partly offset by a $7.0 million decrease due to the early extinguishment of EQT Senior Notes.

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.

The weighted average annual interest rates on the weighted average principal outstanding of the Company's Senior Notes, excluding EQM's Senior Notes, were 5.6%, 6.5%, and 6.5% for 2017, 2016 and 2015, respectively. The weighted average annual interest rates on EQM's Senior Notes were 4.1% for 2017 and 4.0% for each of 2016 and 2015.

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See Note 14 to the Consolidated Financial Statements for discussion of the borrowings and weighted average interest rates for EQT's, EQM's and RMP's credit facilities.

Income Taxes

	Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Income tax (benefit) expense	$(1,115,619)	$(263,464)	$104,675

On December 22, 2017, the U.S. Congress enacted the law known as the Tax Cuts and Jobs Act of 2017 (the Tax Reform Legislation), which made significant changes to U.S. federal income tax law, including lowering the federal corporate tax rate to 21% from 35% beginning January 1, 2018. As a result of the change in the corporate tax rate, the Company recorded a deferred tax benefit of $1.2 billion during the year ended December 31, 2017 to revalue its existing net deferred tax liabilities to the lower rate.

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, have historically been limited for purposes of the alternative minimum tax (AMT) and this has resulted in the Company paying AMT even when generating or utilizing a net operating loss carryforward (NOL) to offset regular taxable income.

The Tax Reform Legislation also repealed the AMT for tax years beginning January 1, 2018 and provides that existing AMT credit carryforwards can be utilized to offset current federal tax liability in tax years 2018 through 2020. In addition, 50% of any unused AMT credit carryforwards can be refunded during these years with any remaining AMT credit carryforward being fully refunded in 2021. The Company had approximately $435 million of AMT credit carryforward as of December 31, 2017. In addition, the Tax Reform Legislation preserved deductibility of IDCs, and provides for 100% bonus depreciation on some tangible property expenditures through 2022.

The Tax Reform Legislation contains several other provisions, such as limiting the utilization of NOLs generated after December 31, 2017 that are carried into future years to 80% of taxable income and limitations on the deductibility of interest expense, which are not expected to have a material effect on the Company's results of operations. As of December 31, 2017, the Company has not completed its accounting for the effects of the Tax Reform Legislation, but has recorded provisional amounts for the revaluing of net deferred tax liabilities as well as the state income tax effects related to the Tax Reform Legislation. The Company also considered whether existing deferred tax amounts will be recovered in future periods under this legislation. However, the Company is still analyzing certain aspects of the Tax Reform Legislation and refining calculations, which could potentially impact the measurement of these balances or potentially give rise to new deferred tax amounts. The Company will refine its estimates to incorporate new or better information as it comes available through the filing date of its 2017 U.S. income tax returns in the fourth quarter of 2018.

All of EQGP's, RMP's and Strike Force Midstream'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 and RMP's income allocated to the noncontrolling public limited partners of EQGP, EQM, and RMP or to the minority owner of Strike Force Midstream, 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 2017 and 2016, the Company generated a federal taxable loss and the Company paid AMT in 2016. The federal and AMT NOLs generated by the taxable losses for 2017 and 2016 will be carried back to 2015 and 2014 to generate a tax refund from 2015 and an increase in AMT credit carryforwards for those years. The Company paid federal income tax in 2015 as a result of tax gains related to EQGP's IPO and the sale of NWV Gathering to EQM during that year.

See Note 11 to the Consolidated Financial Statements for further discussion of the Company’s income tax (benefit) expense, including a reconciliation between income tax expense calculated at the current federal statutory rate and the effective tax rate reflected in the Company's financial statements for each of the years ended December 31, 2017, 2016 and 2015.

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Net Income Attributable to Noncontrolling Interests

	Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Net income attributable to noncontrolling interests	$349,613	$321,920	$236,715

The increase in net income attributable to noncontrolling interests for the year ended December 31, 2017 was the result of higher net income at EQM and noncontrolling interests in RMP and Strike Force Midstream as a result of the Rice Merger. The increase in net income attributable to noncontrolling interests for the year ended December 31, 2016 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's board of directors has formed a committee to evaluate options for addressing the Company's sum-of-the-parts discount. The board will announce a decision by the end of March, 2018, after considering the committee's recommendation.

The Company is committed to profitably and safely developing its Appalachian Basin natural gas and NGL reserves through environmentally responsible, cost-effective and technologically advanced horizontal drilling. The Company believes the long-term outlook for its business is favorable due to the Company's substantial resource base, low cost structure, financial strength, risk management, including its 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 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 the highest value development opportunities. Upon the closing of the Rice Merger, the Company's consolidation goals were largely met and the Company plans to focus on integrating the Rice assets and realizing higher returns through longer laterals and achieving an even lower operating cost structure. The Company will also continue to pursue tactical acquisitions of fill-in acreage to extend laterals and has announced its intention to sell the Rice retained midstream assets to EQM through one or more drop-down transactions.

EQT Production expects to spend approximately $2.2 billion for well development (primarily drilling and completion) in 2018, which is expected to support the drilling of approximately 195 gross wells, including 134 Marcellus wells, 16 Upper Devonian wells and 45 Ohio Utica wells. The Company also intends to spend approximately $0.2 billion for acreage fill-ins, bolt-on leasing and other items. Estimated sales volumes are expected to be 1,520 - 1,560 Bcfe for 2018.

The 2018 drilling program is expected to support a 15% increase in production sales volume in 2019 over our 2018 expected sales volumes with total NGLs volumes expected to be 12,300 - 12,600 Mbbls. To support continued growth in production, the Company plans to invest approximately $1.5 billion on midstream infrastructure through EQM in 2018, including capital contributions to the MVP Joint Venture of $1.1 billion. RMP investments in organic projects are expected to total approximately $260 million in 2018, including $215 million for gathering and compression and $45 million for water infrastructure.

The 2018 capital investment plan for EQT Production is expected to be funded by cash generated from operations and cash on hand. EQM's available sources of liquidity include cash on hand and generated from operations, borrowings under its credit facilities, debt offerings and issuances of additional EQM partnership interests. RMP's 2018 capital investment plan is expected to be funded by cash generated from operations and borrowings under its credit facility.

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. 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 and other market point basis, and NGLs and thus cannot predict the ultimate impact of prices on its operations.

The Company's 2018 capital expenditure forecast for well development is 59% higher than its 2017 well development spending. 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. Lower prices could also result in non-cash impairments in the book value of the Company’s oil and gas

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properties, goodwill or other long lived intangible assets or downward adjustments to the Company's estimated proved reserves. Any such impairment and/or downward adjustment to the Company's estimated reserves could potentially be material to the Company.

Impairment of Oil and Gas Properties and Goodwill

See "Critical Accounting Policies and Estimates" 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 in those years. No indicators of impairment were identified as of December 31, 2017. Although the Company did not have indicators of impairment or record an impairment on its oil and gas producing properties during 2017, 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, 2017.

See "Critical Accounting Policies and Estimates" for a discussion of the Company's accounting policies and significant assumptions related to evaluating the Company's goodwill for impairment. The Company evaluated goodwill for impairment at December 31, 2017 and determined there was no indicator of impairment. We use a combination of the income and market approach to estimate the fair value of a reporting unit. The fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management's estimates of future financial results as well as other assumptions such as movement in the Company's stock price, weighted-average cost of capital, terminal growth rates and industry multiples. Although we believe the estimates and assumptions used in estimating the fair value are reasonable and appropriate, different estimates and assumptions could materially impact the calculated fair value of the reporting units. Additionally, future results could differ from our current estimates and assumptions. Any potential change in such estimates and assumptions would have an impact on the results of operations and financial position. Due to the uncertainty inherent in, and the interdependence of, the assumptions of underlying assets and goodwill impairment determinations, the Company cannot predict if future impairment charges will be recognized and, if so, an estimate of the impairment charges that would be recorded in any future period.

See "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, adverse changes in well performance or impairment of goodwill and other long lived intangible assets 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, 2017 were proceeds from the 2017 Notes Offering (defined in Note 15 to the Consolidated Financial Statements), borrowings on credit facilities and cash flows from operating activities, while the primary uses of cash were for redemptions and repayments of Rice's Senior Notes and credit facilities in connection with the closing of the Rice Merger, capital expenditures, the cash portion of the Merger Consideration for the Rice Merger, and redemptions of Company Senior Notes.

Operating Activities

The Company's net cash provided by operating activities increased $573.4 million from full year 2016 to full year 2017. The increase in cash flows provided by operating activities was primarily driven by higher operating income for which contributing factors are discussed in the "Consolidated Results of Operations" and "Business Segment Results of Operations" sections herein and the timing of payments between the two periods, partly offset by lower cash settlements received on derivatives not designated as hedges.

The Company’s net cash provided by operating activities decreased by $152.6 million from full year 2015 to full year 2016. The decrease in cash flows provided by operating activities was 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 outside of the current market view as reflected in forward strip pricing. Refer to "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.

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Investing Activities

Cash flows used in investing activities totaled $4,127.1 million for 2017 as compared to $2,961.5 million for 2016. The $1,165.6 million increase was primarily due to investment in the Rice Merger, an increase in capital expenditures for drilling and completions spending, and higher capital contributions to the MVP Joint Venture, partly offset by a decrease in capital expenditures for other property acquisitions, cash received from the sale of trading securities and lower EQM capital expenditures.

On November 13, 2017, in conjunction with the Rice Merger, each share of the common stock, par value $0.01 per share, of Rice (the Rice Common Stock) issued and outstanding immediately prior to the Effective Time was converted into the right to receive 0.37 (the Exchange Ratio) of a share of the common stock, no par value, of the Company (Company Common Stock) and $5.30 in cash (collectively, the Merger Consideration). The aggregate Merger Consideration consisted of approximately 91 million shares of Company Common Stock and approximately $1.6 billion in cash (net of cash acquired and inclusive of amounts payable to employees of Rice who did not continue with the Company following the Effective Time). See Note 2 to the Consolidated Financial Statements for further discussion of the Rice Merger.

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.

Capital Expenditures
(in millions)

	2017 Actual	2016 Actual	2015 Actual
Well development (primarily drilling and completion)	1,385	783	1,670
Property acquisitions	1,007	1,284	182
Other Production infrastructure	38	7	41
EQM Gathering	197	295	226
EQM Transmission	111	292	204
RMP Gathering	28	—	—
RMP Water	6	—	—
Other corporate items	7	7	21
Total	$2,779	$2,668	$2,344
Less: non-cash *	9	77	(90)
Total cash capital expenditures	$2,770	$2,591	$2,434

* 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, 2017 included $10.0 million of non-cash capital expenditures related to 2017 acquisitions and $(14.3) million of measurement period adjustments for 2016 acquisitions. The year ended December 31, 2016 included $87.6 million of non-cash capital expenditures related to 2016 acquisitions.

The Company has forecast a 2018 capital expenditure spending plan of approximately $2.4 billion for EQT Production, which includes $2.2 billion for well development (primarily drilling and completion) and $0.2 billion for acreage fill-ins, bolt-on leasing and other items. The Company has also forecast an EQM 2018 capital expenditure spending plan of approximately $1.5 billion on midstream infrastructure including capital contributions to MVP and an RMP 2018 capital expenditure spending plan of approximately $260 million for gathering infrastructure and water infrastructure.

Capital expenditures for drilling and development totaled $1,385 million and $783 million during 2017 and 2016, respectively. The Company spud 201 gross wells in 2017, including 144 horizontal Marcellus wells, 49 horizontal Upper Devonian wells, seven horizontal Ohio Utica wells and one other well. The Company spud 135 gross wells in 2016, including 117 horizontal Marcellus wells, 13 horizontal Upper Devonian wells and 4 horizontal Utica wells. The increase in capital expenditures for well development in 2017 was driven primarily by the timing of drilling and completions activities between years and an increase in wells spud. Capital expenditures for 2017 also included $1,007 million for property acquisitions, compared to $1,284 million of capital expenditures in 2016 for property acquisitions. These acquisitions are discussed in Note 10 to the Consolidated Financial Statements.

Capital expenditures for drilling and development totaled $783 million and $1,670 million during 2016 and 2015, respectively. 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 10 to the Consolidated Financial Statements.

Capital expenditures for the EQM gathering and transmission operations totaled $308 million for 2017 and $587 million for 2016, 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 decrease 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, primarily related to expansion capital expenditures.

Financing Activities

Cash flows provided by financing activities totaled $1,533.1 million for 2017 as compared to $1,399.5 million for 2016. During 2017, the Company's primary sources of financing cash flows were net proceeds from the 2017 Notes Offering (defined in Note 15 to the Consolidated Financial Statements) and borrowings on credit facilities. The primary financing uses of cash during 2017 were redemptions and repayment of Rice's Senior Notes and credit facilities in connection with the closing of the Rice Merger, redemption of the Company's Senior Notes and distributions to noncontrolling interests.

On January 17, 2018, the Board of Directors of the Company declared a regular quarterly cash dividend of three cents per share, payable March 1, 2018, to the Company’s shareholders of record at the close of business on February 14, 2018.

On January 18, 2018, the Board of Directors of EQGP's general partner declared a cash distribution to EQGP's unitholders for the fourth quarter of 2017 of $0.244 per common unit, or approximately $64.9 million. The cash distribution will be paid on February 23, 2018 to unitholders of record, including the Company, at the close of business on February 2, 2018.

On January 18, 2018, the Board of Directors of EQM’s general partner declared a cash distribution to EQM’s unitholders for the fourth quarter of 2017 of $1.025 per common unit. The cash distribution was paid on February 14, 2018 to unitholders of record, including EQGP, at the close of business on February 2, 2018. Cash distributions by EQM to EQGP were approximately $65.7 million consisting of: $22.4 million in respect of its limited partner interest, $2.2 million in respect of its general partner interest and $41.1 million in respect of its IDRs in EQM.

On January 18, 2018, the Board of Directors of RMP’s general partner declared a cash distribution to RMP’s unitholders for the fourth quarter of 2017 of $0.2917 per common and subordinated unit. The cash distribution was paid on February 14, 2018 to unitholders of record, including Rice Midstream GP Holdings, LP (RMGP), which is an indirect wholly owned subsidiary of EQT, at the close of business on February 2, 2018. Cash distributions by RMP to RMGP were approximately $11.4 million, consisting of $8.4 million in respect of its limited partner interest and $3 million in respect of its IDRs in RMP.

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 EQM’s $750 million at-the-market (ATM) common unit offering program (the EQM $750 Million ATM Program), as well as proceeds received from the issuance of EQM Senior Notes. 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. In 2015, the Company’s primary sources of financing cash flows were the issuance of EQM and EQGP common units and net borrowings on EQM’s credit facility while the primary uses of financing cash flows were repayments of Senior Notes and distributions to noncontrolling interests.

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.

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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. During the year ended December 31, 2017, the Company also borrowed under the Company's $2.5 billion revolving credit facility to fund a portion of the cash Merger Consideration and pay expenses related to the Rice Merger. In addition, upon the closing of the Rice Merger on November 13, 2017, certain existing letters of credit issued for the account of Rice and its subsidiaries were transferred to the Company's $2.5 billion credit facility.

See Note 14 to the Consolidated Financial Statements for further discussion of EQT's, EQM's and RMP's credit facilities. See also the discussion of the revolving loan agreement between EQT and EQM in Note 4 to the Consolidated Financial Statements.

Security Ratings and Financing Triggers

The table below reflects the credit ratings for debt instruments of the Company at December 31, 2017. 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	Negative
Fitch Ratings Service (Fitch)	BBB-	Stable

The table below reflects the credit ratings for debt instruments of EQM at December 31, 2017. 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

RMP has no long-term debt and is not currently rated by Moody's, S&P, or Fitch.

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

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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, 2017, 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 most significant 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 $1 billion 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, 2017, EQM was in compliance with all debt provisions and covenants.

The RMP credit facility contains various provisions that, if not complied with, could result in termination of the agreement, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the RMP credit facility relate to maintenance of certain financial ratios, as described below, limitations on certain investments and acquisitions, limitations on transactions with affiliates, limitations on restricted payments, limitations on the incurrence of additional indebtedness, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of and certain other defaults under other financial obligations and change of control provisions. The RMP credit facility requires RMP to maintain the following financial ratios:

•an interest coverage ratio of at least 2.50 to 1.0;

•a consolidated total leverage ratio of not more than 4.75 to 1.0, and after electing to issue senior unsecured notes, a consolidated total leverage ratio of not more than 5.25 to 1.0 (with certain increases for measurement periods following the completion of certain acquisitions); and

•if RMP elects to issue senior unsecured notes, a consolidated senior secured leverage ratio of not more than 3.50 to 1.0.

As of December 31, 2017, RMP and RMP OpCo were in compliance with all credit facility provisions and covenants.

EQM ATM Program

During 2015, EQM entered into an equity distribution agreement that established the EQM $750 million ATM Program. EQM had approximately $443 million in remaining capacity under the program as of February 15, 2018.

RMP ATM Program

During 2016, RMP entered into an equity distribution agreement that established the RMP $100 million ATM equity distribution program. RMP had approximately $83.7 million in remaining capacity under the program as of February 15, 2018.

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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, collars and options.

As of January 31, 2018, the approximate volumes and prices of the Company's derivative commodity instruments hedging sales of produced gas for 2018 through 2020 were:

	2018 (a)(b)(c)	2019 (b)	2020
NYMEX Swaps			
Total Volume (Bcf)	541	234	234
Average Price per Mcf (NYMEX) (d)	$ 3.14	$3.03	$3.05
Collars			
Total Volume (Bcf)	117	66	—
Average Floor Price per Mcf (NYMEX) (d)	$ 3.28	$3.15	$—
Average Cap Price per Mcf (NYMEX) (d)	$ 3.78	$3.68	$—
Puts (Long)			
Total Volume (Bcf)	10	7	—
Average Floor Price per Mcf (NYMEX)*	$ 2.91	$2.94	$—

(a) Full year 2018

(b) The Company also sold calendar year 2018 and 2019 calls for approximately 64 Bcf and 45 Bcf, respectively, at strike prices of $3.49 per Mcf and $3.69 per Mcf, respectively.

(c) For 2018, the Company also sold puts for approximately 3 Bcf at a strike price of $2.63 per Mcf.

(d) 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 2018 and 2019 of 121 Bcf and 37 Bcf, respectively, at average NYMEX prices of $2.93 per Mcf and $3.04 per Mcf, respectively. For 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, 2019 and 2020, the Company has a natural gas sales agreement for approximately 49 Bcf per year that includes a NYMEX ceiling price of $3.36 per Mcf. For 2018, 2019 and 2020, the Company also 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 NYMEX 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 7 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 $95 million as of December 31, 2017, extending at a decreasing amount for approximately 11 years.

As of December 31, 2017, 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.

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The NORESCO guarantees and the MVP 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. See "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." in Item 1A, "Risk Factors" for potential risks related to the regulation of rates by the FERC.

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Schedule of Contractual Obligations

The table below presents the Company’s long-term contractual obligations as of December 31, 2017 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 $5.6 billion as of December 31, 2017. These capacity commitments have terms extending up to 20 years. Purchase obligations also exclude future capital contributions to the MVP Joint Venture and purchase obligations of the MVP Joint Venture.

	Total	2018	2019-2020	2021-2022	2023+
	(Thousands)				
Purchase obligations (a)	$16,616,818	$824,813	$2,045,143	$2,004,729	$11,742,133
Senior Notes	5,618,200	8,000	1,711,200	1,524,000	2,375,000
Interest payments on Senior Notes (b)	1,515,749	241,748	449,128	333,269	491,604
Credit facility borrowings (c)	1,761,000	—	286,000	1,475,000	—
Operating leases (d)	231,515	70,887	64,779	27,185	68,664
Water infrastructure (e)	19,547	—	—	—	19,547
Other liabilities (f)	78,748	30,949	47,799	—	—
Total contractual obligations	$25,841,577	$1,176,397	$4,604,049	$5,364,183	$14,696,948

(a) 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 20 years or longer. 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.

(b) Interest payments exclude interest related to the credit facility borrowings and the Floating Rate Notes (defined in Note 15 to the Consolidated Financial Statements) as the interest rates on the Company's, EQM's and RMP's credit facilities and the Floating Rate Notes are variable.

(c) Credit facility borrowings were classified based on the termination dates of the Company's, EQM's and RMP's credit facilities.

(d) 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 $139.2 million as of December 31, 2017. 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 $92.3 million as of December 31, 2017. As of December 31, 2017, the Company had eight horizontal drilling rigs under contract, and an additional horizontal rig will become active on April 1, 2018. All of these will expire in 2019 with dates in this order: June 30, July 31, August 31 (2), September 30, October 31, November 30 and December 31 (2). The Company also had seven tophole drilling rigs under contract, six of which expire in 2018 and one that expires in 2019. Of the six tophole rigs that expire in 2018, the dates are in this order: January 3, February 3, February 25, June 2, August 27 and December 22. The expiration date for the tophole rig in 2019 is March 29. These drilling obligations have been included in the table above. The values in the table represent the gross amounts that the Company is committed to pay as operator. However, the Company will record in the Consolidated Financial Statements the Company's proportionate share of the amounts shown based on its working interest.

(e) See Note 20 for additional information.

(f) The other liabilities line represents commitments for total estimated payouts for the 2017 EQT Value Driver Award Program, 2017 Incentive PSU Program, 2017 restricted stock unit liability awards, 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 11 to the Consolidated Financial Statements, the Company had a total reserve for unrecognized tax benefits at December 31, 2017 of $301.6 million, of which $84.1 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.

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 and Goodwill" 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.

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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.

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 future statutory 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 and Goodwill" 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, other federal tax credit carryforwards, incentive compensation and investment in partnerships. The Company has established a valuation allowance against a portion of the deferred tax assets related to the federal and state NOL carryforwards and alternative minimum tax credit carryforward, as it is believed that it is more likely than not that certain 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 11 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.

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 operates and maintains its gathering systems and transmission and storage system and it intends to do so as long as supply and demand for natural gas exists, which the Company expects for the foreseeable future. The Company is under no legal or contractual obligation to restore or dismantle its gathering systems and transmission and storage system upon abandonment. Therefore, the Company does not have any asset retirement obligations related to its gathering systems and transmission and storage system as of December 31, 2017 and 2016.

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 the 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 the 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.

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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 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.

Business Combinations: Accounting for the acquisition of a business requires the identifiable assets and liabilities acquired to be recorded at fair value.

The most significant assumptions in a business combination include those used to estimate the fair value of the oil and gas properties acquired. The fair value of proved natural gas properties is determined using a risk-adjusted after-tax discounted cash flow analysis based upon significant assumptions including commodity prices; projections of estimated quantities of reserves; projections of future rates of production; timing and amount of future development and operating costs; projected reserve recovery factors; and a weighted average cost of capital.

The Company utilizes the guideline transaction method to estimate the fair value of unproved properties acquired in a business combination which requires the Company to use judgment in considering the value per undeveloped acre in recent comparable transactions to estimate the value of unproved properties.

The estimated fair value of midstream facilities and equipment, generally consisting of pipeline systems and compression stations, is estimated using the cost approach, which incorporates assumptions about the replacement costs for similar assets, the relative age of assets and any potential economic or functional obsolescence.

The fair values of the intangible assets are estimated using the multi-period excess earnings model which estimates revenues and cash flows derived from the intangible asset and then deducts portions of the cash flow that can be attributed to supporting assets otherwise recognized. The Company's intangible assets are comprised of customer relationships and non-compete agreements.

The Rice Merger resulted in share-based compensation modification accounting which is treated as an exchange of the original award for a new award with total compensation cost equal to the grant-date fair value of the original award plus the incremental value of the modification to the award. The calculation of the incremental value is based on the excess of the fair value of the new (modified) award based on current circumstances over the fair value of the original option measured immediately before its terms are modified based on current circumstances.

The Company believes that the accounting estimates related to business combinations are "critical accounting estimates" because the Company must, in determining the fair value of assets acquired, make assumptions about future commodity prices; projections of estimated quantities of reserves; projections of future rates of production; projections regarding the timing and amount of future development and operating costs; and projections of reserve recovery factors, per acre values of undeveloped property, replacement cost of and future cash flows from midstream assets, cash flow from customer relationships and non-compete agreements and the pre and post modification value of stock based awards. Different assumptions may result in materially different values for these assets which would impact the Company's financial position and future results of operations.

Goodwill: Goodwill is the cost of an acquisition less the fair value of the identifiable net assets of the acquired business.

Goodwill is evaluated for impairment at least annually, or whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The Company may first consider qualitative factors to assess whether there are indicators that it is more likely than not that the fair value of a reporting unit may not exceed its carrying amount. To the extent that such indicators exist, a two-step goodwill impairment test is completed. The first step compares the fair value of a reporting unit to its carrying value. If the carrying amount of a reporting unit exceeds its fair value,

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the second step is required which compares the implied fair value of the goodwill of a reporting unit to its carrying value. If the carrying value of the goodwill of a reporting unit exceeds its implied fair value, the difference is recognized as an impairment charge. The Company uses a combination of an income and market approach to estimate the fair value of a reporting unit.

The Company believes that the accounting estimates related to goodwill are “critical accounting estimates” because the fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management’s estimates of future financial results. The fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management’s estimates of future financial results as well as other assumptions such as movement in the Company's stock price, weighted-average cost of capital, terminal growth rates and industry multiples. The Company believes the estimates and assumptions used in estimating the fair value are reasonable and appropriate; however, different assumptions and estimates could materially impact the calculated fair value and the resulting determinations about goodwill impairment which could materially impact the Company’s results of operations and financial position. Additionally, future estimates may differ materially from current estimates and assumptions.

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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 material non-cash impairments to the recorded value of the Company’s property, plant and equipment.

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 7 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, collar agreements and option 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 2,148 Bcf of natural gas and 8,943 Mbbls of NGLs as of December 31, 2017, and 646 Bcf of natural gas and 1,095 Mbbls of NGLs as of December 31, 2016. In connection with the Rice Merger, the Company assumed all outstanding derivative commodity instruments held by Rice, which significantly increased the volume of hedges. 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, 2017 and 2016 levels would have increased the fair value of these natural gas derivative instruments by approximately $386.2 million and $179.0

million, respectively. A hypothetical increase of 10% in the market price of natural gas from the December 31, 2017 and 2016 levels would have decreased the fair value of these natural gas derivative instruments by approximately $384.9 million and $181.8 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, 2017 and December 31, 2016. The price change was then applied to these natural gas derivative commodity instruments recorded on the Company's Consolidated Balance Sheets, resulting in the hypothetical 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 held to hedge the Company's forecasted production associated with the hypothetical changes in commodity prices referenced

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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, EQM and RMP earn on cash, cash equivalents and short-term investments and the interest rates the Company, EQM and RMP pay on borrowings under their respective revolving credit facilities and the Company's floating rate notes. All of the Company’s and EQM’s Senior Notes, other than the floating rate notes, 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 14 and 15 to the Consolidated Financial Statements for further discussion of the Company’s, EQM’s, and RMP's borrowings, as applicable, and Note 8 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 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 63%, or $242.0 million, of the Company’s OTC derivative contracts outstanding at December 31, 2017 had a positive fair value. Approximately 11%, or $33.1 million, of the Company’s OTC derivative contracts outstanding at December 31, 2016 had a positive fair value. The increase in derivative contracts with a positive fair value primarily relates to decreased forward NYMEX prices as well as settlements of contracts during 2017 that had a negative fair value as of December 31, 2016.

As of December 31, 2017, 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 in the Appalachian Basin and in markets available through the Company's current transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States. The Company also contracts with certain processors to market a portion of NGLs on behalf of the Company. 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.

No one lender of the large group of financial institutions in the syndicates for the EQT, EQM or RMP credit facilities holds more than 10% of the respective facility. The large syndicate groups and relatively low percentage of participation by each lender are expected to limit the Company's, EQM's and RMP'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

To the Shareholders and the Board of Directors of EQT Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of EQT Corporation and subsidiaries (the Company) as of December 31, 2017 and 2016, the related statements of consolidated operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedule listed in the Index at Item 15 (a) (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, 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 15, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company’s auditor since 1950.

Pittsburgh, Pennsylvania
February 15, 2018

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Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of EQT Corporation

Opinion on Internal Control over Financial Reporting

We have audited EQT Corporation and subsidiaries' internal control over financial reporting as of December 31, 2017, 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). In our opinion, EQT Corporation and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

As indicated in the accompanying Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Rice Energy Inc., which is included in the 2017 consolidated financial statements of the Company and constituted 45% and 53% of total and net assets, respectively, as of December 31, 2017 and 10% and 24% of operating revenues and income before income taxes, respectively, for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Rice Energy Inc.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of EQT Corporation and subsidiaries as of December 31, 2017 and 2016, 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, 2017 and the related notes and the financial statement schedule listed in the Index at Item 15 (a) of the Company and our report dated February 15, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP
Pittsburgh, Pennsylvania
February 15, 2018

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

	2017	2016	2015
	(Thousands except per share amounts)		
Revenues:			
Sales of natural gas, oil and NGLs	$2,651,318	$1,594,997	$1,690,360
Pipeline, water and net marketing services	336,676	262,342	263,640
Gain (loss) on derivatives not designated as hedges	390,021	(248,991)	385,762
Total operating revenues	3,378,015	1,608,348	2,339,762
Operating expenses:			
Transportation and processing	559,839	365,817	275,348
Operation and maintenance	88,866	73,266	69,760
Production	182,737	174,826	177,935
Exploration	25,117	13,410	61,970
Selling, general and administrative	262,664	272,747	249,925
Depreciation, depletion and amortization	1,077,559	927,920	819,216
Impairment of long-lived assets	—	66,687	122,469
Acquisition costs	237,312	—	—
Amortization of intangible assets	10,940	—	—
Total operating expenses	2,445,034	1,894,673	1,776,623
Gain on sale / exchange of assets	—	8,025	—
Operating income (loss)	932,981	(278,300)	563,139
Other income	24,955	31,693	9,953
Loss on debt extinguishment	12,641	—	—
Interest expense	202,772	147,920	146,531
Income (loss) before income taxes	742,523	(394,527)	426,561
Income tax (benefit) expense	(1,115,619)	(263,464)	104,675
Net income (loss)	1,858,142	(131,063)	321,886
Less: Net income attributable to noncontrolling interests	349,613	321,920	236,715
Net income (loss) attributable to EQT Corporation	$1,508,529	$(452,983)	$85,171
Earnings per share of common stock attributable to EQT Corporation:			
Basic:			
Weighted average common stock outstanding	187,380	166,978	152,398
Net income (loss)	$8.05	$(2.71)	$0.56
Diluted:			
Weighted average common stock outstanding	187,727	166,978	152,939
Net income (loss)	$8.04	$(2.71)	$0.56

See notes to consolidated financial statements.

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

	2017	2016	2015
	(Thousands)		
Net income (loss)	$1,858,142	$(131,063)	$321,886
Other comprehensive loss, net of tax:			
Net change in cash flow hedges:			
Natural gas, net of tax benefit of ($3,191), ($36,296) and ($102,271)	(4,982)	(55,155)	(152,359)
Interest rate, net of tax expense of $105, $104 and $100	144	144	144
Pension and other post-retirement benefits liability adjustment, net of tax expense (benefit) of $193, $6,778 and ($564)	338	10,675	(901)
Other comprehensive loss	(4,500)	(44,336)	(153,116)
Comprehensive income (loss)	1,853,642	(175,399)	168,770
Less: Comprehensive income attributable to noncontrolling interests	349,613	321,920	236,715
Comprehensive income (loss) attributable to EQT Corporation	$1,504,029	$(497,319)	$(67,945)

See notes to consolidated financial statements.

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

	2017	2016	2015
	(Thousands)		
Cash flows from operating activities:			
Net income (loss)	$1,858,142	$(131,063)	$321,886
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income taxes	(1,050,612)	(180,261)	17,876
Depreciation, depletion and amortization	1,077,559	927,920	819,216
Amortization of intangibles	10,940	—	—
Asset and lease impairments and exploratory well costs	20,327	75,434	182,242
Gain on sale / exchange of assets	—	(8,025)	—
Loss on debt extinguishment	12,641	—	—
(Recoveries of) provision for losses on accounts receivable	(979)	3,856	(1,903)
Other income	(24,955)	(31,693)	(9,953)
Stock-based compensation expense	94,592	44,605	58,629
(Gain) loss on derivatives not designated as hedges	(390,021)	248,991	(385,762)
Cash settlements received on derivatives not designated as hedges	40,728	279,425	172,093
Pension settlement charge	—	9,403	—
Changes in other assets and liabilities:			
Excess tax benefits on stock-based compensation	—	(1,148)	(22,945)
Accounts receivable	(8,979)	(165,507)	131,031
Accounts payable	(16,680)	40,548	(37,623)
Other items, net	14,995	(48,165)	(27,847)
Net cash provided by operating activities	1,637,698	1,064,320	1,216,940
Cash flows from investing activities:			
Capital expenditures	(1,939,202)	(1,538,125)	(2,434,018)
Cash payments for Rice Merger (as defined in Note 2), net of cash acquired	(1,560,272)	—	—
Capital expenditures for other acquisitions	(818,957)	(1,051,239)	—
Investments in trading securities	—	(288,772)	—
Sales of investments in trading securities	283,758	3,890	—
Dry hole costs	(11,420)	(1,369)	(17,130)
Capital contributions to Mountain Valley Pipeline, LLC	(159,550)	(98,399)	(84,182)
Sales of interests in Mountain Valley Pipeline, LLC	—	12,533	9,723
Restricted cash, net	75,000	(75,000)	—
Proceeds from sale of assets	3,573	75,000	—
Net cash used in investing activities	(4,127,070)	(2,961,481)	(2,525,607)
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
Proceeds from the sale of common units of EQT GP Holdings, LP, net of issuance costs	—	—	673,964
Proceeds from issuance of debt	3,000,000	500,000	—

Increase in borrowings on credit facilities	2,063,000	740,000	617,000
Repayment of borrowings on credit facilities	(1,076,500)	(1,039,000)	(318,000)
Dividends paid	(20,827)	(20,156)	(18,310)
Distributions to noncontrolling interests	(236,123)	(189,981)	(121,759)
Contribution to Strike Force Midstream by minority owner, net of distribution	6,738	—	—
Repayments and retirements of debt	(2,000,000)	(5,119)	(169,004)
Proceeds and excess tax benefits from awards under employee compensation plans	244	6,165	36,965
Cash paid for taxes related to net settlement of share-based incentive awards	(72,116)	(26,931)	(47,013)
Debt issuance costs and revolving credit facility origination fees	(41,876)	(8,580)	—
Premiums paid on debt extinguishment	(89,363)	—	—
Repurchase of common stock	(30)	(30)	(3,375)
Net cash provided by financing activities	1,533,147	1,399,469	1,832,470
Net change in cash and cash equivalents	(956,225)	(497,692)	523,803
Cash and cash equivalents at beginning of year	1,103,540	1,601,232	1,077,429
Cash and cash equivalents at end of year	$147,315	$1,103,540	$1,601,232
Cash paid (received) during the year for:			
Interest, net of amount capitalized	$189,371	$144,657	$147,550
Income taxes, net	$3,637	$(41,142)	$95,708

See notes to consolidated financial statements. See Note 1 for supplemental cash flow information.

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EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2017	2016
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$147,315	$1,103,540
Trading securities	—	286,396
Accounts receivable (less accumulated provision for doubtful accounts: $8,226 in 2017; $6,923 in 2016)	725,236	341,628
Derivative instruments, at fair value	241,952	33,053
Prepaid expenses and other	48,552	63,602
Total current assets	1,163,055	1,828,219
Property, plant and equipment	30,990,309	18,216,775
Less: accumulated depreciation and depletion	6,105,294	5,054,559
Net property, plant and equipment	24,885,015	13,162,216
Restricted cash	—	75,000
Intangible assets, net	736,360	—
Goodwill	1,998,726	—
Investment in unconsolidated entity	460,546	184,562
Other assets	278,902	222,925
Total assets	$29,522,604	$15,472,922

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EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2017	2016
	(Thousands)	
Liabilities and Shareholders' Equity		
Current liabilities:		
Current portion of Senior Notes	$7,999	$—
Accounts payable	654,624	309,978
Derivative instruments, at fair value	139,089	257,943
Other current liabilities	430,525	236,719
Total current liabilities	1,232,237	804,640
Credit facility borrowings	1,761,000	—
Senior Notes	5,562,555	3,289,459
Deferred income taxes	1,768,900	1,760,004
Other liabilities and credits	783,299	499,572
Total liabilities	11,107,991	6,353,675
Equity:		
Shareholders' equity		
Common stock, no par value, authorized 320,000 shares, shares issued: 267,871 in 2017 and 177,896 in 2016	9,388,903	3,440,185
Treasury stock, shares at cost: 3,551 in 2017 (including 253 held in rabbi trust) and 5,069 in 2016 (including 226 held in rabbi trust)	(63,602)	(91,019)
Retained earnings	3,996,775	2,509,073
Accumulated other comprehensive (loss) income	(2,458)	2,042
Total common shareholders' equity	13,319,618	5,860,281
Noncontrolling interests in consolidated subsidiaries	5,094,995	3,258,966
Total equity	18,414,613	9,119,247
Total liabilities and equity	$29,522,604	$15,472,922

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED EQUITY
YEARS ENDED DECEMBER 31, 2017, 2016 and 2015

	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, 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)
	724	42,782			161	42,943

Stock-based compensation plans, net						
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 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
Comprehensive income (net of tax):						
Net income			1,508,529		349,613	1,858,142
Net change in cash flow hedges:						
Natural gas, net of tax of ($3,191)				(4,982)		(4,982)
Interest rate, net of tax of $105				144		144
Pension and other post-retirement benefits liability adjustment, net of tax of $193				338		338
Dividends ($0.12 per share)			(20,827)			(20,827)
Stock-based compensation plans, net	580	26,436			190	26,626
Distributions to noncontrolling interests ($3.655 and $0.806 per common unit for EQT Midstream Partners, LP and EQT GP Holdings, LP, respectively)					(236,123)	(236,123)
Rice Merger, net of withholdings	90,914	5,949,729			1,715,611	7,665,340
Contribution from noncontrolling interest, net of distribution					6,738	6,738
Repurchase of common stock	(1)	(30)				(30)
Balance, December 31, 2017	264,320	$9,325,301	$3,996,775	$ (2,458)	$ 5,094,995	$18,414,613

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.

EQT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2017

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 Company records noncontrolling interest in its financial statements for any non-wholly owned consolidated subsidiary.

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.

Prior to the Rice Merger (as defined in Note 2), the Company reported its results of operations through three business segments: EQT Production, EQT Gathering and EQT Transmission. 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, 2017. Following the Rice Merger, the Company adjusted its internal reporting structure to incorporate the newly acquired assets. The Company now conducts its business through five business segments: EQT Production, EQM Gathering (formerly known as EQT Gathering), EQM Transmission (formerly known as EQT Transmission), RMP Gathering and RMP Water. The EQT Production segment incorporates the Company’s production activities, including those acquired in the Rice Merger, the Company's marketing operations, and certain gathering operations primarily supporting the Company's production activities. The EQM Gathering segment contains the Company's gathering assets that are owned by EQT Midstream Partners, LP (EQM), and the EQM Transmission segment includes the Company's Federal Energy Regulatory Commission (FERC)-regulated interstate pipeline and storage operations, which are owned by EQM. Therefore, the financial and operational disclosures related to EQM Gathering and EQM 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, 2017. The RMP Gathering segment contains the Company's gathering assets that are owned by Rice Midstream Partners, LP (RMP). The RMP Water segment contains the Company's water pipelines, impoundment facilities, pumping stations, take point facilities and measurement facilities owned by RMP. The financial and operational disclosures related to RMP Gathering and RMP Water will be the same as RMP’s successor disclosures for the period subsequent to the Rice Merger in its Annual Report on Form 10-K for the year ended December 31, 2017.

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.

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.

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. At December 31, 2016, the Company held two certificates of deposit (CDs) in denominations greater than $0.1 million with an 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 losses of $2.6 million and unrealized gains of $1.5 million on these debt securities are included in other income in the Statements of Consolidated Operations for the years ended December 31, 2017 and 2016, respectively. At December 31, 2016, investments in trading securities had a fair value of $286.4 million. The Company initiated its investments in trading securities in 2016 to enhance returns on a portion of its significant cash balance at that time. 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. As of March 31, 2017, the Company closed its positions on all trading securities.

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Accounts Receivable: Accounts receivable primarily relate to the sales of natural gas, oil and NGLs and amounts due from joint interest partners. Natural gas, oil and NGLs sales receivables were $516.7 million and $316.9 million at December 31, 2017 and 2016, respectively. Joint interest receivables were $149.3 million and $1.1 million at December 31, 2017 and 2016, respectively.

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 9) into restricted cash for use 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 was not completed within 180 days, the proceeds would have been distributed to the Company by the intermediary and reclassified as available cash within the Consolidated Balance Sheets. The like-kind exchange was finalized in connection with the February 1, 2017 acquisition of approximately 14,000 net Marcellus acres located in Marion, Monongalia and Wetzel Counties, West Virginia, for $130 million.

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, 2017, 2016 and 2015, the Company recorded no lower of cost or market adjustments related to inventory.

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

	As of December 31,	
	2017	2016
	(Thousands)	
Oil and gas producing properties, successful efforts method	$23,937,154	$13,878,659
Accumulated depreciation and depletion	(5,121,646)	(4,217,154)
Net oil and gas producing properties	18,815,508	9,661,505
Gathering assets	2,765,763	1,330,998
Accumulated depreciation and amortization	(151,595)	(110,473)
Net gathering assets	2,614,168	1,220,525
Transmission assets	1,674,080	1,563,860
Accumulated depreciation and amortization	(248,474)	(205,551)
Net transmission assets	1,425,606	1,358,309
Water service assets	193,825	—
Accumulated depreciation and amortization	(3,363)	—
Net water service assets	190,462	—
Other properties, at cost less accumulated depreciation (a)	1,839,271	921,877
Net property, plant and equipment	$24,885,015	$13,162,216

(a) Other properties includes 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 $114.6 million, $115.4 million and $114.4 million in 2017, 2016 and 2015, respectively, for production related activities. The Company also capitalized $20.5 million, $19.2 million and $35.8 million of interest expense related to Marcellus, Upper Devonian and Utica well development in 2017, 2016 and 2015, 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 $1.04 per Mcfe, $1.06 per Mcfe and $1.18 per Mcfe for the years ended December 31, 2017, 2016 and 2015, respectively.

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

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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.

There were no indicators of impairment identified during 2017. Due to the declines in commodity prices during 2016 and 2015, 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, 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 year ended December 31, 2015, EQT Production recognized pre-tax impairment charges on proved oil and gas properties of $98.6 million, which is 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 2015 impairment on proved properties in the Permian Basin of Texas was due to a decline in commodity prices. The 2015 impairment in the Utica Shale of Ohio was 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 year ended December 31, 2017, EQT Production recorded no unproved property impairment. For the years ended December 31, 2016 and 2015, EQT Production recorded unproved property impairments of $6.9 million and $19.7 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. In addition, unproved lease expirations prior to drilling of $7.6 million, $8.7 million and $37.4 million are included in exploration expense of EQT Production for the years ended December 31, 2017, 2016 and 2015, respectively. Unproved properties had a net book value of $5,016.3 million and $1,698.8 million at December 31, 2017 and 2016, respectively.

During each of the years 2017 and 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, 2017 and 2015, respectively. There were no capitalized exploratory wells costs at December 31, 2017. At December 31, 2016, the Company had $5.1 million of capitalized exploratory well costs.

Gathering and transmission property, plant and equipment is carried at cost. Depreciation is calculated using the straight-line method based on estimated service lives. The Company's 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). Water pipelines, pumping stations and impoundment facilities are carried at cost and depreciated on a straight line basis over a useful life of 10 to 15 years.

Maintenance projects that do not increase the overall life of the related assets are expensed. When 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. No impairment of any long-lived asset other than proved and unproved oil and gas properties was recorded in 2017. During the year ended December 31, 2016, the Company

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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.

Goodwill: Goodwill is the cost of an acquisition less the fair value of the identifiable net assets of the acquired business.

Goodwill is evaluated for impairment at least annually, or whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The Company may first consider qualitative factors to assess whether there are indicators that it is more likely than not that the fair value of a reporting unit may not exceed its carrying amount. To the extent that such indicators exist, a two-step goodwill impairment test is completed. The first step compares the fair value of a reporting unit to its carrying value. If the carrying amount of a reporting unit exceeds its fair value, the second step compares the implied fair value of the goodwill of a reporting unit to its carrying value. If the carrying value of the goodwill of a reporting unit exceeds its implied fair value, the difference is recognized as an impairment charge. The Company uses a combination of the income and market approaches to estimate the fair value of a reporting unit.

The Company evaluated goodwill for impairment at December 31, 2017 and determined there was no indicator of impairment.

Intangible Assets: Intangible assets are recorded under the acquisition method of accounting at their estimated fair values at the acquisition date. Fair value is calculated as the present value of estimated future cash flows using a risk-adjusted discount rate. The Company’s intangible assets are composed of customer relationships and non-compete agreements with former Rice Energy Inc. (Rice) executives. The customer relationships acquired have a useful life of approximately 15 years and the non-competition agreements have a useful life of 3 years. The Company calculates amortization of intangible assets using the straight-line method over the estimated useful life of the intangible assets. Amortization expense recorded in the consolidated statements of operations for the year ended December 31, 2017 was $10.9 million. The estimated annual amortization expense over the next five years is as follows: 2018 $82.9 million, 2019 $82.9 million, 2020 $77.5 million, 2021 $41.5 million and 2022 $41.5 million.

Intangible assets, net as of December 31, 2017 are detailed below.

(in thousands)	December 31, 2017
Customer relationships	$ 623,200
Less: accumulated amortization for customer relationships	(5,540)
Non-compete agreements	124,100
Less: accumulated amortization for non-compete agreements	(5,400)
Intangible assets, net	$ 736,360

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 EQM Transmission include interstate pipeline and storage operations subject to regulation by the FERC. EQM 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.

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

	Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Net revenues	$390,883	$347,320	$309,984
Operating expenses	$151,510	$118,611	$109,954

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

	As of December 31,	
	2017	2016
	(Thousands)	
Property, plant & equipment	$1,787,656	$1,675,433
Accumulated depreciation and amortization	(278,756)	(234,336)
Net property, plant & equipment	$1,508,900	$1,441,097

Regulatory assets associated with deferred taxes of $17.7 million and $20.3 million as of December 31, 2017 and 2016, 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.

Regulatory liabilities associated with deferred taxes of $11.3 million as of December 31, 2017 are included in the Consolidated Balance Sheets and represent excess deferred taxes associated with public utility property as a result of the federal income tax rate reduction from 35% to 21% (as discussed in Note 11). Following the normalization provisions of the Internal Revenue Code (IRC), this regulatory liability is amortized on a straight-line basis over the estimated remaining life of the related assets.

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 president and chief executive officer, 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, collar agreements and option 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.

Effective December 31, 2014, the Company elected to de-designate all derivative commodity instruments that were designated and qualified as cash flow hedges. Any changes in fair value of derivative instruments are recognized net within operating revenues in the Statements of Consolidated Operations. 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 other comprehensive income (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 previously designated as cash flow hedges. Since December 31, 2014, the Company has not designated any new derivative instruments as cash flow hedges.

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 $0.8 million, $2.4 million and $1.6 million for the years ended December 31, 2017, 2016 and 2015, 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 $5.1 million, $19.4 million and $6.3 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Other Current Liabilities: Other current liabilities as of December 31, 2017 and 2016 are detailed below.

	December 31,	
	2017	2016
	(Thousands)	
Mountain Valley Pipeline, LLC capital call	$105,734	$11,471
Incentive compensation	91,363	100,762
Taxes other than income	78,749	56,874
Accrued interest payable	52,993	39,593
Severance accrual	41,474	338
All other accrued liabilities	60,212	27,681
Total other current liabilities	$430,525	$236,719

Revenue Recognition: Revenue is recognized for production and gathering activities when deliveries of natural gas, NGLs and crude oil occur and title to 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 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. See Recently Issued Accounting Standards within this footnote for further information.

Investments in Consolidated Affiliates: In January 2015, the Company formed EQT GP Holdings, LP (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, 2017, 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).

Following the Rice Merger, the Company owned 100% of the outstanding limited liability company interests in Rice Midstream Management, LLC (the RMP General Partner), the general partner of RMP, and 100% of the general partner and limited partner interests in Rice Midstream GP Holdings, LP (RMGP). As of December 31, 2017, the RMP General Partner owned the entire non-economic general partner interest in RMP, and RMGP owned 3,623 RMP common units and 28,753,623 subordinated units, representing a 28.1% limited partner interest in RMP, and all of RMP's IDRs. On February 15, 2018, the RMP subordinated units issued to RMGP converted into RMP common units on a one-for-one basis.

Each of EQGP, EQM and RMP are 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, 4 and 5.

Strike Force Midstream Holdings LLC (Strike Force Holdings), an indirect wholly owned subsidiary of the Company, owns a 75% limited liability interest in Strike Force Midstream LLC (Strike Force Midstream). The Company consolidates Strike Force

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Midstream and records the noncontrolling interest of the minority owners in its financial statements. Strike Force Holdings results are reported in the results of the EQT Production business segment in Note 13.

Investment in Unconsolidated Entity: Investments in a company 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 investment in the unconsolidated entities 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 12.

Unamortized Debt Discount and Issuance Expense: Discounts and expenses incurred with the issuance of debt are amortized over the term of the debt. These amounts are presented as a reduction of Senior Notes on the accompanying Consolidated Balance Sheets. See Note 15.

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, water 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. 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

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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.

EQT Production's asset retirement obligations related to the abandonment of oil and gas producing facilities include reclaiming drilling sites, plugging wells and dismantling related structures. Estimates are based on historical experience in plugging and abandoning wells and reclaiming or disposing of other assets as well as the estimated remaining lives of the wells and assets. RMP Water's asset retirement obligations relate to dismantling, reclaiming or disposing of water services assets.

The Company is under no legal or contractual obligation to restore or dismantle its gathering systems and transmission and storage system upon abandonment. Additionally, the Company operates and maintains its gathering systems and transmission and storage system and it 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 does not have any asset retirement obligations related to its gathering systems and transmission and storage system as of December 31, 2017 and 2016.

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,	
	2017	2016
	(Thousands)	
Asset retirement obligation as of beginning of period	$ 243,600	$ 168,142
Accretion expense	13,679	9,696
Liabilities incurred	19,678	2,943
Liabilities settled	(3,838)	(1,484)
Liabilities assumed in Rice Merger	50,941	—
Change in estimates	128,610	64,303
Asset retirement obligation as of end of period	$ 452,670	$ 243,600

During 2017 and 2016, the Company had changes in estimates for the plugging of conventional and horizontal wells, primarily related to increased cost assumptions of complying with existing regulatory requirements which were derived, in part, based on recent plugging experience and actual costs incurred. The Company operates in several states that have implemented enhanced requirements that resulted in the use of additional materials during the plugging process which has increased the estimated cost to plug these wells over recent years.

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.

Noncontrolling Interests: Noncontrolling interests represent third-party equity ownership in EQGP, EQM, RMP and Strike Force Midstream 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, 4, and 5 for further discussion of noncontrolling interests related to EQGP, EQM and RMP, respectively, and Note 13 for further discussion of the noncontrolling interest in Strike Force Midstream.

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 Internal Revenue Service (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, during 2016, 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

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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.

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.

Expense recognized by the Company related to its defined contribution plan totaled $16.6 million in 2017, $16.0 million in 2016 and $15.7 million in 2015.

Supplemental Cash Flow Information: Non-cash investing activities for the year ended December 31, 2017 included $143.6 million for asset retirement cost additions, $94.3 million for the increase in the MVP investment as a result of the capital contributions payable, $4.4 million for changes in accruals of property, plant and equipment, $10.0 million of net liabilities assumed in 2017 acquisitions, $(14.3) million for measurement period adjustments for 2016 acquisitions and $9.0 million in capitalized non-cash stock based compensation. See discussion of equity issued in consideration for the Rice Merger in Note 2. Non-cash investing activities for the year ended December 31, 2016 included $87.6 million of net liabilities assumed in acquisitions, $(27.7) million for changes in accruals of property, plant and equipment, $66.2 million for asset retirement cost additions, $11.5 million for the increase in the MVP investment as a result of the capital contributions payable and $16.6 million in capitalized non-cash stock based compensation. Non-cash investing activities for the year ended December 31, 2015 included $(114.8) million for changes in accruals of property, plant and equipment, $7.0 million for asset retirement cost additions, and $25.2 million in capitalized non-cash stock based compensation.

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. 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 No. 2014-09 for annual reporting periods beginning after December 15, 2017. During the third quarter of 2017, the Company substantially completed its detailed review of the impact of the standard on each of its contracts. The Company adopted the ASUs using the modified retrospective method of adoption on January 1, 2018 and did not require an adjustment to the opening balance of equity. The Company does not expect the standard to have a significant impact on its results of operations, liquidity or financial position in 2018. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers including disaggregation of revenue and remaining performance obligations. The Company implemented processes to ensure new contracts are reviewed for the appropriate accounting treatment and generate the disclosures required under the new standard in the first quarter of 2018.

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities. The changes primarily affect the accounting for equity investments, financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. This standard will eliminate the cost method of accounting for equity investments. 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 will adopt this standard in the first quarter of 2018 and does not expect that the adoption of the standard will have a material impact on its financial statements and related disclosures.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The primary effect of adopting the new standard on leases will be to record assets and obligations for contracts currently recognized as operating leases. Lessees and lessors must apply a modified retrospective transition approach. 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. The Company has completed a high level identification of agreements covered by this standard and will continue to evaluate the impact this standard will have on its financial statements, internal controls and related disclosures.

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 Company adopted this standard in the first quarter of 2017 with no significant impact on its financial statements or related disclosures. The Company chose to adopt the classification of excess tax benefits on the statement of cash flows prospectively. Therefore, prior periods have not been adjusted.

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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 ASU will be effective for annual reporting periods beginning after December 15, 2019, including interim periods within that reporting period. 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: 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.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business. This ASU clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. 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.

In January 2017, the FASB issued ASU No. 2017-04, Simplifying the Test of Goodwill Impairment (Topic 350). This ASU simplifies the quantitative goodwill impairment test requirements by eliminating the requirement to calculate the implied fair value of goodwill (Step 2 of the current goodwill impairment test). Instead, a company would record an impairment charge based on the excess of a reporting unit’s carrying value over its fair value (measured in Step 1 of the current goodwill impairment test). This update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. Entities will apply the standard’s provisions prospectively. The Company is currently evaluating the impact that this guidance will have on its consolidated financial statements but currently believes it will not have a material quantitative effect on the financial statements, unless an impairment charge is necessary.

In March 2017, the FASB issued ASU No. 2017-07, Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. This ASU provides additional guidance on the presentation of net benefit cost in the income statement and on the components eligible for capitalization in assets. 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.

In May 2017, the FASB issued ASU No. 2017-09, Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting. This ASU provides guidance regarding which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. The ASU will be effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted. The Company is currently evaluating the impact this standard will have on its financial statements and related disclosures.

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

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2. Rice Merger

On November 13, 2017, the Company completed its previously announced acquisition of Rice Energy Inc. (Rice) pursuant to the Agreement and Plan of Merger, dated as of June 19, 2017 (as amended, the Merger Agreement), by and among the Company, Rice and a wholly owned indirect subsidiary of the Company (RE Merger Sub). Pursuant to the terms of the Merger Agreement, on November 13, 2017, RE Merger Sub merged with and into Rice (the Rice Merger) with Rice continuing as the surviving corporation and a wholly owned indirect subsidiary of the Company. Immediately after the effective time of the Rice Merger (the Effective Time), Rice merged with and into another wholly owned indirect subsidiary of the Company.

At the Effective Time, each share of the common stock, par value $0.01 per share, of Rice (the Rice Common Stock) issued and outstanding immediately prior to the Effective Time was converted into the right to receive 0.37 (the Exchange Ratio) of a share of the common stock, no par value, of the Company (Company Common Stock) and $5.30 in cash (collectively, the Merger Consideration). The aggregate Merger Consideration consisted of approximately 91 million shares of Company Common Stock and approximately $1.6 billion in cash (net of cash acquired and inclusive of amounts payable to employees of Rice who did not continue with the Company following the Effective Time). See Note 18 for further details.

In connection with the closing of the Rice Merger, the Company paid an aggregate of $555.5 million, included in the cash paid for the Merger Consideration of approximately $1.6 billion (net of cash acquired and inclusive of amounts payable to employees of Rice who did not continue with the Company following the Effective Time), to affiliates of EIG Global Energy Partners (collectively, the EIG Funds) to redeem the EIG Funds' respective interests in Rice Midstream Holdings LLC (Rice Midstream Holdings) and RMGP (the EIG Redemptions). Following the EIG Redemptions, each of Rice Midstream Holdings and RMGP are indirect wholly owned subsidiaries of the Company.

In connection with the closing of the Rice Merger, the Company repaid the $321.0 million of outstanding principal under Rice Energy Operating LLC's revolving credit facility and the $187.5 million of outstanding principal under Rice Midstream Holdings' revolving credit facility, together with interest and fees of $1.4 million and $0.3 million, respectively, and the credit agreements were terminated.

Also in connection with the Rice Merger, Rice redeemed and canceled all of its outstanding 6.25% Senior Notes due 2022 (the Rice 2022 Notes) and 7.25% Senior Notes due 2023 (the Rice 2023 Notes) on November 13, 2017. The Company made aggregate payments of $1.4 billion in connection with the note redemptions, including make whole call premiums of $42.2 million and $21.6 million for the Rice 2022 Notes and the Rice 2023 Notes, respectively, and $13.4 million of required interest payments on the Rice 2023 Notes.

The Company acquired a total of approximately 270,000 net acres through the Rice Merger, which includes approximately 205,000 net Marcellus acres, as well as approximately 65,000 net Utica acres in Ohio. The Company also acquired Upper Devonian and Utica drilling rights held in Pennsylvania.

The Company also acquired the interests in RMP disclosed in Note 1.

During the nine months ended September 30, 2017, the Company expensed $8.0 million in debt issuance costs related to a bridge financing commitment to support the Rice Merger. The Company also recorded $237.3 million in acquisition-related expenses related to the Rice Merger during the year ended December 31, 2017. The Rice Merger acquisition related expenses included $75.3 million for stock based compensation and $66.1 million for other compensation arrangements and are included in the Statement of Consolidated Operations Acquisition Costs line.

Rice’s operating revenues represented approximately 10% of the Company’s consolidated operating revenues and Rice's income before income taxes represented approximately 24% of the Company’s consolidated income before income taxes, both for the year ended December 31, 2017.

Allocation of Purchase Price

The Rice Merger has been accounted for as a business combination, using the acquisition method. The following table summarizes the preliminary purchase price and the preliminary estimated fair values of assets and liabilities assumed as of November 13, 2017, with any excess of the purchase price over the estimated fair value of the identified net assets acquired recorded as goodwill. Approximately, $549.2 million and $1,449.5 million of goodwill has been allocated to EQT Production and RMP Gathering, respectively. Goodwill primarily relates to the value of RMP which cannot be assigned to other assets recognized under GAAP as substantially all of RMP's revenues are from affiliates, deferred tax liabilities arising from differences between the purchase price allocated to Rice’s assets and liabilities based on fair value and the tax basis of these assets and liabilities that

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carried over to the Company in the Rice Merger and the Company's ability to control the Rice acquired assets and recognize synergies. Certain data necessary to complete the purchase price allocation is not yet available, including, but not limited to, title defect analysis and final appraisals of assets acquired and liabilities assumed and the finalization of certain income tax computations. The Company expects to complete the purchase price allocation once the Company has received all of the necessary information, at which time the value of the assets and liabilities will be revised as appropriate.

(in thousands)	Preliminary Purchase Price Allocation
Consideration Given:	
Equity consideration	$5,943,289
Cash consideration	1,299,407
Buyout of preferred equity in Rice Midstream Holdings	429,708
Buyout of Common Units in RMGP	125,828
Settlement of pre-existing relationships	(14,699)
Total consideration	7,783,533
Fair value of liabilities assumed:	
Current liabilities	566,774
Long-term debt	2,151,656
Deferred income taxes	1,106,000
Other long term liabilities	67,533
Amount attributable to liabilities assumed	3,891,963
Fair value of assets acquired:	
Cash	294,671
Accounts receivable	337,007
Current assets	109,465
Net property, plant and equipment	9,903,938
Intangible assets	747,300
Noncontrolling interests	(1,715,611)
Amount attributable to assets acquired	9,676,770
Goodwill as of December 31, 2017	$1,998,726

The fair values of natural gas and oil properties are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties were measured using valuation techniques that convert future cash flows into a single discounted amount. Significant inputs to the valuation of natural gas and oil properties included estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average cost of capital. These inputs required significant judgments and estimates by management, are still under review, and may be subject to change. These inputs have a significant impact on the valuation of oil and gas properties and future changes may occur. The fair value of undeveloped property was determined based upon a market approach of comparable transactions using Level 3 inputs.

The estimated fair value of midstream facilities and equipment, generally consisting of pipeline systems and compression stations, is estimated using the cost approach. Significant unobservable inputs in the estimate of fair value include management's assumptions about the replacement costs for similar assets, the relative age of the acquired assets and any potential economic or functional obsolescence associated with the acquired assets. As a result, the estimated fair value of the midstream facilities and equipment represents a level 3 fair value measurement.

The non-controlling interest in the acquired business is comprised of the limited partner units in RMP which were not acquired by EQT as well as the non-controlling interest in Strike Force Midstream. The RMP limited partner units are actively traded on the New York Stock Exchage, and were valued based on observable market prices as of the transaction date and therefore

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represent a level 1 fair value measurement. The non-controlling interest in Strike Force Midstream was calculated based on the enterprise value of Strike Force Midstream and the percentage ownership not acquired by EQT. Significant unobservable inputs in the estimate of the enterprise value of Strike Force Midstream include the future revenue estimates and future cost assumptions. As a result, the non-controlling interest in Strike Force Midstream represents a level 3 fair value measurement.

As part of the preliminary purchase price allocation, the Company identified intangible assets for customer relationships with third party customers and non-compete agreements with certain former Rice executives. The fair value of the identified intangible assets was determined using the income approach which requires a forecast of the expected future cash flows generated and an estimated market-based weighted average cost of capital. Significant unobservable inputs in the determination of fair value include future production levels, future revenues estimates, future cost assumptions, the estimated probability that former executives would compete in the absence of such non-compete agreements and estimated customer retention rates. As a result, the estimated fair value of the identified intangible assets represents a level 3 fair value measurement. Differences between the preliminary purchase price allocation and the final purchase price allocation may change the amount of intangible assets and goodwill ultimately recognized in conjunction with the Rice Merger.

In conjunction with the Rice Merger, the Company has carryover tax basis of $422.5 million of tax deductible goodwill.

Post-Acquisition Operating Results

Subsequent to the completion of the Rice Merger, the acquired entities contributed the following to the Company’s consolidated operating results for the period from November 13, 2017 through December 31, 2017.

(in thousands)	
Revenue attributable to EQT	$323,414
Net income attributable to noncontrolling interests	$16,644
Net income attributable to EQT	$529,743

Net income attributable to EQT includes a tax benefit of $410.9 million for the revaluation of Rice’s net deferred tax liabilities as a result of the Tax Reform Legislation discussed in Note 11.

Unaudited Pro Forma Information

The following unaudited pro forma combined financial information presents the Company’s results as though the Rice Merger had been completed at January 1, 2016. The pro forma combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Rice Merger taken place on January 1, 2016; furthermore, the financial information is not intended to be a projection of future results.

	For the year ended December 31,	
(in thousands, except per share data) (unaudited)	2017	2016
Pro forma operating revenues	$4,809,757	$2,288,605
Pro forma net income (loss)	$2,197,041	$(528,786)
Pro forma net income attributable to noncontrolling interests	$(444,248)	$(401,149)
Pro forma net income (loss) attributable to EQT	$1,752,793	$(929,935)
Pro forma income (loss) per share (basic)	$6.30	$(3.59)
Pro forma income (loss) per share (diluted)	$6.29	$(3.59)

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3. EQT GP Holdings, LP

At December 31, 2017 and 2016, EQGP owned the following EQM partnership interests, 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 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.

The Company received net proceeds from EQGP's 2015 IPO 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 18, 2018, the Board of Directors of EQGP's general partner declared a cash distribution to EQGP's unitholders for the fourth quarter of 2017 of $0.244 per common unit, or approximately $64.9 million. The cash distribution will be paid on February 23, 2018 to unitholders of record, including the Company, at the close of business on February 2, 2018.

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 Equity Offerings: The following table summarizes EQM's public offerings of its common units during the three years ended December 31, 2017.

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

(a) The underwriters exercised their option to purchase additional common units. EQM Midstream Services, LLC, the general partner of EQM (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.

(b) 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

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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.

(c) EQM used the net proceeds for general partnership purposes and to repay amounts outstanding under EQM's revolving 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.

(d) 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: In the ordinary course of business, EQT engages in transactions with EQM including, but not limited to, gas gathering and transmission agreements.

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 15, 2018, 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. On October 13, 2017, the FERC issued the Certificate of Public Convenience and Necessity for the project. In early 2018, the MVP Joint Venture received limited notice to proceed with certain construction activities from the FERC. The MVP Joint Venture plans to commence construction in the first quarter of 2018. The pipeline is targeted to be placed in-service during the fourth quarter of 2018. See Note 12.

On October 13, 2016, 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 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 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 1, 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.

The expenses for which EQM reimburses EQT and its subsidiaries related to corporate and general and administrative services may not necessarily reflect the actual expenses that EQM would incur on a stand-alone basis. EQM is unable to estimate what the costs would have been with an unrelated third party.

EQM has a $500 million, 364-day, uncommitted revolving loan agreement with EQT that matures on October 24, 2018 and will automatically renew for successive 364-day periods unless EQT delivers a non-renewal notice at least 60 days prior to the then current maturity date (the 364-Day Facility). 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 $1 billion revolving credit facility, or a successor revolving credit facility, less the sum of (i) the then applicable commitment fee under EQM's $1 billion revolving credit facility and (ii) 10 basis points. EQM had no borrowings outstanding under the 364-Day Facility as of December 31, 2017. During the year ended December 31, 2017, the maximum amount of EQM’s outstanding borrowings under the credit facility at any time was $100 million and the average daily balance was approximately $23 million.

For the year ended December 31, 2017, interest was incurred at a weighted average annual interest rate of approximately 2.2%. There were no amounts outstanding at any time on the 364-Day Facility in 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 revolving 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.

See Note 14 for discussion of EQM's $1.0 billion credit facility.

On January 18, 2018, the Board of Directors of EQM’s general partner declared a cash distribution to EQM’s unitholders for the fourth quarter of 2017 of $1.025 per common unit. The cash distribution was paid on February 14, 2018 to unitholders of record, including EQGP, at the close of business on February 2, 2018. Cash distributions by EQM to EQGP were approximately $65.7 million consisting of: $22.4 million in respect of its limited partner interest, $2.2 million in respect of its general partner interest and $41.1 million in respect of its IDRs in EQM.

5. Rice Midstream Partners LP

RMP owns, operates and develops midstream assets in the Appalachian Basin. RMP's assets consist of gathering pipelines and compressor stations, as well as water handling and treatment facilities. RMP provides gathering and water services to the Company and third parties. The Company is the ultimate parent company of RMP, and the Company records the noncontrolling interest of the RMP public limited partners in its financial statements.

On January 18, 2018, the Board of Directors of the RMP General Partner declared a cash distribution to RMP’s unitholders for the fourth quarter of 2017 of $0.2917 per common and subordinated unit. The cash distribution was paid on February 14, 2018 to unitholders of record at the close of business on February 2, 2018. Cash distributions by RMP to RMGP were approximately $11.4 million, consisting of $8.4 million in respect of its limited partner interest and $3.0 million in respect of its IDRs in RMP.

On the closing date of the Rice Merger, in connection with the completion of the Rice Merger, RMP, EQT and various other EQT subsidiaries entered into an Amended and Restated Omnibus Agreement, pursuant to which RMP is obligated to reimburse EQT for the provision of general and administrative services for its benefit, for direct expenses incurred by EQT on RMP’s behalf, for expenses allocated to it as a result of being a public entity and for an allocated portion of the compensation expense of the executive officers and other employees of EQT and its affiliates who perform centralized corporate and general and administrative services on substantially the same terms as the original omnibus agreement.

See Note 14 for discussion of RMP's $850 million credit facility.

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6. Financial Information by Business Segment

Year Ended December 31, 2017	EQT Production (Thousands)	EQM Gathering	EQM Transmission	RMP Gathering	RMP Water	Intersegment Eliminations	EQT Corporation
Revenues:							
Sales of natural gas, oil and NGLs	$2,651,318	$—	$ —	$ —	$—	$—	$2,651,318
Pipeline, water and net marketing services	64,998	454,536	379,560	30,614	13,605	(606,637)	336,676
Gain on derivatives not designated as hedges	390,021	—	—	—	—	—	390,021
Total operating revenues	$3,106,337	$454,536	$ 379,560	$ 30,614	$13,605	$ (606,637)	$3,378,015

Year Ended December 31, 2016	EQT Production (Thousands)	EQM Gathering	EQM Transmission	Intersegment Eliminations	EQT Corporation
Revenues:					
Sales of natural gas, oil and NGLs	$1,594,997	$—	$ —	$—	$1,594,997
Pipeline and net 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)	EQM Gathering	EQM Transmission	Intersegment Eliminations	EQT Corporation
Revenues:					
Sales of natural gas, oil and NGLs	$1,690,360	$—	$ —	$—	$1,690,360
Pipeline and net 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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	Years Ended December 31,		
	2017	2016	2015
		(Thousands)	
Operating income (loss):			
EQT Production (a)	$589,716	$(719,731)	$132,008
EQM Gathering	333,563	289,027	243,257
EQM Transmission	247,145	237,922	207,779
RMP Gathering (b)	21,800	—	—
RMP Water (b)	4,145	—	—
Unallocated expenses (c)	(263,388)	(85,518)	(19,905)
Total operating income (loss)	$932,981	$(278,300)	$563,139
Reconciliation of operating income (loss) to net income (loss):			
Total operating income (loss)	$932,981	$(278,300)	$563,139
Other income	24,955	31,693	9,953
Loss on debt extinguishment	12,641	—	—
Interest expense	202,772	147,920	146,531
Income tax (benefit) expense	(1,115,619)	(263,464)	104,675
Net income (loss)	$1,858,142	$(131,063)	$321,886

(a) For the year ended December 31, 2017, the operating income for EQT Production includes the results of operations for the production operations and retained midstream operations acquired in the Rice Merger for the period of November 13, 2017 through December 31, 2017. See Note 2 for a discussion of the Rice Merger. Gains on sales / exchanges of assets of $8.0 million are included in EQT Production operating income for 2016. See Note 9. Impairment of long-lived assets of $6.9 million and $122.5 million are included in EQT Production operating income for 2016 and 2015, respectively. See Note 1 for a discussion of impairment of long-lived assets.

(b) Operating income for RMP Gathering and RMP Water, both acquired in the Rice Merger, includes the results of operations for the period of November 13, 2017 through December 31, 2017. See Note 2 for a discussion of the Rice Merger.

(c) Unallocated expenses generally include incentive compensation expense and administrative costs. In addition, 2017 includes $237.3 million of Rice Merger related expenses and 2016 includes a $59.7 million impairment on gathering assets prior to the sale to EQM.

	As of December 31,		
	2017	2016	2015
	(Thousands)		
Segment assets:			
EQT Production	$22,711,854	$10,923,824	$9,905,344
EQM Gathering	1,411,857	1,225,686	1,019,004
EQM Transmission	1,462,881	1,399,201	1,169,517
RMP Gathering	2,720,305	—	—
RMP Water	185,079	—	—
Total operating segments	28,491,976	13,548,711	12,093,865
Headquarters assets, including cash and short-term investments	1,030,628	1,924,211	1,882,307
Total assets	$29,522,604	$15,472,922	$13,976,172

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	Years Ended December 31,		
	2017	2016	2015
		(Thousands)	
Depreciation, depletion and amortization: (d)			
EQT Production (e)	$982,103	$859,018	$765,298
EQM Gathering	38,796	30,422	24,360
EQM Transmission (g)	58,689	32,269	25,535
RMP Gathering (f)	3,965	—	—
RMP Water (f)	3,515	—	—
Other (g)	(9,509)	6,211	4,023
Total	$1,077,559	$927,920	$819,216
Expenditures for segment assets: (h)			
EQT Production (e) (i)	$2,430,094	$2,073,907	$1,893,750
EQM Gathering	196,871	295,315	225,537
EQM Transmission	111,102	292,049	203,706
RMP Gathering (f) (j)	28,320	—	—
RMP Water (f) (j)	6,233	—	—
Other	6,080	7,002	21,421
Total	$2,778,700	$2,668,273	$2,344,414

(d) Excludes amortization of intangible assets.

(e) For the year ended December 31, 2017, depreciation, depletion and amortization expense and expenditures for segment assets for EQT Production includes activity for the production operations and retained midstream operations acquired in the Rice Merger for the period of November 13, 2017 through December 31, 2017. See Note 2 for a discussion of the Rice Merger.

(f) Depreciation, depletion and amortization expense and expenditures for segment assets for RMP Gathering and RMP Water, both acquired in the Rice Merger, includes activity for the period of November 13, 2017 through December 31, 2017. See Note 2 for a discussion of the Rice Merger.

(g) Depreciation, depletion and amortization expense for EQM Transmission includes a non-cash charge of $10.5 million related to the revaluation of differences between the regulatory and tax bases in EQM's regulated property, plant and equipment. For purposes of consolidated reporting at EQT, the $10.5 million is recorded to income tax expense. This reclass is shown as a reduction of other depreciation, depletion and amortization expense.

(h) 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 $9.1 million, $76.5 million and $(89.6) million for the years ended December 31, 2017, 2016 and 2015, 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, 2017 included $10.0 million of non-cash capital expenditures related to 2017 acquisitions and $(14.3) million of measurement period adjustments for 2016 acquisitions. The year ended December 31, 2016 included $87.6 million of non-cash capital expenditures related to 2016 acquisitions. See Note 10 for discussion of the 2017 and 2016 acquisitions. Expenditures for segment assets does not include consideration for the Rice Merger.

(i) Expenditures for segment assets in the EQT Production segment included $1,006.7 million, $1,284.0 million and $182.3 million for property acquisitions in 2017, 2016 and 2015, respectively. Included in the $1,006.7 million of property acquisitions for the year ended December 31, 2017 was $819.0 million of cash capital expenditures and $10.0 million of non-cash capital expenditures related to 2017 acquisitions and $(14.3) million of measurement period adjustments for 2016 acquisitions (see Note 10). 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 10).

(j) Expenditures for segment assets in the RMP Gathering and RMP Water segments included $17.1 million in cash paid by EQT for capital expenditures accrued as of the opening balance sheet date of the Rice Merger.

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7. 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, collar and option agreements that are typically 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 swaptions and 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.

The Company discontinued cash flow hedge accounting in 2014; therefore, all changes in fair value of the Company’s derivative instruments are recognized within operating revenues in the Statements of Consolidated Operations.

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. As of December 31, 2017, 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, 2017, and 2016, the Company deferred net gains of $4.6 million and $9.6 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 $4.6 million of net gains on its derivative commodity instruments reflected in accumulated OCI, net of tax, as of December 31, 2017 will be recognized in earnings during the next twelve months due to the settlement of hedged transactions.

In connection with the Rice Merger, the Company assumed all outstanding derivative commodity instruments held by Rice. The assets and liabilities assumed were recognized at fair value at the closing date and subsequent changes in fair value were recognized within operating revenues in the Statements of Consolidated Operations. The derivative commodity instruments assumed were substantially similar to instruments previously held by the Company.

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.

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 2,148 Bcf of natural gas and 8,943 Mbbls of NGLs as of December 31, 2017, and 646 Bcf of natural gas and 1,095 Mbbls of NGLs as of December 31, 2016. The open positions at December 31, 2017 and December 31, 2016 had maturities extending through December 2022 and December 2020, respectively.

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, 2017 or 2016.

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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, 2017 and 2016.

As of December 31, 2017	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	$241,952	$(86,856)	$ —	$ 155,096
Liability derivatives:				
Derivative instruments, at fair value	$139,089	$(86,856)	$ —	$ 52,233

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

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 if the amounts outstanding on those contracts exceed certain thresholds. The additional collateral can be up to 100% of the derivative liability. As of December 31, 2017, the aggregate fair value of all derivative instruments with credit risk-related contingent features that were in a net liability position was $60.8 million, for which the Company had no collateral posted on December 31, 2017. If the Company’s credit rating by S&P or Moody’s had been downgraded below investment grade on December 31, 2017, the Company would not have been required to post any additional collateral under the agreements with the respective counterparties. The required margin on the Company's derivative instruments is 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 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, 2017. 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.

8. 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, collar and option 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) natural gas and propane

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forward curves, LIBOR-based discount rates, and basis forward curves. The Company's collars, options, and swaptions 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 natural gas and propane forward curves, LIBOR-based discount rates, natural gas volatilities and basis forward curves are validated to external sources at least monthly.

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

		Fair value measurements at reporting date using		
Description	As of December 31, 2017	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(Thousands)			
Assets				
Derivative instruments, at fair value	$241,952	$ —	$ 241,952	$ —
Liabilities				
Derivative instruments, at fair value	$139,089	$ —	$ 139,089	$ —

		Fair value measurements at reporting date using		
Description	As of December 31, 2016	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	$ —

The carrying values of cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value due to the short-term maturity of the instruments. The carrying values of borrowings under the Company's various credit facilities approximate fair value as the interest rates are based on prevailing market rates.

The fair values of trading securities classified as Level 2 were priced using nonbinding market prices that were 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, 2017.

The Company estimates the fair value of its Senior Notes using its established fair value methodology. Because not all of the Company's Senior notes are actively traded, the fair value of the Senior Notes is a Level 2 fair value measurement. Fair value for non-traded Senior Notes 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 Senior Notes (including EQM's Senior Notes) on the Consolidated Balance Sheets at December 31, 2017 and 2016 was approximately $5.7 billion and $3.5 billion, respectively. The carrying value of Senior Notes (including EQM's Senior Notes) on the Consolidated Balance Sheets at December 31, 2017 and 2016 was approximately $5.6 billion and $3.3 billion, respectively. Refer to Notes 14 and 15 for further information regarding the Company's and EQM's debt as of December 31, 2017 and 2016.

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.

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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 Rice Merger and the assets acquired in other acquisition transactions, see Notes 1, 2, and 10.

9. Sales/Exchanges of Assets

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.

10. Acquisitions

In addition to the Rice Merger discussed in Note 2, the Company executed multiple transactions during 2016 and 2017 that resulted in the Company's acquisition of approximately 304,000 net Marcellus acres, including the transactions listed below:

- 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 of West Virginia.

- In the fourth quarter of 2016, the Company acquired approximately 42,600 net Marcellus acres and 42 Marcellus wells, 32 of which were producing at the time of the acquisition, 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 of 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 (TE 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, TE 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 of Pennsylvania, and two related Marcellus wells both of which were producing (the 2016 Pennsylvania Acquisition).

- On February 1, 2017, the Company acquired approximately 14,000 net Marcellus acres located in Marion, Monongalia and Wetzel Counties of West Virginia from a third party.

- On February 27, 2017, the Company acquired approximately 85,000 net Marcellus acres, including drilling rights on approximately 44,000 net Utica acres and current natural gas production of approximately 110 MMcfe per day, from Stone Energy Corporation. The acquired acres are primarily located in Wetzel, Marshall, Tyler and Marion Counties of West Virginia. The acquired assets also included 174 Marcellus wells, 120 of which were producing at the time of the acquisition, and 20 miles of gathering pipeline.

- On June 30, 2017, the Company acquired approximately 11,000 net Marcellus acres, and the associated Utica drilling rights, from a third party. The acquired acres are primarily located in Allegheny, Washington and Westmoreland Counties of Pennsylvania.

In total, the Company paid net cash of $740.1 million during the year ended December 31, 2017 for the 2017 acquisitions noted above. The 2017 acquisitions purchase prices remain subject to customary post-closing adjustments as of December 31, 2017. The preliminary fair value assigned to the acquired property, plant and equipment from the 2017 acquisitions as of the opening balance sheet dates totaled $750.1 million. In connection with the 2017 acquisitions, the Company assumed approximately $5.3 million of net current liabilities and $4.7 million of non-current liabilities. The amounts presented in the financial statements represent the Company's estimates based on preliminary valuations of acquired assets and liabilities and are subject to change based on the Company's finalization of asset and liability valuations.

As a result of post-closing adjustments on its 2016 acquisitions, the Company paid $78.9 million for additional undeveloped acreage, included in the $1,130.1 million net cash in connection with the 2016 acquisitions disclosed above, and recorded other

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non-cash adjustments which reduced the preliminary fair values assigned to the acquired property, plant and equipment by $14.3 million, during the year ended December 31, 2017.

In total, the Company paid $1,130.1 million in net cash in connection with the 2016 acquisitions noted above. The fair value assigned to the acquired property, plant and equipment as of the opening balance sheet dates totaled $1,203.4 million: $256.2 million allocated to the acquired producing wells and $947.2 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 $14.4 million of current liabilities and $11.1 million of non-current liabilities. The $14.4 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 $49.0 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 forward pricing estimates. As a result, valuation of the acquired assets was a Level 3 measurement.

11. Income Taxes

Income tax (benefit) expense is summarized as follows:

	Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Current:			
Federal	$(65,034)	$(82,905)	$85,696
State	27	(298)	1,103
Subtotal	(65,007)	(83,203)	86,799
Deferred:			
Federal	(998,483)	(117,155)	(109,642)
State	(52,129)	(63,106)	127,518
Subtotal	(1,050,612)	(180,261)	17,876
Total income taxes	$(1,115,619)	$(263,464)	$104,675

The Company recorded a current federal income tax benefit in 2017 primarily as a result of carrying back federal and alternative minimum tax (AMT) net operating losses (NOLs) generated in 2016 and 2017. The Company will file carryback claims requesting a refund of a portion of the amounts paid relating to the 2015 federal tax return. The current federal income tax benefit in 2016 primarily related to amended return refund claims filed in 2016 and 2017 for open tax years 2010 through 2013. The current federal and state income tax expense in 2015 primarily related to tax gains generated as a result of EQGP's IPO and the sale of NWV Gathering to EQM in that year.

On December 22, 2017, the U.S. Congress enacted the law known as the Tax Cuts and Jobs Act of 2017 (Tax Reform Legislation), which made significant changes to U.S. federal income tax law, including lowering the federal corporate tax rate to 21% from 35% beginning January 1, 2018. As a result of the change in the corporate tax rate the Company recorded a deferred tax benefit of $1.2 billion during the year ended December 31, 2017 to revalue its existing net deferred tax liabilities to the lower rate.

The Tax Reform Legislation preserved deductibility of intangible drilling costs (IDCs) for federal income tax purposes, which allows the Company to deduct a portion of drilling costs in the year incurred and minimizes current taxes payable in periods of taxable income. IDCs have historically been limited for AMT purposes, which has resulted in the Company paying AMT in periods when no other federal taxes were currently payable. The Tax Reform Legislation also repealed the AMT for tax years beginning January 1, 2018 and provides that existing AMT credit carryforwards can be utilized to offset current federal taxes owed in tax years 2018 through 2020. In addition, 50% of any unused AMT credit carryforwards can be refunded during these years with any remaining AMT credit carryforward being fully refunded in 2021. The Company had approximately $435 million of AMT credit carryforward as of December 31, 2017.

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The Tax Reform Legislation contains several other provisions, such as limiting the deductibility of interest expense, that are not expected to have a material effect on the Company's results of operations. As of December 31, 2017, the Company has not completed its accounting for the effects of the Tax Reform Legislation; however, provisional amounts are recorded to revalue deferred tax assets and liabilities and reflect the state income tax effects related to the Tax Reform Legislation. The Company also considered whether existing deferred tax amounts will be recovered in future periods under the new law. However, the Company is still analyzing certain aspects of the Tax Reform Legislation and refining calculations, which could potentially impact the measurement of these balances or potentially give rise to new deferred tax amounts. The Company will refine its estimates to incorporate new or better information as it comes available through the filing date of its 2017 U.S. income tax returns in the fourth quarter of 2018.

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 forward. The PATH Act also reinstated and extended through the end of 2017 50% bonus depreciation. In addition, the Tax Reform Legislation provides for 100% bonus depreciation on some tangible property expenditures through 2022.

The Company has federal NOL carryforwards related to the Rice Merger discussed in Note 2 and NOLs generated in 2017 in excess of the amount carried back to 2015. The Company also has NOLs related to the Trans Energy Merger discussed in Note 10, of which a nominal amount is available to be utilized annually over the next 20 years. The Tax Reform Legislation limits the utilization of NOLs generated after December 31, 2017 that are carried forward into future years to 80% of taxable income and eliminates the ability to carry NOLs back to earlier tax years for refunds of taxes paid.

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

	Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Tax at statutory rate	$259,884	$(138,084)	$149,296
Federal tax reform	(1,205,140)	—	—
State income taxes	(52,606)	(71,613)	(7,566)
Valuation allowance	10,680	23,808	91,144
Noncontrolling partners’ share of earnings	(122,365)	(112,672)	(82,850)
Regulatory liability/asset	10,488	35,438	(35,438)
Federal tax credits	(34,956)	(4,539)	(7,243)
Other	18,396	4,198	(2,668)
Income tax (benefit) expense	$(1,115,619)	$(263,464)	$104,675
Effective tax rate	(150.2)%	66.8%	24.5%

All of EQGP's, RMP’s and Strike Force Midstream’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 portion of EQGP's and RMP’s income allocated to the noncontrolling public limited partners of EQGP, EQM and RMP or to the portion of Strike Force Midstream’s income allocated to the minority owner, 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 effective tax rate for the year ended December 31, 2017 was lower than the U.S. federal statutory rate primarily due to the effect of the Tax Reform Legislation. The primary impact of the Tax Reform Legislation on the Company's effective tax rate was to revalue the Company's deferred tax liability at the new corporate tax rate of 21%. The effective tax rate was also lower due to the effect of income allocated to the noncontrolling limited partners of EQGP, EQM and RMP and the minority owner of Strike Force Midstream as well as for federal tax credits generated during the year. These credits increased for the year ended December 31, 2017 as a result of $30.2 million of federal marginal well tax credit. The IRS Notice supporting the calculation of the credit was not published until 2017 and the Company was unable to estimate the amount of this credit absent the IRS Notice. As a result, $6.1 million of this credit recorded in 2017 related to 2016 activity.

For the year ended December 31, 2017, the Company realized a $10.5 million tax expense associated with FERC regulated assets as a result of the corporate tax rate reduction in the Tax Reform Legislation. Following the normalization rules of the IRC, this regulatory liability is amortized on a straight-line basis over the estimated remaining life of the related assets.

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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 paragraph.

For the year ended December 31, 2015, the Company realized a $35.4 million regulatory asset tax benefit in connection with 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 IRC, 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 and certain federal NOLs acquired in recent acquisitions 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, 2017, 2016 and 2015, positive evidence considered included 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 historical pre-tax book losses of the EQT Production business segment. A review of positive and negative evidence regarding these tax benefits resulted in the conclusion that valuation allowances for certain NOLs were warranted as it was more likely than not that the Company would not utilize them 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. 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 the related valuation allowances in future periods that could materially impact net income.

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

	2017	2016	2015
	(Thousands)		
Balance at January 1	$252,434	$259,301	$56,957
Additions based on tax positions related to current year	50,469	23,978	152,983
Additions for tax positions of prior years	8,978	20,336	50,688
Reductions for tax positions of prior years	(10,323)	(51,181)	(1,327)
Lapse of statute of limitations	—	—	—
Balance at December 31	$301,558	$252,434	$259,301

Included in the balance above are unrecognized tax benefits that, if recognized, would affect the effective tax rate of $120.5 million, $102.0 million and $94.1 million as of December 31, 2017, 2016 and 2015, respectively. Additionally, there were uncertain tax positions included in the balance above of $84.1 million, $75.4 million, and $114.2 million for the years ended December 31, 2017, 2016 and 2015, respectively, that have been recorded in the Consolidated Balance Sheets as a reduction of the related deferred tax asset for AMT credit carryforwards and NOLs. The deferred tax asset was reduced for uncertain tax positions of approximately $0.3 million and $0.5 million during the years ended December 31, 2017 and 2016, respectively.

Included in the tabular reconciliation above at December 31, 2017, 2016 and 2015 are $4.7 million, $5.5 million and $6.4 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. 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 $3.2 million, $1.6 million and $1.6 million for 2017, 2016 and 2015, respectively. Interest and penalties of $8.4 million, $5.2 million and $3.6 million were included in the Consolidated Balance Sheets at December 31, 2017, 2016 and 2015, respectively.

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As of December 31, 2017, the Company believed that it is reasonably possible that a decrease of $42.5 million in unrecognized tax benefits related to federal tax positions may be necessary within 12 months as a result of potential settlements with, or legal or administrative guidance by, relevant taxing authorities or the lapse of applicable statutes of limitation. As of December 31, 2016 and 2015, the Company did not expect any of its unrecognized tax benefits to decrease within the next 12 months.

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, 2017, 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 2017.

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,	
	2017	2016
	(Thousands)	
Deferred income taxes:		
Total deferred income tax assets	$(971,184)	$(875,303)
Total deferred income tax liabilities	2,740,084	2,635,307
Total net deferred income tax liabilities	1,768,900	1,760,004
Total deferred income tax liabilities (assets):		
Drilling and development costs expensed for income tax reporting	2,074,091	1,473,355
Tax depreciation in excess of book depreciation	644,590	1,161,952
Incentive compensation and deferred compensation plans	(43,822)	(77,743)
Net operating loss carryforwards	(564,180)	(282,943)
Investment in partnerships	(132,667)	(386,676)
Alternative minimum tax credit carryforward	(435,190)	(224,428)
Federal tax credits	(50,341)	(2,508)
Unrealized hedge (losses) gains	21,403	(101,430)
Other	(7,376)	(997)
Total excluding valuation allowances	1,506,508	1,558,582
Valuation allowances	262,392	201,422
Total net deferred income tax liabilities	$1,768,900	$1,760,004

The net deferred tax liability decrease of $1.2 billion as a result of the decrease in the corporate tax rate in the Tax Reform Legislation and was partially offset by a $1.1 billion net deferred tax liability recognized as a result of the Rice Mergers discussed in Note 2.

As of December 31, 2017, the Company had a deferred tax asset of $194.3 million, net of valuation allowances of $22.9 million, related to tax benefits from federal NOL carryforwards expiring in 2036 to 2037. As of December 31, 2017, the Company had a deferred tax asset of $130.0 million, net of valuation allowances of $217.0 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2018 to 2037. On October 30, 2017, Pennsylvania enacted a change in the limitation on Pennsylvania NOL utilization to 35% of taxable income from 30% of taxable income for tax years beginning in 2018 and to 40% of taxable income for tax years beginning in

2019 and thereafter. As a result, the Company's valuation allowance for state NOLs was reduced by $21.2 million during 2017. In addition, the Company recorded a valuation allowance of $22.5 million on AMT credits related to the federal sequestration of refunds, which reduces refunds claims for NOLs by 6.6% in fiscal 2017. 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 state NOL carryforwards with various expiration dates ranging from 2018 to 2035.

As discussed in Note 1, effective for the year ended December 31, 2017, EQT adopted ASU No. 2016-09 to simplify accounting for employee share-based payment transactions and eliminated excess tax benefits. The Company recorded tax benefits

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of $0.9 million for the year ended December 31, 2016, in the Consolidated Financial Statements as additions to common shareholders' equity, which reduced taxes payable for the respective year.

12. 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, 2017	As of December 31, 2017	2016
				(Thousands)	
MVP Joint Venture	USA	Joint	45.5%	$460,546	$184,562

The Company recorded equity income for 2017, 2016 and 2015 related to the MVP Joint Venture of $22.2 million, $9.9 million and $2.6 million, respectively, within other income on the Statements of Consolidated Operations.

In December 2017, the MVP Joint Venture issued a capital call notice to MVP Holdco for $105.7 million, of which $27.2 million was paid in January 2018 and the remaining $78.5 million is expected to be paid in February 2018. The capital contribution payable is recorded in other current liabilities on the Consolidated Balance Sheet as of December 31, 2017 with a corresponding increase to investment in unconsolidated subsidiary.

The MVP Joint Venture has been determined to be a variable interest entity because it 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, 2017, 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.

As of December 31, 2017, EQM's maximum financial statement exposure related to the MVP Joint Venture was approximately $551.5 million, which consists of the investment in nonconsolidated entity balance of $460.5 million on the Consolidated Balance Sheet as of December 31, 2017 and amounts which could have become due under EQM's performance guarantee as of that date.

13. 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. Following the Rice Merger, the Company concluded that RMP and

Strike Force Midstream each meet the criteria for variable interest entity classification. Through EQT's ownership and control of EQGP's general partner, EQM's general partner, RMP's general partner and Strike Force Midstream Holdings, EQT has the power to direct the activities that most significantly impact the economic performance of EQGP, EQM, RMP and Strike Force Midstream. 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. Furthermore, through EQT's general partner interest, limited partner interest and IDRs in RMP and majority ownership interest in Strike Force Midstream, EQT has the obligation to absorb the losses of RMP and Strike Force Midstream and the right to receive benefits from RMP and Strike Force Midstream, in accordance with such interests. As EQT has a controlling financial interest in EQGP, EQM, RMP and Strike Force Midstream and is the primary beneficiary, EQT consolidates EQGP, EQM, RMP and Strike Force Midstream.

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The key risks associated with the operations of EQGP, EQM, RMP and Strike Force Midstream, as applicable, 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 and RMP depend on EQT for a substantial majority of their revenues and future growth; therefore, EQM and RMP are indirectly subject to the business risks of EQT;
- EQM's natural gas gathering, transmission and storage services, RMP's natural gas gathering, compression and water services, and Strike Force Midstream's gathering and compression 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, RMP and Strike Force Midstream to significant costs and liabilities;
- Expanding EQM, RMP and Strike Force Midstream's businesses by constructing new midstream assets subjects EQM, RMP, and Strike Force Midstream to risks. If EQM, RMP and Strike Force Midstream do not complete these expansion projects, their future growth may be limited;
- EQM, RMP and Strike Force Midstream are subject to numerous hazards and operational risks which include, but are not limited to, ruptures, fires, explosions, leaks and damage to pipelines, facilities, equipment and surrounding properties caused by natural disasters, acts of sabotage and terrorism, and inadvertent damage; and
- 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.

See further discussion of the impact that EQT's ownership and control of EQM, EQGP , RMP and Strike Force Midstream have on EQT's financial position, results of operations and cash flows in Notes 3, 4 and 5 for EQM, EQGP, and RMP, respectively, and in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report on Form 10-K for the year ended December 31, 2017.

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, 2017 and 2016.

Classification	December 31, 2017	December 31, 2016
	(Thousands)	
Assets:		
Cash and cash equivalents	$2,857	$ 60,453
Accounts receivable	28,804	20,662
Prepaid expenses and other	8,470	5,745
Property, plant and equipment, net	2,804,059	2,578,834
Other assets	483,004	206,104
Liabilities:		
Accounts payable	$47,042	$ 35,831
Other current liabilities	133,531	32,242
Credit facility borrowings	180,000	—
Senior Notes	987,352	985,732
Other liabilities and credits	20,273	9,562

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The following table summarizes EQGP and EQM's Statements of Consolidated Operations and Cash Flows for the years ended December 31, 2017, 2016 and 2015, inclusive of affiliate amounts.

	Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Operating revenues	$834,096	$735,614	$632,936
Operating expenses	256,403	211,630	183,956
Other (expenses) income	(8,773)	11,010	(14,980)
Net income	$568,920	$534,994	$434,000
Net cash provided by operating activities	$647,828	$535,357	$488,329
Net cash used in investing activities	$(456,968)	$(732,033)	$(1,043,822)
Net cash (used in) provided by financing activities	$(248,456)	$(103,828)	$735,712

The following table presents summary information of assets and liabilities of RMP included in the Company’s Consolidated Balance Sheets that are for the use or obligation of RMP.

Classification	December 31, 2017
	(Thousands)
Assets:	
Cash	$ 10,538
Accounts receivable	12,246
Other current assets	1,327
Property and equipment, net	1,431,802
Goodwill	1,346,918
Liabilities:	
Accounts payable	$ 4
Other current liabilities	28,830
Credit facility borrowings	286,000
Other long-term liabilities	9,360

The following table presents summary information for RMP’s financial performance included in the Consolidated Statements of Operations and Cash Flows for the period from November 13, 2017 through December 31, 2017, inclusive of affiliate amounts.

	For the period November 13, 2017 through December 31, 2017
	(Thousands)
Operating revenues	$ 44,219
Operating expenses	18,274
Other expenses	(811)
Net income	$ 25,134

Net cash provided by operating activities	$ 22,430
Net cash used in investing activities	$ (34,553)
Net cash provided by financing activities	$ 9,959

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The following table presents summary information of assets and liabilities of Strike Force Midstream included in the Company's Consolidated Balance Sheets that are for the use or obligation of Strike Force Midstream.

	December 31, 2017 (Thousands)
Assets:	
Cash	$ 43,938
Accounts receivable	12,477
Property and equipment, net	356,346
Intangible Assets	457,992
Liabilities:	
Other current liabilities	$ 24,341

The following table presents summary information for Strike Force Midstream's financial performance included in the Consolidated Statements of Operations and Cash Flows for the period from November 13, 2017 through December 31, 2017, inclusive of affiliate amounts.

	For the period November 13, 2017 through December 31, 2017 (in thousands)
Operating revenues	$ 9,214
Operating expenses	6,330
Other (expenses) income	52
Net income	$ 2,936
Net cash provided by operating activities	$ 8,588
Net cash used in investing activities	$ (36,190)
Net cash provided by financing activities	$ 26,951

14. Revolving Credit Facilities

EQT $2.5 Billion Facility

In July 2017, the Company amended and restated its $1.5 billion revolving credit facility to extend the term to July 2022. The Company may request two one-year extensions of the expiration date, the approval of which is subject to satisfaction of certain conditions. On November 13, 2017, in connection with the consummation of the Rice Merger, the aggregate commitments of the lenders under the credit facility increased from $1.5 billion to $2.5 billion. Subject to certain terms and conditions, the Company may, on a one-time basis, request that the lenders' commitments be increased to an aggregate of up to $3.0 billion. Each lender in the facility may decide if it will increase its commitment. The 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 19 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company.

Under the terms of the credit facility, the Company may obtain base rate loans or fixed period Eurodollar rate loans denominated in U.S. dollars. Base rate loans 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 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 the credit facility in addition to the interest rate charged by the counterparties on any amounts borrowed against the credit facility; the lower the Company's debt credit rating, the higher the level of fees and borrowing rate.

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The Company had $1.3 billion of borrowings and $159.4 million letters of credit outstanding under its credit facility as of December 31, 2017. 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. The Company incurred commitment fees averaging approximately 20, 23 and 23 basis points for the years ended December 31, 2017, 2016 and 2015, respectively, to maintain credit availability under its credit facility.

The maximum amount of outstanding borrowings at any time under the credit facility during the year ended December 31, 2017 was $1.4 billion, and the average daily balance of borrowings outstanding was approximately $190.9 million at a weighted average annual interest rate of approximately 2.8%.

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 credit facility relate to maintenance of a debt-to-total capitalization ratio and limitations on transactions with affiliates. The 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 OCI. As of December 31, 2017, the Company was in compliance with all debt provisions and covenants.

EQM $1.0 Billion Facility

In July 2017, EQM amended and restated its credit facility to increase the borrowing capacity under the facility from $750 million to $1 billion and to extend the term to July 2022. Subject to certain terms and conditions, the $1 billion credit facility has an accordion feature that allows EQM to increase the available borrowings under the facility by up to an additional $500 million. Each lender in the facility may decide if it will increase its commitment. 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 19 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. Obligations under the revolving portion of the credit facility are unsecured.

Under the terms of its credit facility, EQM may obtain base rate loans or fixed period Eurodollar rate loans denominated in U.S. dollars. Base rate loans 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 is not required to maintain compensating bank balances under its $1 billion 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 credit facility; the lower EQM's debt credit rating, the higher the level of fees and borrowing rate.

EQM had $180.0 million borrowings and no letters of credit outstanding under its $1 billion credit facility as of December 31, 2017. EQM had no borrowings and no letters of credit outstanding under its credit facility as of December 31, 2016. For the years ended December 31, 2017, 2016 and 2015, EQM incurred commitment fees averaging approximately 20, 23 and 23 basis points, respectively, to maintain credit availability under its credit facility.

During 2017, 2016 and 2015, the maximum amounts of EQM's outstanding borrowings under the credit facility at any time were $260 million, $401 million and $404 million, respectively, the average daily balances were approximately $74 million, $77 million and $261 million, respectively, and interest was incurred at weighted average annual interest rates of 2.8%, 2.0% and 1.7%, respectively.

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 most significant covenants and events of default under the credit facility 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 $1 billion 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, 2017, EQM was in compliance with all debt provisions and covenants.

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

RMP $850 Million Facility

Rice Midstream OpCo LLC (RMP OpCo), a direct wholly owned subsidiary of RMP, has an $850 million, secured revolving credit facility that expires in December 2019. Subject to certain terms and conditions, the credit facility has an accordion feature that allows RMP OpCo to increase the available borrowings under the facility by up to an additional $200 million. Each lender in the facility may decide if it will increase its commitment. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions, to repurchase units and for general partnership purposes. The Company is not a guarantor of the obligations of RMP or any of its subsidiaries under the credit facility. The credit facility is secured by mortgages and other security interests on substantially all of RMP’s properties and is guaranteed by RMP and its restricted subsidiaries. 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 thereunder by RMP OpCo.

Under the terms of the RMP credit facility, RMP OpCo may obtain base rate loans or fixed period Eurodollar rate loans denominated in U.S. dollars. Base rate loans bear interest at a base rate plus a margin based on RMP's leverage ratio. Fixed period Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on the leverage ratio then in effect.

RMP is not required to maintain compensating bank balances under its credit facility. RMP’s leverage ratio in effect from time to time determines 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.

As of December 31, 2017, RMP OpCo had $286 million of borrowings and $1 million of letters of credit outstanding under the credit facility. The average daily outstanding balance of borrowings at any time under the credit facility during the period from November 13, 2017 to December 31, 2017 was approximately $268 million at a weighted average annual interest rate of 3.1%. RMP OpCo pays a commitment fee based on the undrawn commitment amount ranging from 37.5 to 50 basis points.

The credit facility contains various provisions that, if not complied with, could result in termination of the agreement, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the RMP credit facility relate to maintenance of certain financial ratios, as described below, limitations on certain investments and acquisitions, limitations on transactions with affiliates, limitations on restricted payments, limitations on the incurrence of additional indebtedness, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of and certain other defaults under other financial obligations and change of control provisions. The RMP credit facility requires RMP to maintain the following financial ratios: an interest coverage ratio of at least 2.50 to 1.0; a consolidated total leverage ratio of not more than 4.75 to 1.0, and after electing to issue senior unsecured notes, a consolidated total leverage ratio of not more than 5.25 to 1.0 (with certain increases for measurement periods following the completion of certain acquisitions); and if RMP elects to issue senior unsecured notes, a consolidated senior secured leverage ratio of not more than 3.50 to 1.0. As of December 31, 2017, RMP and RMP OpCo were in compliance with all credit facility provisions and covenants.

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15. Senior Notes

	December 31, 2017			December 31, 2016		
	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
6.50% Notes, due April 1, 2018	—	—	—	500,000	499,089	527,205
8.13% Notes, due June 1, 2019	700,000	698,918	755,153	700,000	698,106	789,271
Floating Rate Notes due October 1, 2020	500,000	497,206	501,325	—	—	—
2.50% Notes due October 1, 2020	500,000	497,169	497,670	—	—	—
4.88% Notes, due November 15, 2021	750,000	744,920	801,953	750,000	743,595	801,218
3.00% Notes due October 1, 2022	750,000	742,364	743,550	—	—	—
4.00% EQM Notes, due August 1, 2024	500,000	494,939	504,110	500,000	494,170	493,125
7.75% debentures, due July 15, 2026	115,000	110,732	135,024	115,000	110,235	141,800
4.125% EQM Notes, due December 1, 2026	500,000	492,413	501,990	500,000	491,562	488,460
3.90% Notes due October 1, 2027	1,250,000	1,238,707	1,245,200	—	—	—
Medium-term notes:						
7.42% Series B, due 2023	10,000	10,000	11,433	10,000	9,998	11,677
7.6% Series C, due 2018	8,000	7,999	8,012	8,000	7,991	8,375
8.7% to 9.0% Series A, due 2020 through 2021	35,200	35,187	40,510	35,200	35,168	41,906
	5,618,200	5,570,554	5,745,930	3,318,200	3,289,459	3,510,217
Less Senior Notes payable within one year	8,000	7,999	8,012	—	—	—
Total Senior Notes	$5,610,200	$5,562,555	$5,737,918	$3,318,200	$3,289,459	$3,510,217

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

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

On October 4, 2017, the Company completed the public offering (the 2017 Notes Offering) of $500 million aggregate principal amount of Floating Rate Notes due 2020 (the Floating Rate Notes), $500 million aggregate principal amount of 2.50% Senior Notes due 2020 (the 2020 Notes), $750 million aggregate principal amount of 3.00% Senior Notes due 2022 (the 2022 Notes) and $1,250 million aggregate principal amount of 3.90% Senior Notes due 2027 (the 2027 Notes, and, together with the Floating Rate Notes, the 2020 Notes and the 2022 Notes, the 2017 Notes). The Company received net proceeds from the 2017 Notes Offering of approximately $2,974.2 million, which the Company used, together with other cash on hand and borrowings under the Company's $2.5 billion credit facility, to fund the cash portion of the consideration for and expenses related to the Rice Merger and related transactions including the repayment of certain indebtedness of Rice and its subsidiaries, to redeem or repay $700 million of Company Senior Notes due in 2018 and for other general corporate purposes.

In October 2017, the Company delivered redemption notices to redeem all of its outstanding $200 million aggregate principal amount 5.15% Senior Notes due 2018 and $500 million aggregate principal amount 6.50% Senior Notes due 2018. On November 3, 2017, the Company redeemed the 5.15% Senior Notes due 2018 at a redemption price of 101.252%, plus accrued but unpaid interest, and the 6.50% Senior Notes due 2018 at a redemption price of 101.941%, plus accrued but unpaid interest. This resulted in make whole call premiums of $2.5 million and $9.7 million for the 5.15% Senior Notes due 2018 and the 6.50% Senior Notes due 2018, respectively. As a part of these transactions, the Company recorded loss on debt extinguishment of $12.6 million, which included the make whole call premiums and the write-off of $0.4 million in unamortized deferred financing costs.

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 Senior Notes are $8.0 million in 2018, $700.0 million in 2019, $1,011.2 million in 2020, $774.0 million in 2021, $750.0 million in 2022 and $2,375.0 million in 2023 and thereafter.

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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, 2017, 2016, and 2015:

	Year Ended December 31, 2017						
	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, 2016	$9,607		$(699)		$ (6,866)		$ 2,042
(Gains) losses reclassified from accumulated OCI, net of tax	(4,982)	(a)	144	(a)	338	(b)	(4,500)
Accumulated OCI (loss), net of tax, as of December 31, 2017	$4,625		$(555)		$ (6,528)		$ (2,458)

	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

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	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

(a) Gains (losses) reclassified from accumulated OCI, net of tax related to natural gas cash flow hedges were reclassified into operating revenues. Losses from accumulated OCI, net of tax related to interest rate cash flow hedges were reclassified into interest expense.

(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 1 for additional information.

17. Common Stock, Treasury Stock and Earnings Per Share

Common Stock

At December 31, 2017, shares of EQT's authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	20,457
Stock compensation plans	14,261
Total	34,718

In conjunction with the closing of the Rice Merger, the Company issued approximately 91 million shares of common stock on November 13, 2017.

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 10 and 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, 2017 and 2016, there were 253,145 and 226,288 shares of treasury stock in the rabbi trust, respectively. Shares of common stock held by the rabbi trust are treated 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,		
	2017	2016	2015
	(Thousands except per share amounts)		
Basic earnings per common share:			
Net income (loss) attributable to EQT Corporation	$1,508,529	$(452,983)	$85,171
Average common shares outstanding	187,380	166,978	152,398
Basic earnings (loss) per common share	$8.05	$(2.71)	$0.56
Diluted earnings per common share:			
Net income (loss) attributable to EQT Corporation	$1,508,529	$(452,983)	$85,171
Average common shares outstanding	187,380	166,978	152,398
Potentially dilutive securities:			
Stock options and awards (a)	347	—	541
Total	187,727	166,978	152,939
Diluted earnings (loss) per common share	$8.04	$(2.71)	$0.56

(a) Options to purchase common stock which were excluded from potentially dilutive securities because they were anti-dilutive totaled 429,785 shares and 291,700 shares for the years ended December 31, 2017 and 2015, respectively. 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.

The impact of EQM's, EQGP's, and RMP'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,		
	2017	2016	2015
	(millions)		
2013 Executive Performance Incentive Program	$—	$—	$6.8
2014 Executive Performance Incentive Program	—	9.5	12.9
2015 Executive Performance Incentive Program	5.4	12.4	12.1
2016 Incentive Performance Share Unit Program	13.1	7.2	—
2017 Incentive Performance Share Unit Program	5.0	—	—
2014 EQT Value Driver Award Program	—	—	1.1
2014 EQM Value Driver Award Program	—	—	0.6
2015 EQT Value Driver Award Program	—	3.2	14.6
2016 EQT Value Driver Performance Share Unit Award Program	3.4	15.7	—
2017 EQT Value Driver Performance Share Unit Award Program	10.8	—	—
Restricted stock awards	87.1	9.4	7.0
Non-qualified stock options	2.6	3.1	1.9
Other programs, including non-employee director awards	1.0	5.5	(2.3)
Total share-based compensation expense	$128.4	$66.0	$54.7

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 6. 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, 2017, 2016 and 2015 was $0.2 million, $5.0 million and $14.0 million, respectively. During the years ended December 31, 2017, 2016 and 2015, share-based payment arrangements paid in stock generated tax benefits of $58.9 million, $22.2 million and $43.1 million, respectively.

Executive Performance Incentive Programs - Equity & Liability

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

- the 2013 Executive Performance Incentive Plan (2013 Incentive PSU Program) under the 2009 Long-Term Incentive Plan (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);
- the 2016 Incentive Performance Share Unit Program (2016 Incentive PSU Program) under the 2014 LTIP; and
- the 2017 Incentive Performance Share Unit Program (2017 Incentive PSU Program) under the 2014 LTIP.

The 2013 Incentive PSU Program, the 2014 Incentive PSU Program, the 2015 Incentive PSU Program, the 2016 Incentive PSU Program and the 2017 Incentive PSU Program are collectively referred to as the Incentive PSU

Programs. All of the Incentive PSU Programs with the exception of the 2017 Incentive PSU Program (which granted both equity and liability awards) granted equity awards.

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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 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 recorded 2013 Incentive PSU Program, the 2014 Incentive PSU Program, the 2015 Incentive PSU Program, the 2016 Incentive PSU Program and the portion of the 2017 Incentive PSU Program to be settled in stock 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 2017 Incentive PSU Program also included awards to be settled in cash which are recorded at fair value as of the measurement date 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 for equity awards and two year risk free rate shown in chart below for liability awards. 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 2013 Incentive PSU Program and the cumulative total sales volume growth performance condition with respect to the other Incentive PSU Programs), the Monte Carlo simulation computed either the grant date fair value for equity awards or the measurement date fair value for liability awards for each possible performance condition outcome on the grant date for equity awards or the measurement date for liability awards. 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 or measurement date fair value, as applicable. 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	Settled In	Accounting Treatment	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, 2017[3]
2013	Stock	Equity	$140.00	0.36%	February 2016	261,073	$ 36.6	N/A	N/A
2014	Stock	Equity	$189.68	0.78%	February 2017	238,060	$ 45.2	N/A	N/A
2015	Stock	Equity	$141.11	1.10%	N/A	N/A	N/A	First Quarter of 2018	306,407
2016[4]	Stock	Equity	$96.30	1.31%	N/A	N/A	N/A	First Quarter of 2019	447,145
2017[5]	Stock	Equity	$120.60	1.47%	N/A	N/A	N/A	First Quarter of 2020	79,070
2017[6]	Cash	Liability	$103.70	1.88%	N/A	N/A	N/A	First Quarter of 2020	117,530

[1] Grant date fair value determined using a Monte Carlo simulation for equity awards. Fair value determined using a Monte Carlo simulation as of the measurement date for liability awards. For unvested Incentive PSU Programs the grant date fair value for equity awards and the measurement date fair value for liability awards is as of December 31, 2017. The Company recorded compensation expense as of December 31, 2017 using the grant date fair value for equity awards and the measurement date fair value for liability awards, each 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 subject to continued service through such date.
[3] Represents the number of outstanding units as of December 31, 2017 adjusted for forfeitures.
[4] As of January 1, 2017, a total of 482,030 units were outstanding under the 2016 Incentive PSU Program. Adjusting for 34,885 forfeitures, there were 447,145 outstanding units as of December 31, 2017.
[5] A total of 90,580 units were granted under the 2017 Incentive PSU Program - Equity in 2017 and no additional units may be granted. Adjusting for 11,510 forfeitures, there were 79,070 outstanding units as of December 31, 2017.
[6] A total of 133,000 units were granted under the 2017 Incentive PSU Program - Liability in 2017 and no additional units may be granted. Adjusting for 15,470 forfeitures, there were 117,530 outstanding units as of December 31, 2017.

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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) 2017	2016	2015
2013 Incentive PSU Program	$—	$ —	$4.4
2014 Incentive PSU Program	—	4.2	4.9
2015 Incentive PSU Program	2.2	4.9	4.9
2016 Incentive PSU Program	4.4	3.3	—
2017 Incentive PSU Program (liability only)	$1.7	$ —	$—

As of December 31, 2017, $12.9 million, $6.4 million and $7.9 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2016 Incentive PSU Program, the 2017 Incentive PSU Program - Equity and 2017 Incentive PSU Program - Liability, respectively, was expected to be recognized over the remainder of the performance periods.

The fair value is estimated using a Monte Carlo simulation valuation method with the following weighted average assumptions:

	For the Years Ended December 31, 2017 Liability[2]	2017 Equity	2016 Equity	2015 Equity	2014 Equity	2013 Equity
Risk-free rate	1.88 %	1.47 %	1.31 %	1.10 %	0.78 %	0.36 %
Dividend Yield[1]	N/A	N/A	N/A	N/A	N/A	N/A
Volatility factor	33.01 %	32.30 %	28.43 %	27.45 %	31.38 %	32.97 %
Expected term[2]	2 years	3 years	3 years	3 years	3 years	3 years

[1] Dividends paid from the beginning of the Performance Period will be cumulatively added as additional shares of common stock.
[2] Information shown for the valuation of the liability plan is as of measurement date.

Value Driver Award Programs

The Compensation Committee has also adopted:
- 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;
- the 2016 Value Driver Performance Share Unit Award Program (2016 EQT VDPSU Program) under the 2014 LTIP; and
- the 2017 Value Driver Performance Share Unit Award Program (2017 EQT VDPSU Program) under the 2014 LTIP.

The 2014 EQT VDPSU Program, the 2015 EQT VDPSU Program, the 2016 EQT VDPSU Program and the 2017 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 subject to continued service through such 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:

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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, 2017[2]
2014	Cash	Liability	$ 75.70	February 2015	$ 14.2	N/A	N/A
			$ 52.13	February 2016	$ 9.4		
2015	Stock	Equity	$ 75.70	February 2016	222,751	N/A	N/A
			$ 75.70	February 2017	208,567	N/A	N/A
2016[3]	Cash	Liability	$ 65.40	February 2017	$ 21.3	N/A	N/A
			$ 56.92	N/A	N/A	Second tranche first quarter of 2018	298,480
2017[4]	Cash	Liability	$ 56.92	N/A	N/A	First tranche first quarter of 2018	245,913
			N/A	N/A	N/A	Second tranche first quarter of 2019	246,297

[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, 2017, 651,328 awards including accrued dividends were outstanding under the 2016 EQT VDPSU Program.
[3] In addition to the $21.3 million in awards paid in February 2017, $0.2 million in awards were paid in 2017 in accordance with employee separation agreements.
[4] The total liability recorded for the 2017 EQT VDPSU Program was $21.0 million as of December 31, 2017.

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

	For the Years Ended December 31, (millions)		
Award	2017	2016	2015
2014 EQT VDPSU Program	$ —	$ —	$ 1.3
2015 EQT VDPSU Program	—	4.1	10.9
2016 EQT VDPSU Program	7.0	16.3	—
2017 EQT VDPSU Program	$ 10.3	$ —	$ —

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Restricted Stock Awards - Equity

The Company granted 85,350 and 158,360 restricted stock equity awards during the years ended December 31, 2017 and 2016, 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 through such date. 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 $63 and $75 for the years ended December 31, 2017 and 2016, 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 were fully vested at the end of the one-year period commencing on the date of grant. The fair value of this restricted stock grant, based on the Company's closing common stock price on the grant date, was $63.33 per share.

In conjunction with the closing of the Rice Merger, the Company converted Rice restricted stock equity awards and performance share equity awards to 2,290,234 Company restricted stock equity awards on November 13, 2017. Employees who were terminated on the closing date were immediately vested in their Company awards and received Merger Consideration cash of $5.30 per Rice share. Company awards of those employees who continued employment with the Company under a transition agreement will vest upon the earlier of (i) the end of the vesting period set forth in the original award agreement or (ii) the end of such employee's employment period set forth in his/her transition agreement, in both cases subject to continued service through such date. Company awards of those employees who continued employment with the Company on an at will basis will vest in accordance with the vesting period set forth in the original award agreement, assuming continued service through such date. The fair value of these restricted stock grants, based on the grant date fair value of the Company's common stock, was approximately $65.18 for the year December 31, 2017.

The total fair value of restricted stock awards vested during the years ended December 31, 2017, 2016 and 2015 was $123.0 million, $5.1 million and $3.8 million, respectively. The $123.0 million includes $13.0 million for the cash payment for the Merger Consideration of $5.30 per Rice share.

As of December 31, 2017, $11.7 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 year.

A summary of restricted stock equity award activity as of December 31, 2017, 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, 2017	224,340	$ 81.61	$ 18,309,538
Granted	2,375,584	65.12	154,690,670
Vested	(1,854,549)	66.31	(122,983,162)
Forfeited	(15,875)	78.12	(1,240,174)
Outstanding at December 31, 2017	729,500	$ 66.86	$ 48,776,872

Restricted Stock Unit Awards - Liability

The Company granted 292,400 and 148,860 restricted stock unit liability awards that will be paid in cash during the years ended December 31, 2017 and 2016 to key employees of the Company. Adjusting for forfeitures, there were 386,360 awards outstanding as of December 31, 2017. 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 through such date. The total liability recorded for these restricted units was $8.8 million and $2.7 million as of December 31, 2017 and 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, 2017, 2016 and 2015. 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,		
	2017 [1]	2016 [1]	2015
Risk-free interest rate	1.95 %	1.67 %	1.61 %
Dividend yield	0.18 %	0.16 %	0.12 %
Volatility factor	27.45 %	28.59 %	26.80 %
Expected term	5 years	5 years	5 years

	For the Years Ended December 31,		
	2017 [1]	2016 [1]	2015
Number of Options Granted	153,700	228,500	158,200
Weighted Average Grant Date Fair Value	$ 17.47	$ 15.10	$ 19.90
Total Intrinsic Value of Options Exercised (millions)	$ 1.7	$ 3.5	$ 15.1

[1] There were two grant dates for the 2017 and 2016 options. Amounts represent weighted average.

As of December 31, 2017, $2.5 million of unrecognized compensation cost related to outstanding nonvested stock options was expected to be recognized by December 31, 2019.

A summary of option activity as of December 31, 2017, 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, 2017	1,174,200	$ 60.99		
Granted	153,700	63.97		
Exercised	(158,700)	44.84		
Forfeited	(40,000)	67.91		
Expired	—	—		
Outstanding at December 31, 2017	1,129,200	$ 63.42	6.25 years	$ 1,428,439
Exercisable at December 31, 2017	691,100	$ 63.92	5.08 years	$ 668,266

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 in 2015.

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 217,414 non-employee director share-based awards including accrued dividends were outstanding as of December 31, 2017. A total of 26,090, 37,620 and 24,110 share-based awards were granted to non-employee directors during the years ended December 31, 2017, 2016 and 2015, 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 $65.35, $52.13 and $75.52 for the years ended December 31, 2017, 2016 and 2015, 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 21,740 independent director unit-based awards including accrued distributions were outstanding as of December 31, 2017. A total of 2,940, 2,610 and 2,220 unit-based awards were granted to independent directors during the years ended December 31, 2017, 2016 and 2015, 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 $76.68, $75.46 and $88.00 for the years ended December 31, 2017, 2016 and 2015, 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 21,014 independent director unit-based awards including accrued distributions were outstanding as of December 31, 2017. A total of 8,940, 8,270 and 2,910 unit-based awards were granted to independent directors during the years ended December 31, 2017, 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 $25.21, $21.57,

and $28.77 for the years ended December 31, 2017, 2016, and 2015 respectively.
The general partner of RMP has granted RMP common unit-based awards to certain of its independent directors, which vest one year from the date of grant, contingent upon continued service through such date. The Company records these awards as equity awards. A total of 20,688 independent director unit-based awards including accrued distributions were outstanding as of December 31, 2017. A total of 20,688 unit based awards were granted to independent directors during the year ended December 31, 2017. The fair value of these grants, based on RMP's closing common unit price on the business day prior to the grant date, was $24.41 for the year ended December 31, 2017. There have been no unit-based awards granted to independent directors since the Rice Merger.

2018 Value Driver Performance Share Unit Award Program and 2018 Incentive Performance Share Unit Program

Effective in 2018, the Compensation Committee adopted the 2018 EQT Value Driver Performance Share Unit Award Program (2018 EQT VDPSU Program) and the 2018 Incentive Performance Share Unit Program (2018 Incentive PSU Program)

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under the 2014 LTIP. The 2018 EQT VDPSU Program and 2018 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 363,460 units were granted under the 2018 EQT VDPSU Program. Fifty percent of the units confirmed under the 2018 EQT VDPSU will vest upon payment following the first anniversary of the grant date; the remaining 50% of the confirmed units under the 2018 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 2018 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, 2018 through December 31, 2018. If earned, the 2018 EQT VDPSU Program units are expected to be paid in cash.

A total of 314,210 units were granted under the 2018 Incentive PSU Program. The vesting of the units under the 2018 Incentive PSU Program will occur upon payment after December 31, 2020 (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, the level of operating and development cost improvement, and return on capital employed over the period January 1, 2018 through December 31, 2020. For certain key employees, the award will be reduced if the first year synergies in connection with the Rice Merger are not achieved. If earned, 172,350 of the 2018 Incentive PSU Program units are expected to be distributed in Company common stock and 141,860 of the 2018 Incentive PSU Program units are expected to be paid in cash.

2018 Stock Options

Effective January 1, 2018, the Compensation Committee granted 287,800 non-qualified stock options to key employees of the Company. The 2018 options are ten-year options, with an exercise price of $56.92, and are subject to three-year cliff vesting.

2018 Restricted Stock and Restricted Stock Unit Awards

Effective January 1, 2018, the Compensation Committee granted 86,200 restricted stock equity and 264,930 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 in markets available through the Company's current transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States. The Company also contracts with certain processors to market a portion of NGLs on behalf of the Company. Additionally, a significant amount of revenues and related accounts receivable from EQM Gathering, EQM Transmission and RMP Gathering 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 2017 and 2016. One customer within the EQT Production segment accounted for approximately 10% of the Company's total operating revenues in 2015.

Approximately 59% and 68% of the Company's accounts receivable balance as of December 31, 2017 and 2016, 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, 2017, 2016 or 2015.

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.

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As of December 31, 2017, 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, 2017, 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, 2017 totaled $16.4 billion (2018 - $652.7 million, 2019 - $1,022.2 million, 2020 - $1,007.5 million, 2021 - $1,004.2 million, 2022 - $1,000.5 million and thereafter - $11.7 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 $5.6 billion as of December 31, 2017.

The Company has agreements with drilling contractors to provide drilling equipment and services to the Company. These obligations totaled approximately $92.3 million as of December 31, 2017. Operating lease rentals for drilling contractors, office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately $60.8 million in 2017, $44.1 million in 2016 and $85.2 million in 2015. Future lease payments under non-cancelable operating leases as of December 31, 2017 totaled $231.5 million (2018 - $70.9 million, 2019 - $51.3 million, 2020 - $13.4 million, 2021 – $13.6 million, 2022 - $13.6 million and thereafter - $68.7 million).

RMP is party to a water system expansion and supply agreement with an affiliate of the Company and Southwestern Pennsylvania Water Authority (SPWA) pursuant to which the Company and RMP have agreed to jointly fund and assist SPWA in the construction and expansion of its water supply system serving parts of Greene, Fayette and Washington Counties in Pennsylvania. To date, RMP has executed authorizations for expenditures totaling approximately $29.5 million, and have funded approximately $9.7 million during the year ended 2017. In exchange for the Company and RMP's agreement to fund this construction and expansion, SPWA granted to the Company and RMP preferred rights to water volumes supplied through the system for use in the Company and RMP's oil and gas operations. Additionally, the Company and RMP are entitled to receive a surcharge assessed by SPWA against all oil and gas customers to whom water is supplied through the system in an amount equal to $3.50 per 1,000 gallons of water sold. All facilities and improvements constructed pursuant to the agreement are the property of SPWA.

Commencing in January 2017, the Company has commitments for frac sand to be used as a proppant in its hydraulic fracturing operations. Future commitments under these contracts as of December 31, 2017 totaled $30.6 million (2018 - $15.2 million and 2019 - $15.4 million).

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.

Prior to the Rice Merger, Rice entered into a Development Agreement and Area of Mutual Interest Agreement (collectively, the Utica Development Agreements) with the minority interest owner in Strike Force Midstream, covering approximately 50,000 aggregate net acres in the Utica Shale in Belmont County, Ohio. Pursuant to the Utica Development Agreements, the Company had approximately 68.7% participating interest in acreage currently owned or to be acquired by the Company or the minority interest owner in Strike Force Midstream located within Goshen and

Smith Townships (the Northern Contract Area) and an approximately 48.2% participating interest in acreage currently owned or to be acquired by the Company or the minority interest owner in Strike Force Midstream located within Wayne and Washington Townships (the Southern Contract Area), all within Belmont County, Ohio. The majority of the remaining participating interests are held by the minority interest owner in Strike Force Midstream. The participating interests of the Company and the minority interest owner in Strike Force Midstream in each of the Northern and Southern Contract Areas approximated the Company's then-current relative acreage positions in each area.

Pursuant to the Development Agreement, the Company is named the operator of drilling units located in the Northern Contract Area and the minority interest owner in Strike Force Midstream is named the operator of drilling units located in the Southern Contract Area. Upon development of a well on the subject acreage, the Company and the minority interest owner in Strike Force Midstream will convey to one another, pursuant to a cross conveyance, a working interest percentage equal to the amount of the underlying working interest multiplied by the applicable participating interest.

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The Utica Development Agreements have terms of 10 years and are terminable upon 90 days' notice by either party; provided that, with respect to interests included within a drilling unit, such interests shall remain subject to the applicable joint operating agreement and the Company and the minority interest owner in Strike Force Midstream shall remain operators of drilling units located in the Northern and Southern Contract Areas, respectively, following such termination.

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 $11.2 million is included in other liabilities and credits in the Consolidated Balance Sheets as of December 31, 2017.

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 $95 million as of December 31, 2017, extending at a decreasing amount for approximately 11 years.

See Note 12 for discussion of the MVP Joint Venture guarantee.

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22. Interim Financial Information (Unaudited)

The following quarterly summary of operating results reflects variations due primarily to the impact of Tax Reform Legislation in the three months ended December 31, 2017, 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. The summary also reflects the operations of Rice for the period of November 13, 2017 through December 31, 2017 due to the closing of the Rice Merger on November 13, 2017.

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(Thousands, except per share amounts)			
2017 (a)				
Total operating revenues	$897,523	$690,893	$ 660,313	$1,129,286
Operating income	390,644	189,794	137,694	214,849
Net income	250,705	122,645	105,457	1,379,335
Net income attributable to EQT Corporation	163,992	41,126	23,340	1,280,071
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
Net income	$0.95	$0.24	$ 0.13	$5.85
Diluted:				
Net income	$0.95	$0.24	$ 0.13	$5.83
2016 (a)				
Total operating revenues	$545,069	$127,531	$ 556,726	$379,022
Operating income	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)

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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,		
	2017	2016	2015
	(Thousands)		
At December 31:			
Capitalized Costs:			
Proved properties	$18,920,855	$12,179,833	$10,918,499
Unproved properties	5,016,299	1,698,826	898,270
Total capitalized costs	23,937,154	13,878,659	11,816,769
Accumulated depreciation and depletion	5,121,646	4,217,154	3,425,618
Net capitalized costs	$18,815,508	$9,661,505	$8,391,151

	For the Years Ended December 31,		
	2017	2016	2015
	(Thousands)		
Costs incurred: (a)			
Property acquisition:			
Proved properties (b)	$5,251,711	$403,314	$23,890
Unproved properties (c)	3,310,995	880,545	158,405
Exploration (d)	15,505	6,047	53,463
Development	1,365,615	777,787	1,633,498
Geological and geophysical	—	—	—

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

(b) Amounts in 2017 include $2,530.4 million and $1,192.0 million for the purchase of Marcellus wells and leases, respectively, acquired in the 2017 transactions discussed in Notes 2 and 10. The purchase of Marcellus leases includes measurement period adjustments to the 2016 acquisitions. Amounts in 2017 also include $1,228.6 million and $0.3 million for the purchase of Utica wells and leases, respectively, acquired in the 2017 transactions discussed in Notes 2 and 10. 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 10.

(c) Amounts in 2017 include $2,625.1 million and $0.5 million for the purchase of Marcellus leases and Utica leases, respectively, acquired in the 2017 transactions discussed in Notes 2 and 10. Amounts in 2016 include $770.4 million for the purchase of Marcellus leases acquired in the 2016 transactions discussed in Note 10.

(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 year ended December 31, 2017, EQT Production recorded no unproved property impairment. For the years ended December 31, 2016 and 2015, the Company recorded unproved property impairments of $6.9 million and $19.7 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 $7.6 million, $8.7 million and $37.4 million are included in exploration

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expense for the years ended December 31, 2017, 2016 and 2015, respectively. Unproved properties had a net book value of $5,016.3 million and $1,698.8 million at December 31, 2017 and 2016, respectively.

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,		
	2017	2016	2015
	(Thousands)		
Revenues:			
Nonaffiliated	$2,651,318	$1,594,997	$1,690,360
Production costs	1,338,069	1,055,017	877,194
Exploration costs	25,117	13,410	61,970
Depreciation, depletion and accretion	982,103	859,018	765,298
Impairment of long-lived assets	—	6,939	122,469
Amortization of intangible assets	5,540	—	—
Income tax expense (benefit)	117,984	(136,323)	(54,857)
Results of operations from producing activities (excluding corporate overhead)	$182,505	$(203,064)	$(81,714)

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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 Petroleum and Natural Gas Engineering from the Pennsylvania State University and has 29 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, 2017. Ryder Scott conducted a detailed, well by well, audit of the Company's largest properties. This audit covered 81% of the Company's proved developed reserves. Ryder Scott's audit of the remaining 19% of the Company's proved developed properties consisted of an audit of aggregated groups not exceeding 200 wells per case for operated wells and 256 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.

	Years Ended December 31,		
	2017	2016	2015
	(Millions of Cubic Feet)		
Total - Natural Gas, Oil, and NGLs (a)			
Proved developed and undeveloped reserves:			
Beginning of year	13,508,407	9,976,597	10,738,948
Revision of previous estimates	(2,766,981)	(472,285)	(2,194,675)
Purchase of hydrocarbons in place	9,389,638	2,395,776	—
Sale of hydrocarbons in place	(2,646)	—	(61)
Extensions, discoveries and other additions	2,225,141	2,384,682	2,051,071
Production	(907,892)	(776,363)	(618,686)
End of year	21,445,667	13,508,407	9,976,597
Proved developed reserves:			
Beginning of year	6,842,958	6,279,557	4,826,387
End of year	11,297,956	6,842,958	6,279,557
Proved undeveloped reserves:			
Beginning of year	6,665,449	3,697,040	5,912,561
End of year	10,147,711	6,665,449	3,697,040

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

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	Years Ended December 31,		
	2017	2016	2015
	(Millions of Cubic Feet)		
Natural Gas			
Proved developed and undeveloped reserves:			
Beginning of year	12,331,867	9,110,311	9,775,954
Revision of previous estimates	(2,760,467)	(607,171)	(2,059,531)
Purchase of natural gas in place	8,890,145	2,288,166	—
Sale of natural gas in place	(1,210)	—	(61)
Extensions, discoveries and other additions	2,164,578	2,241,528	1,955,935
Production	(794,677)	(700,967)	(561,986)
End of year	19,830,236	12,331,867	9,110,311
Proved developed reserves:			
Beginning of year	6,074,958	5,652,989	4,257,377
End of year	10,152,543	6,074,958	5,652,989
Proved undeveloped reserves:			
Beginning of year	6,256,909	3,457,322	5,518,577
End of year	9,677,693	6,256,909	3,457,322

	Years Ended December 31,		
	2017	2016	2015
	(Thousands of Bbls)		
Oil (a)			
Proved developed and undeveloped reserves:			
Beginning of year	6,395	5,900	5,005
Revision of previous estimates	5,103	1,159	1,219
Purchase of oil in place	355	3	—
Sale of oil in place	(139)	—	—
Extensions, discoveries and other additions	9	62	419
Production	(992)	(729)	(743)
End of year	10,731	6,395	5,900
Proved developed reserves:			
Beginning of year	6,395	5,900	5,005
End of year	10,731	6,395	5,900
Proved undeveloped reserves:			
Beginning of year	—	—	—
End of year	—	—	—

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

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	Years Ended December 31,		
	2017	2016	2015
	(Thousands of Bbls)		
NGLs (a)			
Proved developed and undeveloped reserves:			
Beginning of year	189,695	138,481	155,494
Revision of previous estimates	(6,189)	21,322	(23,743)
Purchase of NGLs in place	82,894	17,932	—
Sale of NGLs in place	(100)	—	—
Extensions, discoveries and other additions	10,084	23,797	15,437
Production	(17,877)	(11,837)	(8,707)
End of year	258,507	189,695	138,481
Proved developed reserves:			
Beginning of year	121,605	98,528	89,830
End of year	180,170	121,605	98,528
Proved undeveloped reserves:			
Beginning of year	68,090	39,953	65,664
End of year	78,337	68,090	39,953

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

2017 Changes in Reserves

- Transfer of 987 Bcfe of proved undeveloped reserves to proved developed reserves.
- Increase of 9,390 Bcfe associated with the acquisition of proved developed reserves (3,330 Bcfe) and proved undeveloped reserves (6,060 Bcfe) in the Company's Marcellus, Upper Devonian and Utica plays.
- Extensions, discoveries and other additions of 2,225 Bcfe, which exceeded the 2017 production of 908 Bcfe.
- Negative revisions of 3,522 Bcfe from proved undeveloped locations, primarily due to 3,074 Bcfe from locations that are no longer anticipated to be drilled within 5 years of booking as a result of acquiring new acreage. The acquired acreage presents opportunities to drill considerably longer laterals, realize operational efficiencies and improve overall returns.
- Upward revisions of 477 Bcfe from proved developed locations, primarily due to increased reserves from producing wells.
- Upward revisions of 278 Bcfe associated with previously booked locations whose economic lives had been extended due to improved commodity prices.

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.

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.

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- 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.

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, EQM and RMP. 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%. The estimated future net cash flows from natural gas and oil reserves as of December 31, 2017 includes the impact of the Tax Reform Legislation, which resulted in a lower federal income tax rate than the prior years presented.

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

	2017	2016	2015
	(Thousands)		
Future cash inflows (a)	$51,423,920	$24,011,281	$17,619,037
Future production costs	(18,379,892)	(14,864,126)	(10,963,285)
Future development costs	(5,637,676)	(3,778,698)	(2,377,650)
Future income tax expenses	(5,811,125)	(1,753,067)	(1,333,989)
Future net cash flow	21,595,227	3,615,390	2,944,113
10% annual discount for estimated timing of cash flows	(12,593,293)	(2,626,636)	(1,966,559)
Standardized measure of discounted future net cash flows	$9,001,934	$988,754	$977,554

(a) The majority of the Company's production is sold through liquid trading points on interstate pipelines. For 2017, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2017 of $51.34 per Bbl of oil (first day of each month closing price for West Texas Intermediate (WTI)) less regional adjustments, $2.801 per Dth for Columbia Gas Transmission Corp., $2.100 per Dth for Dominion Transmission, Inc., $2.914 per Dth for the East Tennessee Natural Gas Pipeline, $2.058 per Dth for Texas Eastern Transmission Corp., $1.995 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company, $2.321 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company, $2.665 per Dth for Waha, and $2.840 per Dth for the Rockies Express Pipeline Zone 3. For 2017, NGL pricing using arithmetic averages of the closing prices on the first day of each month during 2017 for NGL components and adjusted using the regional component makeup of produced NGLs resulted in prices of $23.07 per Bbl of NGLs from certain West Virginia Marcellus reserves, $31.11 per Bbl of NGLs from certain Kentucky reserves, $29.47 per Bbl for Ohio Utica reserves, and $27.93 per Bbl for Permian reserves.

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 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.

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, 2017 discounted future net cash flows before income taxes of the Company's proved reserves of approximately $1.8 billion, $50.4 million and $978.6 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:

	2017	2016	2015
	(Thousands)		
Sales and transfers of natural gas and oil produced – net	$(1,313,249)	$(539,980)	$(813,166)
Net changes in prices, production and development costs	2,236,183	(1,129,026)	(5,546,405)
Extensions, discoveries and improved recovery, less related costs	1,269,712	590,885	264,735
Development costs incurred	712,635	402,891	971,186
Purchase of minerals in place – net	5,357,921	592,078	—
Sale of minerals in place – net	(284)	—	(43)
Revisions of previous quantity estimates	(297,437)	(60,959)	(1,541,418)
Accretion of discount	115,437	122,674	600,099
Net change in income taxes	(1,477,603)	(91,823)	2,424,200
Timing and other (a)	1,409,865	124,460	(191,662)
Net increase (decrease)	8,013,180	11,200	(3,832,474)
Beginning of year	988,754	977,554	4,810,028
End of year	$9,001,934	$988,754	$977,554

(a) Increase in 2017 primarily driven by timing changes to the Company’s development plan as a result of the Rice Merger.

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.

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 (as such term is defined in Rule 13a-15(f) under the Exchange Act). 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, 2017. 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, 2017. Management's assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the Rice Merger on November 13, 2017. Rice's total assets and total operating revenues represented approximately 45% of the Company's consolidated total assets at December 31, 2017 and 10% of the Company's consolidated total operating revenues for the year ended December 31, 2017.

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.

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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.

Changes in Internal Control over Financial Reporting

As noted under “Management’s Report on Internal Control over Financial Reporting,” management’s assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the Rice Merger on November 13, 2017. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired company. The Company is in the process of integrating Rice’s and the Company’s internal controls over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. Except as noted above, there were no changes in the Company’s internal control over financial reporting that occurred during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Item 9B. Other Information

We intend to hold our 2018 annual meeting more than 30 days after the anniversary of our 2017 annual meeting. Accordingly, we have extended the deadline for receipt of shareholder proposals pursuant to Rule 14a-8 of the Exchange Act to February 28, 2018. The date of our annual meeting and the deadline for submitting director nominations and other proposals pursuant to our bylaws will be announced at a later time.

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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 2018 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2017:

- 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 15, 2018)," 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.

On November 13, 2017, the Company's articles of incorporation were amended and restated (as amended and restated, the Restated Articles of Incorporation) to increase the maximum number of directors permitted to be on the Board from twelve to fifteen. This amendment was approved by the Company's shareholders at a special meeting held on November 9, 2017.

Also on November 13, 2017, the Company's bylaws were amended and restated (as amended and restated, the Amended and Restated Bylaws) to conform to the Restated Articles of Incorporation by increasing the maximum number of directors permitted to be on the Board from twelve to fifteen.

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Item 11. Executive Compensation

The following information is incorporated herein by reference from the Company's definitive proxy statement relating to the 2018 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2017:

- 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 2018 annual meeting of shareholders, which will be filed with the SEC within 120 days after the close of the Company’s fiscal year ended December 31, 2017.

Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2017 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), the 2008 Employee Stock Purchase Plan (2008 ESPP), and the 2014 Rice Energy Inc. 2014 Long-Term Incentive Plan (Rice LTIP):

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]	3,835,415 [2]	$ 63.42 [3]	3,068,980 [4]
Equity Compensation Plans Not Approved by Shareholders [5]	89,891 [6]	N/A	4,872,501
Total	3,925,306	$ 63.42	7,941,481

(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) 520,100 shares subject to outstanding stock options under the 2014 LTIP; (ii) 2,569,766 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 856,589 target awards and dividend reinvestments thereon)); (iii) 76,532 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon; (iv) 628,800 shares subject to outstanding stock options under the 2009 LTIP; (v) 34,983 shares subject to outstanding directors’ deferred stock units under the 2009 LTIP, inclusive of dividend reinvestments thereon; and (vi) 5,234 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 6.25 years as of December 31, 2017.

(4) Consists of (i) 2,511,109 shares available for future issuance under the 2014 LTIP, (ii) 4,899 shares under the 2009 LTIP and (iii) 552,972 shares available for future issuance under the 2008 ESPP. As of December 31, 2017, 5,004 shares were subject to purchase under the 2008 ESPP.

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

(6) Consists of (i) 25,529 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, 2017; and (ii) 64,362 performance awards under the Rice LTIP, inclusive of dividend reinvestments thereon (based upon amounts previously confirmed in connection with the Rice Merger).

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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.

Rice Energy Inc. 2014 Long-Term Incentive Plan

The board of directors of Rice Energy adopted the Rice Energy Inc. 2014 Long-Term Incentive Plan (as amended and restated effective as of May 9, 2014), which was assumed by the Company in connection with the Rice Merger for employees and non-employee directors of the Company and any of its affiliates. The Company may issue long-term equity based awards under the plan. Employees and non-employee directors of the Company or any affiliate, including subsidiaries, are eligible to receive awards under the plan.

The aggregate number of shares that may be issued under the plan is 6,475,000 shares, subject to proportionate adjustment in the event of stock splits, recapitalizations, mergers and similar events. Shares subject to awards that (i) expire or are canceled, forfeited, exchanged, settled in cash, or otherwise terminated; and (ii) are delivered by the participant or withheld from an award to satisfy tax withholding requirements, and delivered or withheld to pay the exercise price of an option, will again be available for awards under the plan.

The plan is administered by the Committee, except to the extent the Board elects to administer the plan.

The plan authorizes the granting of awards in any of the following forms: performance awards, restricted stock units, dividend equivalent rights, market-priced options to purchase stock, stock appreciation rights, other stock-based awards that are denominated or payable in, valued in whole or in part by reference to, or otherwise based on stock, and cash-based awards.

The Board may amend, alter, suspend, discontinue or terminate the plan at any time, except that no amendment may be made without the approval of the Company’s shareholders if shareholder approval is required by any federal or state law or regulation or by the rules of any exchange on which the stock may then be listed, or if the amendment, alteration or other change increases the number of shares available under the plan, or if the Board in its discretion determines that obtaining such shareholder approval is for any reason advisable.

Shares to be delivered pursuant to awards under the plan may be shares made available from (i) authorized but unissued shares of stock, (ii) treasury stock, or (iii) previously issued shares of stock reacquired by the Company, including shares purchased on the open market.

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 2018 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2017.

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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. 3 – Ratification of Appointment of Independent Registered Public Accounting Firm” in the Company’s definitive proxy statement relating to the 2018 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of the Company’s fiscal year ended December 31, 2017.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report

1. All Financial Statements

2. Financial Statement Schedule

Schedule II - Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 2017

EQT CORPORATION AND SUBSIDIARIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2017

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:					
2017	$201,422	$70,063	$ —	$ (9,093)	$262,392
2016	$156,084	$24,706	$ 21,536	$ (904)	$201,422
2015	$64,987	$91,097	$ —	$ —	$156,084

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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3. Exhibits

Exhibits	Description	Method of Filing
2.01(a)	Agreement and Plan of Merger dated as of June 19, 2017 among the Company, Eagle Merger Sub I, Inc. and Rice Energy Inc.	Incorporated herein by reference to Exhibit 2.1 to Form 8-K (#001-3551) filed on June 19, 2017
2.01(b)	Amendment No. 1 to Agreement and Plan of Merger dated as of October 26, 2017 among the Company, Eagle Merger Sub I, Inc. and Rice Energy Inc.	Incorporated herein by reference to Exhibit 2.1 to Form 8-K (#001-3551) filed on October 26, 2017
2.02	Purchase and Sale Agreement dated as of September 26, 2016 among Vantage Energy Investment LLC, Vantage Energy Investment II LLC, Rice Energy Inc., Vantage Energy, LLC, and Vantage Energy II, LLC	Incorporated herein by reference to Exhibit 10.1 to Rice Energy Inc.'s Form 8-K (#001-36273) filed on September 30, 2016
3.01	Restated Articles of Incorporation of EQT Corporation (amended through November 13, 2017)	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on November 14, 2017
3.02	Amended and Restated Bylaws of EQT Corporation (amended through November 13, 2017)	Incorporated herein by reference to Exhibit 3.3 to Form 8-K (#001-3551) filed on November 14, 2017
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 (#001-3551) 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 (#001-3551) for the year ended December 31, 1998
4.01(c)	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 (#001-3551) for the year ended December 31, 1996
4.01(d)	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 (#001-3551) for the year ended December 31, 1997
4.01(e)	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	Incorporated herein by reference to Exhibit 4.01(i) to Form 10-K (#001-3551) for the year ended

	the Series C Medium-Term Notes	December 31, 1995
4.01(f)	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 (#001-3551) filed on July 1, 2008
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

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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Exhibits	Description	Method of Filing
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 (#001-3551) for the year ended December 31, 1996
4.02(c)	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 (#001-3551) 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 (#001-3551) filed on March 18, 2008
4.03(b)	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 (#001-3551) filed on May 15, 2009
4.03(c)	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 (#001-3551) filed on November 7, 2011
4.03(d)	Fifth Supplemental Indenture dated as of October 4, 2017 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the Floating Rate Notes due 2020 were issued	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on October 4, 2017
4.03(e)	Sixth Supplemental Indenture dated as of October 4, 2017 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 2.50% Senior Notes due 2020 were issued	Incorporated herein by reference to Exhibit 4.5 to Form 8-K (#001-3551) filed on October 4, 2017
4.03(f)	Seventh Supplemental Indenture dated as of October 4, 2017 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 3.00% Senior Notes due 2022 were issued	Incorporated herein by reference to Exhibit 4.7 to Form 8-K (#001-3551) filed on October 4, 2017

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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Exhibits	Description	Method of Filing
4.03(g)	Eighth Supplemental Indenture dated as of October 4, 2017 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 3.90% Senior Notes due 2027 were issued	Incorporated herein by reference to Exhibit 4.9 to Form 8-K (#001-3551) filed on October 4, 2017
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 (#001-3551) for the quarter ended September 30, 2014
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 (#001-3551) 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 (#001-3551) for the quarter ended June 30, 2012
* 10.01(b)	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 (#001-3551) for the year ended December 31, 2010
* 10.01(c)	Form of Amendment to Stock Option Award Agreements	Incorporated herein by reference to Exhibit 10.3 to Form 10-Q (#001-3551) for the quarter ended June 30, 2011
* 10.01(d)	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 (#001-3551) for the year ended December 31, 2011
* 10.01(e)	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 (#001-3551) for the year ended December 31, 2012

* 10.01(f)	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 (#001-3551) for the year ended December 31, 2012
* 10.01(g)	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 (#001-3551) 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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Exhibits	Description	Method of Filing
* 10.01(h)	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 (#001-3551) for the year ended December 31, 2013
* 10.01(i)	2014 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(w) to Form 10-K (#001-3551) for the year ended December 31, 2013
* 10.01(j)	Form of Participant Award Agreement under 2014 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(x) to Form 10-K (#001-3551) 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 (#001-3551) 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 (#001-3551) for the year ended December 31, 2014
* 10.02(c)	2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(d) to Form 10-K (#001-3551) for the year ended December 31, 2014
* 10.02(d)	Form of Participant Award Agreement under 2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(e) to Form 10-K (#001-3551) for the year ended December 31, 2014
* 10.02(e)	Amendment to 2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(f) to Form 10-K (#001-3551) for the year ended December 31, 2014
* 10.02(f)	Form of EQT 2015 Value Driver Performance Award Agreement	Incorporated herein by reference to Exhibit 10.9(c) to EQT Midstream Partners, LP's Form 10-K (#001-35574) for the year ended December 31, 2016
* 10.02(g)	2016 Incentive Performance Share Unit Program	Incorporated herein by reference to Exhibit 10.02(g) to Form 10-K (#001-3551) for the year ended December 31, 2015
* 10.02(h)	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 (#001-3551) for the year ended December 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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Exhibits	Description	Method of Filing
* 10.02(i)	2016 Restricted Stock Award Agreement (Standard) for Robert J. McNally	Incorporated herein by reference to Exhibit 10.03 to Form 10-Q (#001-3551) for the quarter ended March 31, 2016
* 10.02(j)	Form of EQT 2016 Value Driver Performance Award Agreement	Incorporated herein by reference to Exhibit 10.9(d) to EQT Midstream Partners, LP's Form 10-K (#001-35574) for the year ended December 31, 2016
* 10.02(k)	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 (#001-3551) for the year ended December 31, 2014
* 10.02(l)	2017 Incentive Performance Share Unit Program	Incorporated herein by reference to Exhibit 10.02(l) to Form 10-K (#001-3551) for the year ended December 31, 2016
* 10.02(m)	Form of Participant Award Agreement under 2017 Incentive Performance Share Unit Program	Incorporated herein by reference to Exhibit 10.02(m) to Form 10-K (#001-3551) for the year ended December 31, 2016
* 10.02(n)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (2017 grants)	Incorporated herein by reference to Exhibit 10.02(k) to Form 10-K (#001-3551) for the year ended December 31, 2016
* 10.02(o)	Form of EQT 2017 Value Driver Performance Award Agreement	Incorporated herein by reference to Exhibit 10.9(e) to EQT Midstream Partners, LP's Form 10-K (#001-35574) for the year ended December 31, 2016
* 10.02(p)	Form of EQT Restricted Stock Unit Award Agreement (Standard)	Incorporated herein by reference to Exhibit 10.9(a) to EQT Midstream Partners, LP's Form 10-K (#001-35574) for the year ended December 31, 2016
* 10.02(q)	Form of Restricted Stock Award Agreement under 2014 Long-Term Incentive Plan (pre-2018 grants)	Incorporated herein by reference to Exhibit 10.02(d) to Form 10-K (#001-3551) for the year ended December 31, 2016
* 10.02(r)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (2018 grants)	Filed herewith as Exhibit 10.02(r)
* 10.02(s)	Form of Restricted Stock Award Agreement under 2014 Long-Term Incentive Plan (2018 grants)	Filed herewith as Exhibit 10.02(s)
* 10.02(t)	2018 Incentive Performance Share Unit Program	Filed herewith as Exhibit 10.02(t)
* 10.02(u)		Filed herewith as Exhibit 10.02(u)

	Form of Participant Award Agreement under 2018 Incentive Performance Share Unit Program	
* 10.03(a)	Rice Energy Inc. 2014 Long-Term Incentive Plan (as amended and restated May 9, 2014)	Incorporated herein by reference to Exhibit 10.3 to Rice Energy Inc.'s Form 10-Q (#001-36273) for the quarter ended June 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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Exhibits	Description	Method of Filing
* 10.03(b)	Form of Restricted Stock Unit Agreement (Directors) for Rice Energy Inc.	Incorporated herein by reference to Exhibit 10.19 to Rice Energy Inc.'s Amendment No. 2 to Form S-1 Registration Statement (#333-192894) filed on January 8, 2014
* 10.04(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
* 10.04(b)	Form of EQT GP Holdings, LP Phantom Unit Award Agreement	Incorporated herein by reference to Exhibit 10.5 to EQT GP Holdings, LP's Amendment No. 1 to Form S-1 Registration Statement (#333-202053) filed on April 1, 2015
* 10.05	EQT Midstream Services, LLC 2012 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.03 to Form 10-K (#001-3551) for the year ended December 31, 2012
* 10.06	Rice Midstream Partners LP 2014 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 4.3 to Rice Midstream Partners LP's Form S-8 Registration Statement (#333-201169) filed on December 19, 2014
* 10.07(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 (#001-3551) for the year ended December 31, 2008
* 10.07(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 (#001-3551) for the year ended December 31, 2006
* 10.08	2016 Executive Short-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on April 21, 2016
* 10.09	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 (#001-3551) for the quarter ended June 30, 2015
* 10.10(a)	1999 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014)	Incorporated herein by reference to Exhibit 10.08 to Form 10-K (#001-3551) for the year ended December 31, 2014
* 10.10(b)	2005 Directors’ Deferred Compensation Plan (as amended and restated December 3, 2014)	Incorporated herein by reference to Exhibit 10.09 to Form 10-K (#001-3551) for the year ended December 31, 2014

* 10.11	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 (#001-3551) for the year ended December 31, 2008
10.12	Second Amended and Restated Credit Agreement dated as of July 31, 2017 among the Company, PNC Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer and the other lenders party thereto	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on August 3, 2017

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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Exhibits	Description	Method of Filing
* 10.13	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 (#001-3551) filed on July 31, 2015
* 10.14	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 (#001-3551) filed on July 31, 2015
* 10.15(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 (#001-3551) filed on March 17, 2016
* 10.15(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 (#001-3551) for the quarter ended March 31, 2016
* 10.16	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 (#001-3551) filed on July 31, 2015
* 10.17	Second Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of March 1, 2017 between the Company and David E. Schlosser, Jr.	Filed herewith as Exhibit 10.17
* 10.18(a)	Offer Letter dated as of July 26, 2017 between the Company and Jeremiah J. Ashcroft III	Filed herewith as Exhibit 10.18(a)
* 10.18(b)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of August 7, 2017 between the Company and Jeremiah J. Ashcroft III	Filed herewith as Exhibit 10.18(b)
* 10.19(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and M. Elise Hyland	Incorporated herein by reference to Exhibit 10.2 to EQT Midstream Partners, LP's Form 10-Q (#001-35574) for the quarter ended March 31, 2017
* 10.19(b)	Transition Agreement and General Release dated as of February 28, 2017 between the Company and M. Elise Hyland	Incorporated herein by reference to Exhibit 10.3 to EQT Midstream Partners, LP's Form 10-Q (#001-35574) for the quarter ended March 31, 2017
* 10.20(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 (#001-3551) filed on July 31, 2015
* 10.20(b)	Amendment to Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement	Incorporated herein by reference to Exhibit 10.12(b) to Form 10-K (#001-3551) for the

	effective as of January 1, 2016 between the Company and Randall L. Crawford	year ended December 31, 2015
* 10.20(c)	Transition Agreement and General Release dated as of January 9, 2017 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.14(e) to Form 10-K (#001-3551) for the year ended December 31, 2016
* 10.21	Separation and Release Agreement, dated as of November 13, 2017, among the Company, EQT RE, LLC and Daniel J. Rice IV	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on November 17, 2017

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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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.

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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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/ STEVEN T. SCHLOTTERBECK
Steven T. Schlotterbeck
President and Chief Executive Officer
February 15, 2018

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/ STEVEN T. SCHLOTTERBECK Steven T. Schlotterbeck (Principal Executive Officer)	President, Chief Executive Officer and Director	February 15, 2018
/s/ ROBERT J. MCNALLY Robert J. McNally (Principal Financial Officer)	Senior Vice President and Chief Financial Officer	February 15, 2018
/s/ JIMMI SUE SMITH Jimmi Sue Smith (Principal Accounting Officer)	Chief Accounting Officer	February 15, 2018
/s/ VICKY A. BAILEY Vicky A. Bailey	Director	February 15, 2018
/s/ PHILIP G. BEHRMAN Philip G. Behrman	Director	February 15, 2018
/s/ KENNETH M. BURKE Kenneth M. Burke	Director	February 15, 2018
/s/ A. BRAY CARY JR. A. Bray Cary, Jr.	Director	February 15, 2018
/s/ MARGARET K. DORMAN Margaret K. Dorman	Director	February 15, 2018
/s/ THOMAS F. KARAM Thomas F. Karam	Director	February 15, 2018
/s/ DAVID L. PORGES David L. Porges	Executive Chairman	February 15, 2018
/s/ DANIEL J. RICE IV Daniel J. Rice IV	Director	February 15, 2018

/s/ JAMES E. ROHR James E. Rohr	Director	February 15, 2018
/s/ NORMAN J. SZYDLOWSKI Norman J. Szydlowski	Director	February 15, 2018
/s/ STEPHEN A. THORINGTON Stephen A. Thorington	Director	February 15, 2018
/s/ LEE T. TODD, JR. Lee T. Todd, Jr.	Director	February 15, 2018
/s/ CHRISTINE J. TORETTI Christine J. Toretti	Director	February 15, 2018
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 15, 2018