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, 2015

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

or

FOR THE TRANSITION PERIOD FROM ___________ TO __________

COMMISSION FILE NUMBER 1-3551

EQT CORPORATION

(Exact name of registrant as specified in its charter)

PENNSYLVANIA	**25-0464690**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
625 Liberty Avenue **Pittsburgh, Pennsylvania**	**15222**
(Address of principal executive offices)	(Zip Code)

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer _X_	Accelerated filer ___
Non-accelerated filer ___	Smaller reporting company ___

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

The aggregate market value of voting stock held by non-affiliates of the registrant as of June 30, 2015: $10.5 billion

The number of shares (in thousands) of common stock outstanding as of January 31, 2016: 152,568

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the annual meeting of shareholders (to be held April 20, 2016) will be filed with the Commission within 120 days after the close of the Company's fiscal year ended December 31, 2015 and is incorporated by reference in Part III to the extent described therein.

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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.

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

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

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

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

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

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

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

margin call – a demand for additional margin deposits when forward prices move adversely to a derivative holder's position.

margin deposits – funds or good faith deposits posted during the trading life of a derivative contract to guarantee fulfillment of contract obligations.

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.

Glossary of Commonly Used Terms, Abbreviations and Measurements

NGL – natural gas liquids – 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 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).

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

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.

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.

Glossary of Commonly Used Terms, Abbreviations and Measurements

Abbreviations

ASC – Accounting Standards Codification
CBM – Coalbed Methane
CFTC – Commodity Futures Trading Commission
EPA – U.S. Environmental Protection Agency
FASB – Financial Accounting Standards Board
FERC – Federal Energy Regulatory Commission
GAAP - 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
WTI – West Texas Intermediate

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
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
Mbbl = thousand barrels
MMBtu = million British thermal units
MMcf = million cubic feet
MMcfe = million cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas
TBtu = trillion British thermal units
Tcfe = trillion cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas

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

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

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

PART I

Item 1. Business

General

EQT Corporation (EQT or the Company) conducts its business through two business segments: EQT Production and EQT Midstream. EQT Production is one of the largest natural gas producers in the Appalachian Basin with 10.0 Tcfe of proved natural gas, NGL and crude oil reserves across approximately 3.4 million gross acres, including approximately 630,000 gross acres in the Marcellus play, as of December 31, 2015. EQT Midstream provides gathering, transmission and storage services for the Company's produced gas, as well as for independent third parties across the Appalachian Basin, primarily through its ownership and control of EQT Midstream Partners, LP (EQM) (NYSE: EQM), a publicly traded limited partnership formed by EQT to own, operate, acquire and develop midstream assets in the Appalachian Basin.

In 2015, the Company formed EQT GP Holdings, LP (EQGP) (NYSE: EQGP), a Delaware limited partnership, to own the Company's partnership interests, including the incentive distribution rights, in EQM. As of December 31, 2015, the Company owned the entire non-economic general partner interest and 239,715,000 common units, which represented a 90.1% limited partner interest, in EQGP. As of December 31, 2015, EQGP owned the following EQM partnership interests, which represent EQGP's only cash-generating assets: 21,811,643 EQM common units, representing a 27.6% 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, or IDRs, which entitle EQGP to receive up to 48.0% of all incremental cash distributed in a quarter after $0.5250 has been distributed in respect of each common unit and general partner unit of EQM for that quarter. The Company is the ultimate parent company of EQGP and EQM.

Key Events in 2015

During 2015, EQT achieved record annual production sales volumes, including a 27% increase in total sales volumes and a 34% increase in Marcellus sales volumes. However, the average realized price to EQT Corporation for production sales volumes decreased 36% from $4.16 per Mcfe in 2014 to $2.67 per Mcfe in 2015. EQT's midstream business delivered record gathered volumes that were 28% higher than the previous year. During 2015, EQM reported net income of $393.5 million, $127.0 million higher than 2014. The increase was primarily related to higher operating income driven by production development in the Marcellus Shale by EQT and third parties. EQT and its consolidated subsidiaries also completed the following transactions and other events that were instrumental in contributing to a successful 2015:

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

- On March 10, 2015, the Company and certain subsidiaries of the Company entered into a contribution and sale agreement (Contribution Agreement) with EQM and EQM Gathering Opco, LLC (EQM Gathering), an indirect wholly owned subsidiary of EQM. Pursuant to the Contribution Agreement, on March 17, 2015, a subsidiary of the Company contributed the Northern West Virginia Marcellus gathering system to EQM Gathering in exchange for total consideration of $925.7 million, consisting of $873.2 million in cash, 511,973 EQM common units and 178,816 EQM general partner units (the NWV Gathering Transaction). EQM Gathering is consolidated by the Company as it is still controlled by the Company. On April 15, 2015, pursuant to the Contribution Agreement, the Company transferred a preferred interest in EQT Energy Supply, LLC, which at the time was an indirect wholly owned 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 17, 2015, EQM completed an underwritten public offering of 8,250,000 common units. On March 18, 2015, the underwriters exercised their option to purchase 1,237,500 additional common units on the same terms as the offering. EQM received net proceeds of $696.6 million from the offering after deducting the underwriters' discount and offering expenses of $24.5 million. EQM used the proceeds from the offering to fund a portion of the purchase price for the NWV Gathering Transaction.

- On March 30, 2015, the Company assigned 100% of the membership interests in MVP Holdco, LLC (MVP Holdco), an indirect wholly owned subsidiary of the Company that as of February 11, 2016 owned a 45.5% interest (the MVP Interest) in Mountain Valley Pipeline, LLC (MVP Joint Venture), to EQM for $54.2 million, which represented EQM's reimbursement to the Company for 100% of the capital contributions made by the Company to the MVP Joint Venture as of March 30, 2015. 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. The MVP Joint Venture submitted the MVP certificate application to the FERC in October 2015 and anticipates receiving the certificate in the fourth quarter of 2016. Subject to FERC approval, construction is scheduled to begin shortly thereafter and the pipeline is expected to be in-service during the fourth quarter of 2018.

- On May 15, 2015, EQGP completed an IPO of 26,450,000 common units, which represented 9.9% of EQGP's outstanding limited partner interests. EQT Gathering Holdings, LLC, an indirect wholly owned subsidiary of the Company, as the selling unitholder, sold all of the EQGP common units in the offering, resulting in net proceeds to the Company of approximately $674.0 million after deducting the underwriters' discount of approximately $37.5 million and structuring fees of approximately $2.7 million.

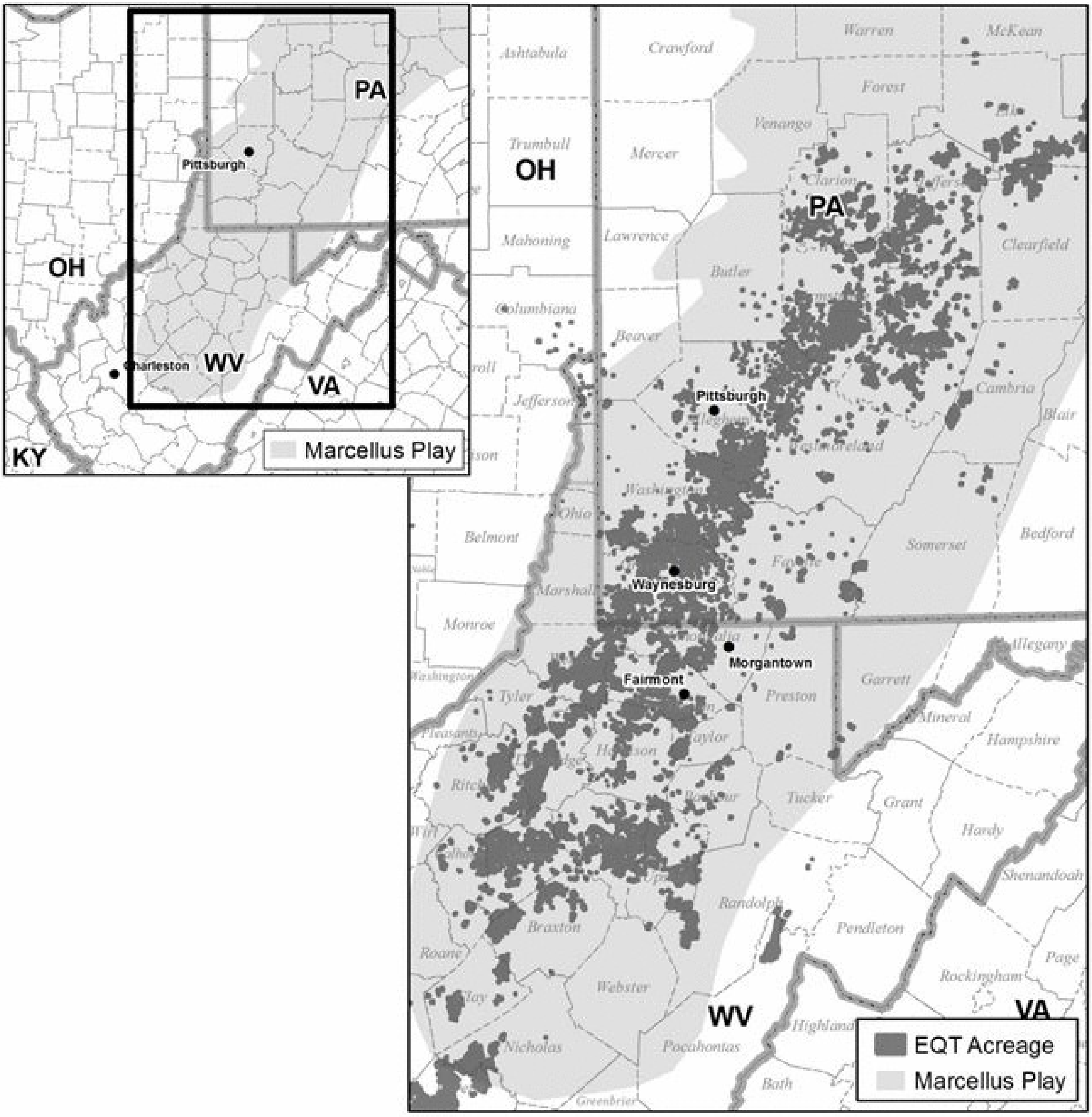
- During the second half of 2015, EQM entered into an equity distribution agreement that established an "At the Market" (ATM) common unit offering program, pursuant to which a group of managers, acting as EQM's sales agents, may sell EQM common units having an aggregate offering price of up to $750 million (the $750 million ATM Program). EQM issued 1,162,475 common units at an average price per unit of $74.92 during the six months ended December 31, 2015. EQM received net proceeds of approximately $85.5 million after deducting commissions of approximately $0.9 million and other offering expenses of approximately $0.7 million. EQM used the net proceeds from the sales for general partnership purposes.

- On November 16, 2015, EQM completed an underwritten public offering of 5,650,000 common units. EQM received net proceeds of $399.9 million from the offering after deducting the underwriters' discount and offering expenses of $5.7 million. EQM will use the net proceeds from the offering for general partnership purposes, including to fund a portion of EQM's anticipated 2016 capital expenditures related to transmission and gathering expansion projects and to repay amounts outstanding under EQM's credit facility.

EQT Production Business Segment

EQT Production is one of the largest natural gas producers in the Appalachian Basin with 10.0 Tcfe of proved natural gas, NGL and crude oil reserves across approximately 3.4 million gross acres, including approximately 630,000 gross acres in the Marcellus play, as of December 31, 2015. EQT believes that it is a technology leader in extended lateral horizontal and completion drilling 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 decreased 7% in 2015, primarily as a result of lower natural gas prices. The Company's Marcellus assets constitute approximately 7.8 Tcfe of the Company's total proved reserves.

The following illustration depicts EQT's acreage position within the Marcellus play as of December 31, 2015:



As of December 31, 2015, the Company's proved reserves were as follows:

(Bcfe)	Marcellus	Upper Devonian	Other	Total
Proved Developed	4,120	406	1,754	6,280
Proved Undeveloped	3,649	48	—	3,697
Total Proved Reserves	7,769	454	1,754	9,977

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 2015, the remaining reserve life of the Company's total proved reserves, as calculated by dividing total proved reserves by calendar year 2015 produced volumes, is 16 years.

The Company invested approximately $1,670 million on well development during 2015, with total production sales volumes hitting a record high of 603.1 Bcfe, an increase of 27% over the previous year. Capital spending for EQT Production is expected to be approximately $820 million in 2016 (excluding business development and land acquisitions), the majority of which will be used to support the drilling of approximately 77 gross wells, including 72 Marcellus wells and 5 deep Utica wells. During the past three years, the Company's number of wells drilled (spud) and related capital expenditures for well development were:

	Years Ended December 31,		
	2015	2014	2013
Gross wells spud:			
Horizontal Marcellus*	157	237	168
Other	4	108	57
Total	161	345	225
Capital expenditures for well development (in millions):			
Horizontal Marcellus*	$ 1,527	$ 1,456	$ 1,103
Other	143	261	134
Total	$ 1,670	$ 1,717	$ 1,237

* Includes Upper Devonian formations.

EQT Midstream Business Segment

The Company believes that the current footprint of its midstream assets, which are primarily owned by EQM and span a wide area of the Marcellus and Utica Shales in southwestern Pennsylvania and northern West Virginia, is a competitive advantage that uniquely positions the Company for growth. EQT Midstream is strategically positioned to capitalize on the increasing need for gathering and transmission infrastructure in the region, such as the need for midstream header connectivity to interstate pipelines in Pennsylvania and West Virginia.

In January 2012, the Company formed EQM, a publicly traded limited partnership, to own, operate, acquire and develop midstream assets in the Appalachian Basin. EQM provides midstream services to the Company and third parties through its two primary assets: EQM's transmission and storage system and EQM's gathering system.

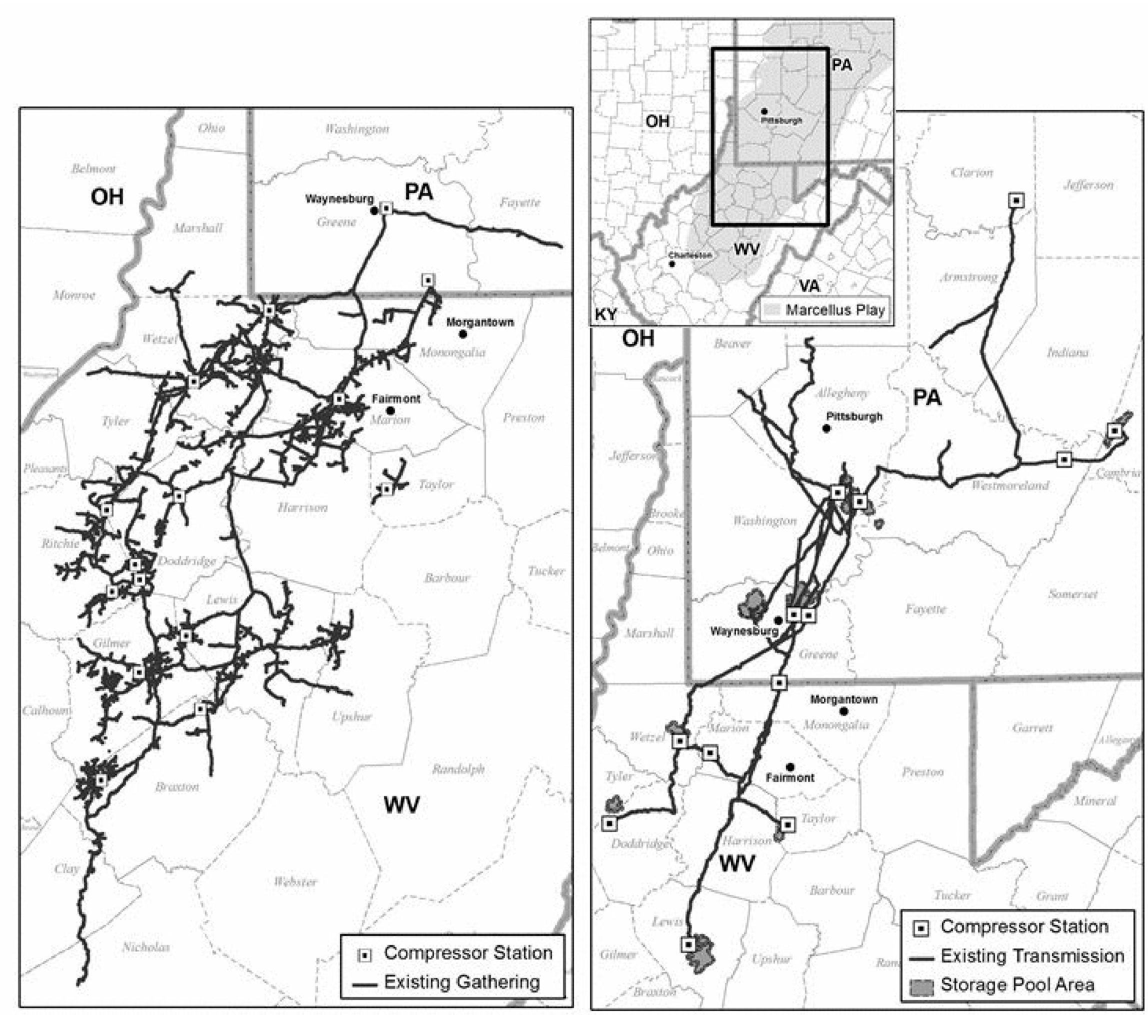
Due to the Company's ownership and control of EQGP and EQM, the results of EQGP and EQM are both consolidated in the Company's financial statements. Unless otherwise noted, discussions of EQT Midstream's business, operations and results in this Annual Report on Form 10-K include EQGP's and EQM's business, operations and results. The Company records the noncontrolling interests of the public limited partners of EQGP and EQM in its financial statements.

EQT Midstream's gathering system includes approximately 8,250 miles of gathering lines, including 1,500 miles of FERC-regulated, low pressure gathering lines owned by EQM and 185 miles of high pressure gathering lines not subject to federal rate regulation owned by EQM. The left-hand map on page 12 depicts the Company's gathering lines and compressor stations in relationship to the Marcellus Shale formation. As of December 31, 2015, the Company's Marcellus gathering capacity was approximately 2,000 MMcf per day, consisting of approximately 1,405 MMcf per day in Pennsylvania and approximately 595 MMcf per day in West Virginia.

EQT Midstream's transmission and storage system includes approximately 900 miles of FERC-regulated interstate pipeline that connects to seven interstate pipelines and multiple distribution companies. The interstate pipeline system includes approximately 700 miles of pipe owned by Equitrans, L.P. (Equitrans), an indirect wholly owned subsidiary of EQM. EQT Midstream's transmission and storage system also includes an approximately 200-mile pipeline referred to as the Allegheny Valley Connector (AVC), which was acquired by the Company in December 2013 in connection with the Equitable Gas Transaction (as described in Note 2 to the Consolidated Financial Statements).

The transmission and storage system is supported by eighteen natural gas storage reservoirs with approximately 660 MMcf per day of peak delivery capability and 47 Bcf of working gas capacity. Fourteen of these reservoirs, representing approximately 400 MMcf per day of peak delivery capability and 32 Bcf of working gas capacity, are owned by EQM. The storage reservoirs are clustered in two geographic areas connected to EQM's transmission and storage system, with ten in southwestern Pennsylvania and eight in northern West Virginia. The AVC facilities, which include four storage reservoirs, are owned by the Company and operated by EQM under a lease between EQM and an affiliate of the Company.

The right-hand map on page 12 depicts the Company's transmission lines, storage pools and compressor stations in relationship to the Marcellus Shale formation. EQT Midstream's year-end total transmission capacity was approximately 3,550 MMcf per day. EQT Midstream, primarily through EQM, began several multi-year transmission capacity expansion projects in 2015 to support the continued growth of the Marcellus and the developing deep Utica play, including the OVC which is currently under construction. EQM is also evaluating several projects that could total an additional 1.5 Bcf per day of capacity by year-end 2018. The projects may include additional compression, pipeline looping and new header pipelines.



EQT Midstream also has a gas marketing affiliate, EQT Energy, LLC (EQT Energy), that provides optimization of capacity and storage assets through its NGL and natural gas sales to marketers, utilities and industrial customers within EQT's operational footprint. EQT Energy also provides marketing services and manages approximately 1,740,000 Dth per day of third-party contractual pipeline capacity for the benefit of EQT Production; and has committed to an additional 520,000 Dth per day of third-party contractual capacity expected to come online in future periods. EQT Energy currently leases 3.7 Bcf of storage-related assets from third parties.

Strategy

EQT's strategy is to maximize shareholder value by maintaining an industry leading cost structure, and, despite a reduced capital budget in 2015 that is reflective of the current price environment, profitably developing its undeveloped reserves, and effectively and efficiently utilizing its extensive gathering and transmission assets that are uniquely positioned across the Marcellus and Utica Shales and in close proximity to the northeastern United States markets.

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

EQT also believes that its midstream assets are strategically located in the Marcellus and Utica Shale regions – spanning a large, prolific area of southwestern Pennsylvania and northern West Virginia – providing a competitive advantage that uniquely positions the Company for continued growth. EQT Midstream, primarily through EQM, intends to capitalize on the growing need for gathering and transmission infrastructure in this region, and in particular the need for midstream header connectivity to interstate pipelines in Pennsylvania and West Virginia. In order to meet this growing need, EQM has been focusing on a number of gathering and transmission projects, including the following:

- The OVC is a 37-mile pipeline that will extend EQM's transmission and storage system from northern West Virginia to Clarington, Ohio, at which point it will interconnect with the Rockies Express Pipeline and may interconnect with other pipelines and liquidity points. The OVC will provide approximately 850 BBtu per day of transmission capacity with an aggregate compression of approximately 38,000 horsepower. The Company has entered into a 20-year precedent agreement for a total of 650 BBtu per day of firm transmission capacity on the OVC. EQM received its FERC certificate to construct and operate the OVC on December 30, 2015 and construction began in January 2016. EQM expects the OVC to be in-service by year-end 2016.

- As of February 11, 2016, EQM owned a 45.5% interest in the MVP Joint Venture, which was formed to construct the MVP. The proposed pipeline is expected to be approximately 300 miles long, span from EQM's existing transmission and storage system in Wetzel County, West Virginia to Pittsylvania County, Virginia and be designed to transport natural gas production from the Marcellus and Utica Shale regions to the growing demand markets in the southeast region of the United States. The MVP Joint Venture submitted the MVP certificate application to the FERC in October 2015 and anticipates receiving the certificate in the fourth quarter of 2016. Subject to FERC approval, construction is scheduled to begin shortly thereafter and the pipeline is expected to be in-service during the fourth quarter of 2018.

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

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

Markets and Customers

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

The Company is also helping to build additional demand for natural gas. In mid-2011, EQT opened a public-access natural gas fueling station in Pittsburgh, Pennsylvania and, with the growing demand for compressed natural gas for numerous fleets throughout the region, the station underwent an expansion in 2013, adding two more dispensers. In conjunction with this project, the Company is promoting the use of natural gas with its own fleet vehicles and plans to operate 14% of its light-duty vehicle fleet, more than 175 vehicles, on natural gas by the end of 2016. In addition, all of the Company's contracted drilling rigs and completion crews utilize natural gas.

NGL Sales: The Company sells NGLs from its own production through the EQT Production segment and from gas marketed for third parties by EQT Midstream. In its Appalachian operations, the Company contracts with MarkWest Energy Partners, L.P. (MarkWest), a wholly owned subsidiary of MPLX LP, to process natural gas in order to extract heavier liquid hydrocarbons (propane, iso-butane, normal butane and natural gasoline) from the natural gas stream, primarily from EQT Production’s produced gas. NGLs are recovered at the processing plants and transported to a fractionation plant owned by MarkWest for separation into commercial components. MarkWest markets these components for a fee. The Company also has contractual processing arrangements in its Permian Basin operations whereby the Company sells gas to third-party processors at a weighted average liquids component price.

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

	2015	2014	2013
Average sales price per Mcfe sold (excluding cash settled derivatives)	$ 1.96	$ 4.14	$ 3.81
Average sales price per Mcfe sold (including cash settled derivatives)	$ 2.67	$ 4.16	$ 4.20

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

Natural Gas Gathering: EQT Midstream derives gathering revenues from charges to customers for use of its gathering system in the Appalachian Basin. The gathering system volumes are transported to four major interstate pipelines: Columbia Gas Transmission, East Tennessee Natural Gas Company, Dominion Transmission and Tennessee Gas Pipeline Company. The gathering system also maintains interconnections with EQM’s transmission and storage system.

Gathering system transportation volumes for 2015 totaled 754.3 TBtu, of which approximately 89% related to gathering for EQT Production and other affiliates. Revenues from EQT Production and other affiliates accounted for approximately 92% of 2015 gathering revenues.

Natural Gas Transmission and Storage: Natural gas transmission and storage operations are executed using transmission and underground storage facilities owned by the Company. Customers of EQT Midstream’s gas transmission and storage services are affiliates and third parties primarily in the northeastern United States.

As of December 31, 2015, the weighted average remaining contract life based on total projected contracted revenues for EQM’s firm transmission and storage contracts, including contracts on the AVC and contracts associated with expected future capacity from EQM expansion projects that are not yet fully constructed but for which EQM has entered into firm agreements, was approximately 17 years. In 2015, approximately 61% of transportation volumes and 53% of transmission revenues were from affiliates.

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

One customer within the EQT Production segment accounted for approximately 10%, 12% and 11% of EQT Production’s total operating revenues in 2015, 2014 and 2013, respectively. The Company does not believe that the loss of this customer would have a material adverse effect on its business because alternative customers for the Company’s natural gas are available.

Competition

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

Regulation

Regulation of the Company's Operations

EQT Production's exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances. These regulations and any delays in obtaining related authorizations may affect the costs and timing of developing the Company'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 integration of tracts to facilitate development and exploration. In West Virginia, the Company must rely on voluntary pooling of lands and leases for Marcellus and Upper Devonian acreage. In 2013, the Pennsylvania legislature enacted lease integration legislation, which authorizes joint development of existing contiguous leases, and Texas permits similar joint development. In addition, state conservation and oil and gas laws generally limit the venting or flaring of natural gas, and Texas sets production allowances on the amount of annual production permitted from a well.

EQT Midstream's transmission and gathering 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 interstate natural gas transmission systems and storage operations of EQT Midstream are regulated by the FERC, and certain gathering lines are also subject to rate regulation by the FERC. For instance, the FERC approves tariffs that establish EQM's rates, cost recovery mechanisms and other terms and conditions of service to EQM's customers. 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, the CFTC had adopted and implemented many final rules that impose regulatory obligations on all market participants, including the Company, such as recordkeeping and certain reporting obligations. Other CFTC rules that may be relevant to the Company have yet to be finalized. Because significant CFTC rules relevant to natural gas hedging activities are still at the proposal stage, it is not possible at this time to predict the extent of the impact of the regulations on the Company's hedging program or regulatory compliance obligations. The Company has experienced increased, and expects additional, compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

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

Environmental, Health and Safety Regulation

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

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

Vast quantities of natural gas deposits exist in shale and other formations. It is customary in the Company's industry to recover natural gas from these shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into a shale gas formation. These deeper formations are geologically separated and isolated from fresh ground water supplies by overlying rock layers. The Company's well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers. To assess water sources near our drilling locations, the Company conducts baseline and, as appropriate, post-drilling water testing at all water wells within at least 2,500 feet of our 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 19 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 1,914 employees at the end of 2015, and 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 the date they are filed with, or furnished to, the SEC. The filings are also available at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. These filings are also available on the internet at http://www.sec.gov.

Composition of Segment Operating Revenues

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

	For the Years Ended December 31,		
	2015	2014	2013
		(Thousands)	
Operating Revenues:			
Sales of natural gas, oil and NGLs (a)	$ 1,690,360	$ 2,132,409	$ 1,710,245
Pipeline and marketing services (b)	263,640	256,359	148,932
Gain on derivatives not designated as hedges (c)	385,762	80,942	2,834
Total operating revenues	$ 2,339,762	$ 2,469,710	$ 1,862,011

(a) Reported in EQT Production segment.

(b) Reported in EQT Midstream segment, with the exception of $28.5 million, $40.8 million and ($2.6) million for the years ended December 31, 2015, 2014 and 2013, respectively, which are reported within the EQT Production segment.

(c) Reported in EQT Production segment, with the exception of $0.7 million, ($2.8) million and $3.1 million for the years ended December 31, 2015, 2014 and 2013, respectively, which are reported within the EQT Midstream segment.

Financial Information about Segments

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

Jurisdiction and Year of Formation

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

Financial Information about Geographic Areas

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

Item 1A. Risk Factors

In addition to the other information contained in this 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, NGL and oil price volatility, or a prolonged period of low natural gas, NGL 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; the ability to export liquefied natural gas; the effect of energy conservation efforts; the price and availability of alternative fuels; the availability, proximity and capacity of pipelines, other transportation facilities, and gathering, processing and storage facilities; and government regulations, such as regulation of natural gas transportation and price controls. The market prices for natural gas, NGLs and oil were depressed throughout 2015 and the early part of 2016. The average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu from January 1, 2015 through February 10, 2016, and the average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $61.43 per barrel to a low of $26.55 per barrel during the same period. In addition, the market price for natural gas in the Appalachian Basin continues to be lower relative to NYMEX Henry Hub as a result of the significant increases in the supply of natural gas in the Northeast region in recent years. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas, including Appalachian basis, NGLs and oil and thus cannot predict the ultimate impact of prices on our operations. However, we do expect natural gas and NGL prices, particularly in the Appalachian Basin, to remain depressed during 2016.

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

Increases in natural gas, NGL 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, which is interest-bearing, provided to our hedge counterparties, 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.

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

Our business is subject to all of the inherent hazards and risks normally incidental to the operations for drilling, producing, transporting and storing natural gas, NGLs and oil, such as well site blowouts, cratering and explosions, pipe and other equipment and system failures, uncontrolled flows of natural gas or well fluids, fires, formations with abnormal pressures, 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 gas, NGLs and oil to market may adversely affect our earnings, cash flows and results of operations.

Our delivery of natural gas, NGLs and oil depends upon the availability, proximity and capacity of pipelines, other transportation facilities and gathering and processing facilities. The capacity of transmission, gathering and processing facilities may be insufficient to accommodate potential production from existing and new wells, which may result in substantial discounts in the prices we receive for our natural gas, NGLs and oil. Competition for pipeline infrastructure within the Appalachian Basin is intense, and many of our competitors have substantially greater financial resources than we do, which could affect our competitive position. The Company's investment in midstream infrastructure, primarily through EQM, is intended to address a lack of capacity on, and access to, existing gathering and transmission pipelines as well as curtailments on such pipelines. Our infrastructure development and maintenance programs can involve significant risks, including those related to timing, cost overruns and operational efficiency, and these risks can be affected by the availability of capital, materials and qualified contractors and work force, as well as weather conditions, natural gas, NGL and oil price volatility, delays in obtaining permits and other government approvals, title and property access problems, geology, 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, NGL and oil transmission, gathering, processing and storage facilities that are limited in number, geographically concentrated and subject to the same risks identified above with respect to our infrastructure development and maintenance programs. Because we do not own these third-party pipelines or facilities, their continuing operation is not within our control. An extended interruption of access to or service from our or third-party pipelines and facilities for any reason, including cyber-attacks on such pipelines and facilities or service interruptions due to gas quality, could result in adverse consequences to us, such as delays in producing and selling our natural gas, NGLs and oil. In such an event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at prices lower than market prices or at prices lower than we currently project. In addition, some of our third-party contracts involve significant long-term financial commitments on our part. Moreover, our usage of third parties for transmission, gathering and processing services subjects us to the credit and performance risk of such third parties and may make us dependent upon those third parties to get our produced natural gas, NGLs and oil to market.

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

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

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our 2016 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 2016 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, including the appropriate 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 2016 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; and our ability to achieve benefits anticipated to result from the transactions. In addition, various factors including prevailing market conditions could negatively impact the benefits we receive from transactions. Joint venture arrangements may restrict our operational and corporate flexibility. Moreover, joint venture arrangements involve various risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may have little control over, and our joint venture partners may not satisfy their obligations to the joint venture. Our inability to complete a transaction or to achieve our strategic or financial goals in any transaction could have significant adverse effects on our earnings, cash flows and financial position.

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

Our operations are regulated extensively at the federal, state and local levels. Laws, regulations and other legal requirements have increased the cost to plan, design, drill, install, operate and abandon wells, gathering and transmission systems and pipelines. Our exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of 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 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 or integration 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 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. 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 of up to $200,000 per day for each violation up to a maximum penalty of $2,000,000 for a related series of violations.

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

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

Recent discussions regarding the federal budget have included proposals that could potentially increase and accelerate the payment of federal and collaterally state income taxes of independent producers with the potential repeal of the ability to expense intangible drilling costs having the most significant potential future impact to us. These changes, if enacted, will make it more costly for us to explore for and develop our natural gas resources.

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

In 2010, the U.S. Congress adopted comprehensive financial reform legislation that 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 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, the CFTC had adopted and implemented many final rules that impose regulatory obligations on all market participants, including us, such as recordkeeping and certain reporting obligations. Other rules that may be relevant to us or our counterparties have yet to be finalized. Because significant rules relevant to natural gas hedging activities are still at the proposal stage, it is not possible at this time to predict the extent of the impact of the regulations on our hedging program, including available counterparties, or regulatory compliance obligations. We have experienced increased, and anticipate additional, compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

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

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

As of February 10, 2016, our long-term debt was rated “Baa3” by Moody’s Investors Services (Moody’s), “BBB” by Standard & Poor’s Ratings Service (S&P), and “BBB-” by Fitch Ratings Service (Fitch), and EQM's long-term debt was rated "Ba1" by Moody's, "BBB-" by S&P, and "BBB-" by Fitch. Although we are not aware of any current plans of Moody’s, S&P or Fitch to lower their respective ratings on our or EQM's debt, we cannot be assured that our or EQM's credit ratings will not be downgraded or withdrawn entirely by a rating agency. On December 16, 2015, Moody's announced that it had placed 29 U.S. exploration and production companies, including the Company, under review for a downgrade due to the low commodity price environment. On January 25, 2016, Moody’s also announced that it had placed three midstream partnerships, including EQM, under review for a downgrade primarily due to their affiliations with sponsoring exploration and production companies. Low prices for natural gas, NGLs and oil or an increase in the level of our indebtedness in the future may result in a downgrade in the ratings that are assigned to our or EQM's debt. If Moody’s or another credit rating agency downgrades the ratings, particularly below investment grade, our or EQM’s access to the capital markets may be limited, borrowing costs and margin deposits on our derivatives would increase, we may be required to provide additional credit assurances in support of pipeline capacity contracts, the amount of which may be substantial, or we or EQM may be required to provide additional credit assurances related to joint venture arrangements or construction contracts, which could adversely affect our business, results of operations and liquidity. Investment grade refers to the quality of a company's credit as assessed by one or more credit rating agencies. In order to be considered investment grade, the Company must be rated "BBB-" or higher by S&P, "Baa3" or higher by Moody's and "BBB-" or higher by Fitch.

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

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

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

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

Cyber incidents may adversely impact our operations.

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

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

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

We review the carrying values of our proved oil and gas properties generally on a field-by-field basis for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. The estimated future cash flows used to test 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 use of the asset, anticipated production from reserves, future market prices for natural gas, NGLs and oil, future operating costs and inflation. Commodity pricing is estimated by using a combination of the five-year NYMEX forward strip prices and assumptions related to gas quality, basis and inflation. Proved oil and gas properties 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 the five-year NYMEX forward strip prices during 2015, we recorded non-cash, pre-tax impairment charges of $94.3 million and $105.2 million to our proved oil and gas properties in the non-core Permian basin during 2015 and 2014, respectively. Further declines in natural gas, NGL 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 oil and gas properties, which may have a material adverse effect on our results of operations in future periods. See "Impairment of Oil and Gas Properties" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The amount and timing of actual future natural gas, NGL 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, NGL 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 will not be the same as the current market value of our estimated natural gas, NGL 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, NGL and oil industry in general.

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

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

EQT Production: EQT Production's properties are located primarily in Pennsylvania, West Virginia, Kentucky and Virginia. This segment has approximately 3.4 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. Approximately 630,000 of these gross acres are located in the Marcellus play. Although most of its wells are drilled to relatively shallow depths (2,000 to 8,000 feet below the surface), the Company retains what are normally considered "deep rights" on the majority of its acreage. As of December 31, 2015, the Company estimated its total proved reserves to be 10.0 Tcfe, consisting of proved developed producing reserves of 5.8 Tcfe, proved developed non-producing reserves of 0.5 Tcfe and proved undeveloped reserves of 3.7 Tcfe. Substantially all of the Company's reserves reside in continuous accumulations.

The Company's estimate of proved natural gas, NGL 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 Chemical Engineering from the Pennsylvania State University and has 18 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, NGL 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, NGL and oil proved reserves attributable to the Company's interests as of December 31, 2015. Ryder Scott conducted a detailed, well by well, audit of the Company's largest properties. This audit covered 80% of the Company's proved developed reserves. Ryder Scott's audit of the remaining approximately 20% of the Company's proved developed properties consisted of an audit of aggregated groups not exceeding 200 wells per case for operated wells and 230 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, NGL and crude oil reserves and future net cash flows is provided in Note 22 (unaudited) to the Consolidated Financial Statements.

In 2015, the Company commenced drilling operations (spud or drilled) on 157 gross horizontal wells with an aggregate of approximately 868,000 feet of pay in the Marcellus, including Upper Devonian, play. Total proved reserves in the Marcellus play decreased 6% to 7.8 Tcfe in 2015 primarily as a result of the Company's decision to reduce the scale of its five-year development plan and associated proved undeveloped reserves in response to a reduction in commodity prices. Total proved reserves in the Huron play decreased approximately 10% to 1.1 Tcfe due to the Company's decision to cease development in this play. Production sales volumes in 2015 from the Marcellus, including the Upper Devonian play, was 505.1 Bcfe. Over the past four years, the Company has experienced a 99% developmental drilling success rate.

Natural gas, NGLs and crude oil pricing:

	For the Years Ended December 31,		
	2015	2014	2013
Natural Gas:			
Average sales price (excluding cash settled derivatives) ($/Mcf)	$ 2.54	$ 4.51	$ 4.18
Average sales price (including cash settled derivatives) ($/Mcf)	$ 3.32	$ 4.53	$ 4.60
Average sales price (including cash settled derivatives and third-party gathering and transmission costs) ($/Mcf)	$ 2.79	$ 3.98	$ 4.00
NGLs:			
Average sales price including third-party processing costs ($/Bbl)	$ 7.15	$ 32.44	$ 36.80
Crude Oil:			
Average sales price ($/Bbl)	$ 38.70	$ 78.51	$ 85.82

NGLs and crude oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods.

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 2015, 2014 and 2013 was $0.12 per Mcfe, $0.14 per Mcfe and $0.15 per Mcfe, respectively. At December 31, 2015, the Company had approximately 50 multiple completion wells.

	Natural Gas	Oil
Total productive wells at December 31, 2015:		
Total gross productive wells	13,430	105
Total net productive wells	12,703	101
Total in-process wells at December 31, 2015:		
Total gross in-process wells	192	—
Total net in-process wells	191	—

Summary of proved natural gas, oil and NGL reserves as of December 31, 2015 based on average fiscal year prices:

	Natural Gas (MMcf)	Oil and NGLs (Bbls)
Developed	5,652,989	104,428
Undeveloped	3,457,322	39,953
Total proved reserves	9,110,311	144,381

Total acreage at December 31, 2015:	
Total gross productive acres	957,245
Total net productive acres	921,809
Total gross undeveloped acres	2,455,116
Total net undeveloped acres	2,220,336

As of December 31, 2015, the Company had no proved undeveloped reserves that remained undeveloped for more than five years.

Certain lease and acquisition agreements require the Company to drill a specific number of wells in 2016. Within the Marcellus formation, the Company is required to drill one well in 2016, which the Company intends to accomplish either directly through its 2016 development program or indirectly by contracting with a third party to do so, including through an assignment of the lease, farmout or other arrangement.

As of December 31, 2015, leases associated with approximately 34,147 gross undeveloped acres expire in 2016 if they are not renewed. This acreage is in addition to the acreage that may be lost if drilling obligations are not met. The Company has an active lease renewal program in areas targeted for development.

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

	For the Years Ended December 31,		
	2015	2014	2013
Exploratory wells:			
Productive	1	—	—
Dry	1	—	—
Development wells:			
Productive	234.5	265.4	138.4
Dry	3	—	2

Selected production, sales and acreage data by state (as of December 31, 2015 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 table on page 35 for sales volumes by final product.

	Pennsylvania	West Virginia	Kentucky	Other (b)	Total
Natural gas, oil and NGL production (MMcfe) – 2015 (a)	327,616	208,376	65,726	16,968	618,686
Natural gas, oil and NGL production (MMcfe) – 2014 (a)	237,365	164,330	66,775	19,609	488,079
Natural gas, oil and NGL production (MMcfe) – 2013 (a)	196,250	103,861	65,467	22,811	388,389
Natural gas, oil and NGL sales (MMcfe) – 2015	329,626	200,121	57,825	15,510	603,082
Natural gas, oil and NGL sales (MMcfe) – 2014	240,685	158,868	58,790	17,917	476,260
Natural gas, oil and NGL sales (MMcfe) – 2013	201,653	96,710	58,759	21,051	378,173
Average net revenue interest of proved reserves (%)	82.9%	85.5%	93.0%	79.4%	84.9%
Total gross productive wells	1,120	5,053	5,702	1,660	13,535
Total net productive wells	1,108	4,814	5,393	1,489	12,804
Total gross productive acreage	110,098	278,629	442,660	125,858	957,245
Total gross undeveloped acreage	297,782	875,496	1,062,317	219,521	2,455,116
Total gross acreage	407,880	1,154,125	1,504,977	345,379	3,412,361
Total net productive acreage	109,210	276,782	436,020	99,797	921,809
Total net undeveloped acreage	276,245	764,496	982,822	196,773	2,220,336
Total net acreage	385,455	1,041,278	1,418,842	296,570	3,142,145
(Amounts in Bcfe)					
Proved developed producing reserves	2,612	1,787	1,258	158	5,815
Proved developed non-producing reserves	256	209	—	—	465
Proved undeveloped reserves	2,205	1,492	—	—	3,697
Proved developed and undeveloped reserves	5,073	3,488	1,258	158	9,977
Gross proved undeveloped drilling locations	254	183	—	—	437
Net proved undeveloped drilling locations	244	183	—	—	427

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

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

The Company sells natural gas primarily within the Appalachian Basin 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, 2015, the Company's delivery commitments through 2020 were as follows:

For the Year Ended December 31,	Natural Gas (Bcf)
2016	634
2017	351
2018	230
2019	148
2020	91

Capital expenditures at EQT Production totaled $1,852 million during 2015, including $182 million for the acquisition of properties. The Company invested approximately $1,381 million during 2015 developing proved reserves and approximately $289 million on wells still in progress at year end. During the year ended December 31, 2015, the Company converted 1,527 Bcfe of proved undeveloped reserves to proved developed reserves. The Company had additions to proved developed reserves of 544 Bcfe, the majority of which were from wells spud that had not previously been classified as proved. Proved undeveloped reserves had negative revisions of 2,353 Bcfe in 2015 due primarily to the removal of uneconomic locations and the removal of locations that were no longer expected to be drilled within 5 years. This decrease was partially offset by the addition of 1,665 Bcfe of proved undeveloped reserves. These extensions and discoveries were mainly due to the addition of proved locations in the Company's Pennsylvania and West Virginia Marcellus play, along with 337 Bcfe attributed to lateral length extensions of proved undeveloped locations booked in 2014. As of December 31, 2015, the Company's proved undeveloped reserves totaled 3.7 Tcfe, 100% of which is associated with the development of the Marcellus, including Upper Devonian, play. All proved undeveloped drilling locations are expected to be drilled within five years.

The Company's 2015 extensions, discoveries and other additions totaled 2,051 Bcfe, which exceeded the 2015 production of 619 Bcfe. Of these reserves, 1,328 Bcfe are attributed to the addition of proved undeveloped locations in the Company's Pennsylvania and West Virginia Marcellus fields, 386 Bcfe are from the development of locations not previously booked as proved, and 337 Bcfe are due to the extension of lateral lengths associated with existing proved undeveloped locations.

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

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

EQT Midstream: EQT Midstream, which includes EQGP and EQM, owns or operates approximately 8,250 miles of gathering lines and 177 compressor units with approximately 255,000 horsepower of installed capacity, as well as other general property and equipment.

	Kentucky	West Virginia	Virginia	Pennsylvania	Total
Approximate miles of gathering lines	3,515	4,065	400	270	8,250

Substantially all of the gathering operation's sales volumes are delivered to several large interstate pipelines on which the Company and other customers lease capacity. These pipelines are subject to periodic curtailments for maintenance and repairs.

EQT Midstream also owns and operates a FERC-regulated transmission and storage system. These operations consist of an approximately 900-mile FERC-regulated interstate pipeline system that connects to seven interstate pipelines and multiple distribution companies. The system is supported by 18 associated natural gas storage reservoirs with approximately 660 MMcf per day of peak delivery capability and 47 Bcf of working gas capacity. The transmission and storage system stretches throughout northern West Virginia and southwestern Pennsylvania.

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

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

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

Item 3. Legal Proceedings

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

Environmental Proceedings

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. The Company was unable to resolve the PADEP claims due to the agency's interpretation of the penalty provisions of the Clean Streams Law. Accordingly, 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 legal interpretation. The Commonwealth Court upheld the PADEP's preliminary objections to the Company's complaint, and the Company appealed that decision to the Pennsylvania Supreme Court. On October 7, 2014, the PADEP filed a complaint against the Company before the Pennsylvania Environmental Hearing Board seeking $4.53 million in civil penalties. On December 29, 2015, the Pennsylvania Supreme Court reversed the Commonwealth Court and reinstated the Company's declaratory judgment in the Commonwealth Court. The Company believes the PADEP's penalty assessment is legally flawed and unsupportable under the Clean Streams Law. While the Company expects the PADEP's claims to result in penalties that exceed $100,000, the Company expects the resolution of these matters, individually and in the aggregate, will not have a material impact on the financial position, results of operations or liquidity of the Company.

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 areas in question. The Company disputes a number of the alleged NOVs and cannot predict with certainty whether any or all of these NOVs will result in penalties. If penalties are imposed, an individual penalty or the aggregate of these penalties could result in monetary sanctions in excess of $100,000.

Item 4. Mine Safety Disclosures

Not Applicable.

Executive Officers of the Registrant (as of February 11, 2016)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Theresa Z. Bone (52)	Vice President, Finance and Chief Accounting Officer (2007)	Elected to present position October 2013; Vice President and Corporate Controller from July 2007 to October 2013. Ms. Bone is also Vice President, Finance and Chief Accounting Officer of each of EQT Midstream Services, LLC, the general partner of EQM, since October 2013, and EQT GP Services, LLC, the general partner of EQGP, since January 2015. Ms. Bone was Vice President and Principal Accounting Officer of EQT Midstream Services, LLC from January 2012 to October 2013.
Philip P. Conti (56)	Senior Vice President and Chief Financial Officer (2000)	Elected to present position February 2007. Mr. Conti is also Senior Vice President, Chief Financial Officer and a Director of each of EQT Midstream Services, LLC, the general partner of EQM, since January 2012, and EQT GP Services, LLC, the general partner of EQGP, since January 2015. As previously disclosed in a Form 8-K filed with the SEC on August 10, 2015, Mr. Conti has advised the Company that he intends to retire at the end of 2016. The Company has retained an executive search firm to help identify his successor. Following the appointment of his successor, Mr. Conti is expected to continue to serve as an employee of the Company in some capacity through 2016 to ensure a smooth transition.
Randall L. Crawford (53)	Senior Vice President, EQT Corporation and President, Midstream and Commercial (2003)	Elected to present position December 2013; Senior Vice President, EQT Corporation and President, Midstream, Distribution and Commercial from April 2010 to December 2013. Mr. Crawford is also Executive Vice President, Chief Operating Officer and a Director of EQT Midstream Services, LLC, the general partner of EQM, since December 2013. Mr. Crawford was Executive Vice President and a Director of EQT Midstream Services, LLC from January 2012 to December 2013.
Lewis B. Gardner (58)	General Counsel and Vice President, External Affairs (2008)	Elected to present position March 2008. Mr. Gardner is also a Director of each of EQT Midstream Services, LLC, the general partner of EQM, since January 2012, and EQT GP Services, LLC, the general partner of EQGP, since January 2015.
Charlene Petrelli (55)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007.
David L. Porges (58)	Chairman and Chief Executive Officer (1998)	Elected to present position December 2015; Chairman, President, and Chief Executive Officer from May 2011 to December 2015; President, Chief Executive Officer and Director from April 2010 to May 2011. Mr. Porges is also Chairman, President and Chief Executive Officer of each of EQT Midstream Services, LLC, the general partner of EQM, since January 2012, and EQT GP Services, LLC, the general partner of EQGP, since January 2015.
Steven T. Schlotterbeck (50)	President, EQT Corporation and President, Exploration and Production (2008)	Elected to present position December 2015; Executive Vice President, EQT Corporation and President, Exploration and Production from December 2013 to December 2015; Senior Vice President, EQT Corporation and President, Exploration and Production from April 2010 to December 2013. Mr. Schlotterbeck is also a Director of EQT GP Services, LLC, the general partner of EQGP, since January 2015.

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.

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 2015 and 2014 are summarized as follows (in U.S. dollars per share):

	2015			2014		
	High	Low	Dividend	High	Low	Dividend
1st Quarter	$ 83.46	$ 71.33	$ 0.03	$ 104.72	$ 84.25	$ 0.03
2nd Quarter	92.79	80.86	0.03	111.47	95.78	0.03
3rd Quarter	81.67	63.09	0.03	107.71	89.77	0.03
4th Quarter	77.58	47.10	0.03	100.65	74.37	0.03

As of January 31, 2016, there were 2,508 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.

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, 2015:

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 2015 (October 1 – October 31)	—	$ —	—	700,000
November 2015 (November 1 – November 30)	8,203	63.49	—	700,000
December 2015 (December 1 – December 31)	3	57.35	—	700,000
Total	8,206	$ 63.49	—	

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

(b) During 2014, the Company's Board of Directors approved a share repurchase authorization of up to 1,000,000 shares of the Company's outstanding common stock. The Company may repurchase shares from time to time in open market or in privately negotiated transactions. The share repurchase authorization does not obligate the Company to acquire any specific number of shares, has no pre-established end date and may be discontinued by the Company at any time. As of December 31, 2015, the Company had repurchased 300,000 shares under this authorization since its inception.

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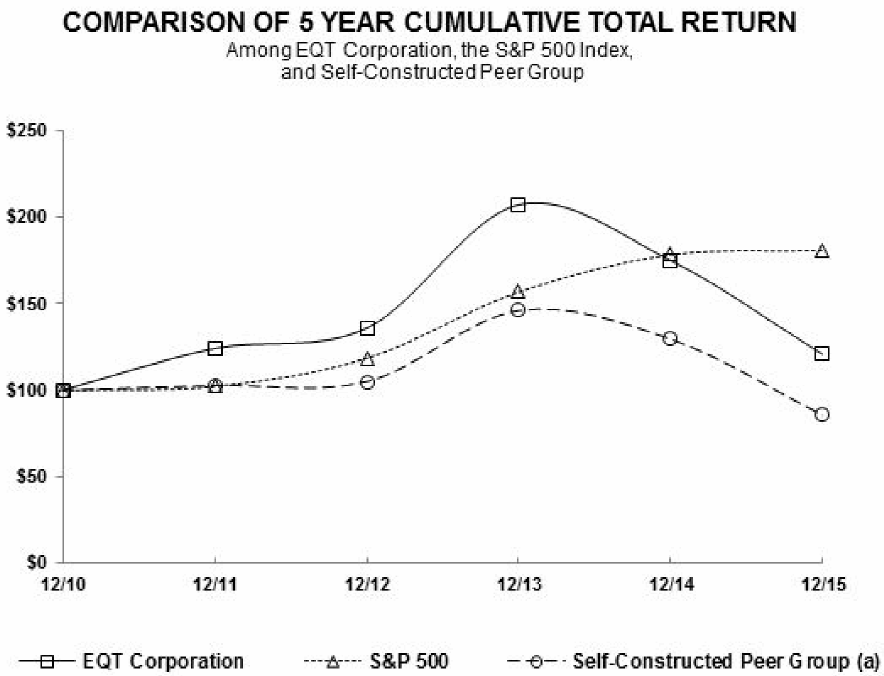
Stock Performance Graph

The following graph compares the most recent five-year cumulative total return attained by holders of the Company's common stock with the cumulative total returns of the S&P 500 Index and a customized peer group of the 25 companies listed in footnote (a) below (the Self-Constructed Peer Group). An investment of $100 (with reinvestment of all dividends) is assumed to have been made at the close of business on December 31, 2010 in the Company's common stock, in the S&P 500 Index and in the Self-Constructed Peer Group. Relative performance is tracked through December 31, 2015.



		12/10		12/11		12/12		12/13		12/14		12/15
EQT Corporation	**$**	**100.00**	**$**	**124.17**	**$**	**135.88**	**$**	**207.16**	**$**	**174.89**	**$**	**120.62**
S&P 500		**100.00**		**102.11**		**118.45**		**156.82**		**178.29**		**180.75**
Self-Constructed Peer Group (a)		**100.00**		**102.66**		**104.91**		**145.99**		**129.54**		**85.54**

(a) The Self-Constructed Peer Group includes the following 25 companies: Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Concho Resources, Inc., CONSOL Energy Inc., Continental Resources, Inc., Energen Corporation, EOG Resources, Inc., EXCO Resources, Inc., MarkWest Energy Partners, L.P., National Fuel Gas Company, Newfield Exploration Company, Noble Energy, Inc., ONEOK, Inc., Pioneer Natural Resources Company, QEP Resources, Inc., Questar Corporation, Quicksilver Resources Inc., Range Resources Corporation, SM Energy Company, Southwestern Energy Company, Spectra Energy Corp, Ultra Petroleum Corp., Whiting Petroleum Corporation and The Williams Companies, Inc. MarkWest Energy Partners, L.P. was acquired during 2015 and is included in the calculation from December 31, 2010 through December 31, 2014, at which time it was removed from the peer group calculation.

The Self-Constructed Peer Group is the same peer group used for the Company's 2015 Executive Performance Incentive Program, which utilizes three-year total shareholder return against the peer group as one performance metric.

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

Item 6. Selected Financial Data

	As of and for the Years Ended December 31,				
	2015	2014	2013	2012	2011
	(Thousands, except per share amounts)				
Total operating revenues	$ 2,339,762	$ 2,469,710	$ 1,862,011	$ 1,377,222	$ 1,323,829
Amounts attributable to EQT Corporation:					
Income from continuing operations	$ 85,171	$ 385,594	$ 298,729	$ 135,902	$ 419,582
Net income	$ 85,171	$ 386,965	$ 390,572	$ 183,395	$ 479,769
Earnings per share of common stock attributable to EQT Corporation:					
Basic:					
Income from continuing operations	$ 0.56	$ 2.54	$ 1.98	$ 0.91	$ 2.81
Net income	$ 0.56	$ 2.55	$ 2.59	$ 1.23	$ 3.21
Diluted:					
Income from continuing operations	$ 0.56	$ 2.53	$ 1.97	$ 0.90	$ 2.79
Net income	$ 0.56	$ 2.54	$ 2.57	$ 1.22	$ 3.19
Total assets	$ 13,976,172	$ 12,035,353	$ 9,765,907	$ 8,819,750	$ 8,741,610
Long-term debt	$ 2,793,343	$ 2,959,353	$ 2,475,370	$ 2,496,061	$ 2,715,833
Cash dividends declared per share of common stock	$ 0.12	$ 0.12	$ 0.12	$ 0.88	$ 0.88

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

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

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

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

Consolidated Results of Continuing Operations

2015 EQT Overview:

- Annual production sales volumes of 603.1 Bcfe, 27% higher than 2014
- Marcellus sales volumes of 505.1 Bcfe, 34% higher than 2014
- Gathered volumes of 754.3 TBtu, 28% higher than 2014
- The Company completed EQGP's IPO
- EQM completed two underwritten public offerings of common units representing limited partner interests

Income from continuing operations attributable to EQT Corporation for 2015 was $85.2 million, $0.56 per diluted share, compared with $385.6 million, $2.53 per diluted share, in 2014. The $300.4 million decrease in income from continuing operations attributable to EQT Corporation was primarily attributable to a 36% decrease in the average realized price to EQT Corporation for production sales volumes, higher operating expenses and higher net income attributable to noncontrolling interests of EQM and EQGP, partially offset by a 27% increase in production sales volumes, increased gains on derivatives not designated as hedges, increased gathering and transmission revenues and lower income tax expense. Operating expenses for 2015 and 2014 include $122.5 million and $267.3 million, respectively, of pre-tax, non-cash impairment charges related to the Company's oil and gas properties, which are included in the impairment of long-lived assets in the Statements of Consolidated Income.

The average realized price to EQT Corporation for production sales volumes was $2.67 per Mcfe for 2015 compared to $4.16 per Mcfe for 2014. The decrease in the average realized price was driven by lower NYMEX natural gas prices net of cash settled derivatives, lower NGL prices and a lower average differential, which includes Appalachian Basin basis, recoveries and cash settled basis swaps. Recoveries represent differences in natural gas prices between the Appalachian Basin and other markets reached by utilizing transportation capacity, differences in natural gas prices between Appalachian Basin and fixed price sales contracts, term sales with fixed differentials to NYMEX and other marketing activity, including capacity releases.

The Company's volume weighted average NYMEX natural gas index price was $2.66 per MMBtu for 2015, 39% lower than the average index price of $4.38 per MMBtu in 2014. In addition, the average differential decreased by $0.15 per Mcf, primarily due to lower Appalachian Basin basis. The Company's average NGL price was $18.84 per barrel for 2015, compared to $41.94 per barrel for 2014.

Operating income was $563.1 million in 2015 compared to $853.4 million in 2014, a decrease of $290.3 million. EQT Midstream's operating income increased by $89.1 million in 2015, primarily due to increases in gathering and transmission revenues as a result of production development in the Marcellus Shale, which was more than offset by a $401.1 million decrease in EQT Production's operating income in 2015. The average realized price to EQT Production decreased to $1.74 per Mcfe in 2015 compared to $3.23 per Mcfe in 2014. The decrease in the average realized price to EQT Production was offset by an increase in sales volumes of 27% primarily as a result of increased production from the 2014 and 2013 drilling programs in the Marcellus acreage, partially offset by the normal production decline in the Company’s producing wells. EQT Production total operating revenues for the year ended December 31, 2015 also included $385.1 million of derivative gains for derivative instruments not designated as hedging instruments compared to $83.8 million of derivative gains not designated as hedges and $24.8 million of gains for ineffectiveness of financial hedges for the year ended December 31, 2014. The increased derivative gains for the year ended December 31, 2015 primarily related to favorable changes in the fair market value of EQT Production's NYMEX swaps due to decreased forward NYMEX prices during the year ended December 31, 2015. EQT Production received $170.3 million and $36.5 million of net cash settlements for derivatives not designated as hedges for the years ended December 31, 2015 and 2014, respectively. These net cash settlements are included in the average realized price discussion.

Operating expenses for 2015 were $1,776.6 million compared to $1,650.5 million in 2014, an increase of $126.1 million. This increase was primarily attributable to higher depreciation, depletion, and amortization (DD&A) expense, higher transportation and processing expenses and higher exploration costs, partially offset by a favorable depletion rate and a decrease in the impairment of long-lived assets.

Income from continuing operations attributable to EQT Corporation for 2014 was $385.6 million, $2.53 per diluted share, compared with $298.7 million, $1.97 per diluted share, in 2013. The $86.9 million increase in income from continuing operations attributable to EQT Corporation was primarily attributable to a 26% increase in production sales volumes, favorable gains on derivatives not designated as hedges, increases in contracted transmission capacity and throughput and gathered volumes, favorable changes in hedging ineffectiveness, and lower interest expense. These factors were partially offset by impairments of long-lived assets, higher net income attributable to noncontrolling interests of EQM, higher transportation and processing expenses, higher income tax expense, higher selling, general and administrative (SG&A) expense and higher DD&A expense.

Operating income was $853.4 million in 2014 compared to $654.6 million in 2013, an increase of $198.8 million. EQT Production sales volumes increased 26% primarily as a result of increased production from the 2014 and 2013 drilling programs in the Marcellus acreage partially offset by the normal production decline in the Company's producing wells. The average realized price to EQT Production for sales volumes was $3.23 per Mcfe in 2014 compared to $3.15 per Mcfe in 2013. EQT Production total operating revenues for the year ended December 31, 2014 included $83.8 million of derivative gains for derivative instruments not designated as hedging instruments compared to $0.3 million of derivative losses for the year ended December 31, 2013. For the year ended December 31, 2014, EQT Production received $36.5 million of net cash settlements for derivatives not designated as hedges which is included in the average realized price to EQT Production of $3.23 per Mcfe in 2014. The year ended December 31, 2014 also included a $24.8 million gain for hedging ineffectiveness of financial hedges compared to a $21.3 million loss for ineffectiveness of financial hedges for the year ended December 31, 2013.

Transmission operating revenues increased in 2014 compared to 2013, reflecting continued production development in the Marcellus Shale by affiliate and third-party producers. The increase primarily resulted from higher firm transmission contracted capacity and throughput for third parties and EQT Production and higher interruptible transmission service. Gathering revenues increased primarily as a result of higher affiliate volumes gathered in 2014 compared to 2013, driven by production development in the Marcellus Shale. EQT Midstream significantly increased firm reservation fee revenues in 2014 compared to 2013 as a result of increased capacity under firm contracts with affiliates. The decrease in usage fees under interruptible contracts was primarily due to affiliates contracting for additional firm capacity.

Operating expenses for 2014 were $1,650.5 million compared to $1,227.0 million in 2013, an increase of $423.5 million. Excluding a $267.3 million impairment charge and $26.2 million increase in depreciation and depletion, operating expenses increased $130.0 million. This increase was primarily attributable to higher transportation and processing expenses and higher SG&A costs, consistent with the growth in the production and midstream businesses.

See "Other Income Statement Items" for a discussion of other income, interest expense, income taxes, income from discontinued operations and net income attributable to noncontrolling interests, and "Investing Activities" under the caption "Capital Resources and Liquidity" for a discussion of capital expenditures.

Consolidated Operational Data

Revenues earned by the Company from the sale of natural gas, NGLs and oil are split between EQT Production and EQT Midstream. The split is reflected in the calculation of EQT Production's average realized price. The following operational information presents detailed gross liquid and natural gas operational information as well as midstream deductions to assist in the understanding of the Company's consolidated operations.

The operational information in the table below presents an average realized price ($/Mcfe) to EQT Production and EQT Corporation, which is based on EQT Production adjusted net operating revenues, a non-GAAP supplemental financial measure. EQT Production adjusted net 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 net operating revenues should not be considered as an alternative to EQT Corporation total operating revenues as reported in the Statements of Consolidated Income, the most directly comparable GAAP financial measure. See "Reconciliation of Non-GAAP Measures" following that table for a reconciliation of EQT Production adjusted net operating revenues to EQT Corporation total operating revenues.

EQT Corporation

Price Reconciliation

in thousands (unless noted)	2015	2014	2013
	Years Ended December 31,		
LIQUIDS			
NGLs:			
Sales volume (MMcfe) (a)	51,530	40,587	27,860
Sales volume (Mbbls)	8,588	6,764	4,643
Gross price ($/Bbl)	$ 18.84	$ 41.94	$ 45.58
Gross NGL sales	$ 161,775	$ 283,728	$ 211,626
Third-party processing	(100,329)	(64,313)	(40,754)
Net NGL sales	$ 61,446	$ 219,415	$ 170,872
Oil:			
Sales volume (MMcfe) (a)	4,458	2,693	1,620
Sales volume (Mbbls)	743	449	270
Net price ($/Bbl)	$ 38.70	$ 78.51	$ 85.82
Net oil sales	$ 28,752	$ 35,232	$ 23,171
Net liquids sales	$ 90,198	$ 254,647	$ 194,043
NATURAL GAS			
Sales volume (MMcf)	547,094	432,980	348,693
NYMEX price ($/MMBtu) (b)	$ 2.66	$ 4.38	$ 3.67
Btu uplift	$ 0.25	$ 0.38	$ 0.30
Gross natural gas price ($/Mcf)	$ 2.91	$ 4.76	$ 3.97
Basis ($/Mcf)	(1.18)	(1.07)	(0.16)
Recoveries ($/Mcf) (c)	0.81	0.82	0.37
Cash settled basis swaps (not designated as hedges) ($/Mcf)	$ 0.03	$ 0.06	$ —
Average differential ($/Mcf)	$ (0.34)	$ (0.19)	$ 0.21
Average adjusted price ($/Mcf)	$ 2.57	$ 4.57	$ 4.18
Cash settled derivatives (cash flow hedges) ($/Mcf)	0.47	(0.06)	0.42
Cash settled derivatives (not designated as hedges) ($/Mcf)	0.28	0.02	—
Average adjusted price, including cash settled derivatives ($/Mcf)	$ 3.32	$ 4.53	$ 4.60
Net natural gas sales, including cash settled derivatives	$ 1,810,897	$ 1,962,667	$ 1,603,891
TOTAL PRODUCTION			
Total net natural gas & liquids sales, including cash settled derivatives	$ 1,901,095	$ 2,217,314	$ 1,797,934
Total sales volume (MMcfe)	603,082	476,260	378,173
Net natural gas & liquids price, including cash settled derivatives ($/Mcfe)	$ 3.15	$ 4.66	$ 4.75
Midstream Deductions ($/Mcfe)			
Gathering to EQT Midstream	$ (0.74)	$ (0.73)	$ (0.82)
Transmission to EQT Midstream	(0.19)	(0.20)	(0.23)
Third-party gathering and transmission costs	(0.48)	(0.50)	(0.55)
Total midstream deductions	$ (1.41)	$ (1.43)	$ (1.60)
Average realized price to EQT Production ($/Mcfe)	$ 1.74	$ 3.23	$ 3.15
Gathering and transmission to EQT Midstream ($/Mcfe)	$ 0.93	$ 0.93	$ 1.05
Average realized price to EQT Corporation ($/Mcfe)	$ 2.67	$ 4.16	$ 4.20

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

(b) The Company's volume weighted NYMEX natural gas price (actual average NYMEX natural gas price ($/MMBtu) was $2.66, $4.41 and $3.65 for the years ended December 31, 2015, 2014 and 2013, respectively).

(c) Recoveries represent differences in natural gas prices between the Appalachian Basin and other markets reached by utilizing transportation capacity, differences in natural gas prices between Appalachian Basin and fixed price sales contracts, term sales with fixed differentials to NYMEX and other marketing activity, including the sale of unused pipeline capacity. Recoveries include approximately $0.21, $0.19 and $0.23 per Mcf for the years ended December 31, 2015, 2014 and 2013, respectively, for the sale of unused pipeline capacity.

Reconciliation of Non-GAAP Measures

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

The Company reports gain (loss) for hedging ineffectiveness and gain (loss) on derivatives not designated as hedges within total operating revenues in the Statements of Consolidated Income.

EQT Production adjusted net operating revenues 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 net operating revenues as presented excludes the revenue impact of changes in the fair value of derivative instruments prior to settlement and is net of transportation and processing costs. Management utilizes EQT Production adjusted net operating revenues to evaluate earnings trends because the measure reflects only the impact of settled derivative contracts and thus does not burden the revenue from natural gas sales with the often volatile fluctuations in the fair value of derivatives prior to settlement. EQT Production adjusted net operating revenues also reflects transportation and processing costs as deductions from operating revenues because management considers the net price realized for sales of products, after the costs of processing and transporting the product to sales points, to be an indicator of the quality of earnings period-over-period. Management also considers this to be an indicator of how well the Company is utilizing its transportation and processing contracts. The sale price for natural gas is significantly impacted by the market in which the gas is sold and the expense incurred to transport and process the gas is important in evaluating the quality of earnings period-over-period because the cost of reaching a higher priced market may exceed the incremental price benefit of that market as compared to the market where the gas is produced. This is particularly important to natural gas producers in the Appalachian Basin given pipeline constraints and the impact on pricing in the area. Management further believes that EQT Production adjusted net operating revenues as presented provides useful information for investors for evaluating period-over-period earnings and is consistent with industry practices.

Calculation of EQT Production adjusted net operating revenues	**Years Ended December 31,**		
$ in thousands (unless noted)	**2015**	**2014**	**2013**
EQT Production total operating revenues, as reported on segment page	$ 1,540,889	$ 1,813,292	$ 1,310,938
(Deduct) add back:			
(Gain) loss for hedging ineffectiveness	—	(24,774)	21,335
(Gain) loss on derivatives not designated as hedges	(385,055)	(83,760)	301
Net cash settlements received on derivatives not designated as hedges	170,314	36,453	728
Premiums paid for derivatives that settled during the year	(364)	—	—
EQT Production transportation and processing, as reported on segment page	(274,379)	(200,562)	(142,281)
EQT Production adjusted net operating revenues, a non-GAAP measure	$ 1,051,405	$ 1,540,649	$ 1,191,021
Total sales volumes (MMcfe)	603,082	476,260	378,173
Average realized price to EQT Production ($/Mcfe)	$ 1.74	$ 3.23	$ 3.15
Add:			
Gathering and Transmission to EQT Midstream ($/Mcfe)	$ 0.93	$ 0.93	$ 1.05
Average realized price to EQT Corporation ($/Mcfe)	$ 2.67	$ 4.16	$ 4.20
EQT Production total operating revenues, as reported on segment page	$ 1,540,889	$ 1,813,292	$ 1,310,938
EQT Midstream total operating revenues, as reported on segment page	807,904	699,083	614,042
Less: intersegment revenues, net	(9,031)	(42,665)	(62,969)
EQT Corporation total operating revenues, as reported in accordance with GAAP	$ 2,339,762	$ 2,469,710	$ 1,862,011

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, administrative costs and for 2013, corporate overhead charges previously allocated to the Company's Distribution segment that were reclassified to headquarters as part of the recast of those periods to reflect the discontinued operations presentation.

The Company has reported the components of each segment's operating income from continuing operations and various operational measures in the sections below, and where appropriate, has provided information describing how a measure was derived. EQT's management believes that presentation of this information provides useful information to management and investors regarding the financial condition, operations and trends of each of EQT's business segments without being obscured by the financial condition, operations and trends for the other segment or by the effects of corporate allocations of interest, income taxes and other income. In addition, management uses these measures for budget planning purposes. Purchased gas costs at EQT Midstream include natural gas purchases, including natural gas purchases from affiliates, purchased gas costs adjustments and other gas supply expenses. These purchased gas costs are primarily attributable to transactions with affiliates and are eliminated in consolidation. Consistent with the consolidated results, energy trading contracts recorded within storage, marketing and other revenues are reported net within operating revenues, regardless of whether the contracts are physically or financially settled. The Company has reconciled each segment's operating income to the Company's consolidated operating income and net income in Note 5 to the Consolidated Financial Statements.

EQT Production

Results of Operations

	Years Ended December 31,				
	2015	2014	% change 2015 - 2014	2013	% change 2014 - 2013
OPERATIONAL DATA					
Sales volume detail (MMcfe):					
Marcellus (a)	505,102	378,195	33.6	275,029	37.5
Other (b)	97,980	98,065	(0.1)	103,144	(4.9)
Total production sales volumes (c)	603,082	476,260	26.6	378,173	25.9
Average daily sales volumes (MMcfe/d)	1,652	1,305	26.6	1,036	26.0
Average realized price to EQT Production ($/Mcfe)	$ 1.74	$ 3.23	(46.1)	$ 3.15	2.5
Lease operating expenses (LOE), excluding production taxes ($/Mcfe)	$ 0.12	$ 0.14	(14.3)	$ 0.15	(6.7)
Production taxes ($/Mcfe)	$ 0.09	$ 0.14	(35.7)	$ 0.13	7.7
Production depletion ($/Mcfe)	$ 1.18	$ 1.22	(3.3)	$ 1.50	(18.7)
DD&A (thousands):					
Production depletion	$ 713,651	$ 582,624	22.5	$ 568,990	2.4
Other DD&A	9,797	10,231	(4.2)	9,651	6.0
Total DD&A	$ 723,448	$ 592,855	22.0	$ 578,641	2.5
Capital expenditures (thousands) (d)	$ 1,852,100	$ 2,441,486	(24.1)	$ 1,423,185	71.6
FINANCIAL DATA (thousands)					
Revenues:					
Production sales	$ 1,155,834	$ 1,704,758	(32.2)	$ 1,332,574	27.9
Gain (loss) for hedging ineffectiveness	—	24,774	(100.0)	(21,335)	(216.1)
Gain (loss) on derivatives not designated as hedges	385,055	83,760	359.7	(301)	(27,927.2)
Total operating revenues	1,540,889	1,813,292	(15.0)	1,310,938	38.3
Operating expenses:					
Transportation and processing	274,379	200,562	36.8	142,281	41.0
LOE, excluding production taxes	70,556	65,917	7.0	57,110	15.4
Production taxes	53,109	67,571	(21.4)	50,981	32.5
Exploration expense	61,970	21,665	186.0	18,483	17.2
SG&A	134,294	118,816	13.0	92,197	28.9
DD&A	723,448	592,855	22.0	578,641	2.5
Impairment of long-lived assets	118,268	267,339	(55.8)	—	100.0
Total operating expenses	1,436,024	1,334,725	7.6	939,693	42.0
Gain on sale / exchange of assets	—	27,383	(100.0)	—	100.0
Operating income	$ 104,865	$ 505,950	(79.3)	$ 371,245	36.3

(a) Includes Upper Devonian wells.

(b) Includes 4,173 MMcfe of deep Utica sales volume for the year ended December 31, 2015.

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

(d) Includes $167.3 million of cash capital expenditures and $349.2 million of non-cash capital expenditures for the exchange of assets with Range Resources Corporation (Range) during the year ended December 31, 2014 and $114.2 million of cash capital expenditures for the purchase of acreage and Marcellus wells from Chesapeake Energy Corporation and its partners (Chesapeake) during the year ended December 31, 2013.

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

EQT Production's operating income totaled $104.9 million for 2015 compared to $506.0 million for 2014. The $401.1 million decrease in operating income was primarily due to a lower average realized price to EQT Production and increased operating expenses partially offset by increased sales of produced natural gas and increased gains on derivatives not designated as hedges. Operating expenses included non-cash impairment charges of $118.3 million in 2015 and $267.3 million in 2014. The 2015 impairment charge consisted of impairments of proved properties in the Permian Basin of Texas of $94.3 million and impairments of proved properties in the Utica Shale of Ohio of $4.3 million, as well as $19.7 million for unproved property impairments of non-core Marcellus acreage related to lease expirations. The 2014 impairment charge consisted of impairments of proved properties in the Permian Basin of Texas of $105.2 million and impairments of proved properties in the Utica Shale of Ohio of $75.5 million, as well as impairments of $86.6 million associated with undeveloped properties. The proved properties impairments in 2015 and 2014 were a result of continued declines in commodity prices and insufficient recovery of hydrocarbons to support continued development. The 2015 and 2014 impairments related to the unproved properties were due to operational decisions to focus near-term development activities in the Company's core Marcellus and deep Utica acreage.

Total operating revenues were $1,540.9 million for 2015 compared to $1,813.3 million for 2014. The $272.4 million decrease in total operating revenues was primarily due to a 46% decrease in the average realized price to EQT Production and a prior year gain on hedge ineffectiveness, partly offset by a 27% increase in production sales volumes and increased gains on derivatives not designated as hedges in 2015.

The $1.49 per Mcfe decrease in the average realized price to EQT Production for the year ended December 31, 2015 was primarily due to the decrease in the average NYMEX natural gas price net of cash settled derivatives of $1.06 per Mcf, lower NGL prices and a decrease in the average natural gas differential of $0.15 per Mcf. The average differential for 2015 includes lower Appalachian Basin basis of $0.11 per Mcf. Recoveries per Mcf (also included in the average differential) for the year ended December 31, 2015 were consistent with the year ended December 31, 2014. Recoveries represent differences in natural gas prices between the Appalachian Basin and other markets reached by utilizing transportation capacity, differences in natural gas prices between Appalachian Basin and fixed price sales contracts, term sales with fixed differentials to NYMEX and other marketing activity, including capacity releases. Favorable recoveries in 2015 from fixed price sales contracts were offset by reduced differentials between the Appalachian Basin and ultimate sales prices.

The increase in production sales volumes was primarily the result of increased production from the 2013 and 2014 drilling programs in the Marcellus play. This increase was partially offset by the normal production decline in the Company's producing wells.

EQT Production total operating revenues for the year ended December 31, 2015 included a $385.1 million gain on derivatives not designated as hedges compared to an $83.8 million gain on derivatives not designated as hedges for the year ended December 31, 2014. The increased gains for the year ended December 31, 2015 primarily related to favorable changes in the fair market value of EQT Production's NYMEX swaps due to a decrease in forward NYMEX prices during the year ended December 31, 2015. EQT Production received $170.3 million and $36.5 million of net cash settlements for derivatives not designated as hedges for the years ended December 31, 2015 and 2014, respectively. These net cash settlements are included in the average realized price discussion. For the year ended December 31, 2014, EQT Production total operating revenues also included a $24.8 million gain for hedging ineffectiveness.

Operating expenses totaled $1,436.0 million for 2015 compared to $1,334.7 million for 2014. The increase in operating expenses was the result of increases in DD&A, transportation and processing, exploration, SG&A, and LOE expenses, partly offset by decreases in non-cash impairments of long-lived assets and production taxes. The increase in DD&A expense was the result of higher produced volumes partly offset by a lower overall depletion rate in 2015. Transportation and processing expenses increased by $73.8 million due to additional contracted capacity to move EQT Production's natural gas out of the Appalachian Basin and increased liquids processing fees. Transportation and processing expenses are included in the average realized price to EQT Production. Exploration expense increased $40.3 million due to increased lease expirations of non-core acreage totaling $22.8 million and expenses related to exploratory wells. The increase in SG&A expense was primarily due to higher personnel costs of $14.7 million, including incentive compensation expenses, and $11.2 million of drilling program reduction charges, including rig release penalties, partly offset by $4.2 million of higher litigation and environmental remediation costs in the prior year, a $2.6 million decrease in professional services costs and a $2.4 million reduction to the reserve for uncollectible accounts. The increase in LOE was primarily due to increased Marcellus activity, including a $1.4 million increase in salt water disposal costs, and increased Permian maintenance costs. Production taxes decreased primarily due to a $16.7 million decrease in severance taxes due to lower market sales prices, partly offset by higher production sales volumes in certain jurisdictions subject to these taxes and a $3.6 million increase in property taxes. Production taxes also decreased due to a $1.4 million decrease in the Pennsylvania impact fee, primarily as a result of a decrease in the number of wells drilled in Pennsylvania in 2015.

Year Ended December 31, 2014 vs. December 31, 2013

EQT Production's operating income totaled $506.0 million for 2014 compared to $371.2 million for 2013. The $134.8 million increase in operating income was primarily due to increased sales of produced natural gas and NGLs and a higher average realized price partially offset by an increase in operating expenses, which included $267.3 million of noncash impairment charges. Impairment charges consisted of $105.2 million associated with proved properties in the Permian Basin of Texas related to the 2014 decline in commodity prices. Impairment charges also included $86.6 million associated with undeveloped properties and $75.5 million associated with proved properties in the Utica Shale of Ohio as a result of insufficient recovery of hydrocarbons to support continued development along with the decline in commodity prices.

Total operating revenues were $1,813.3 million for 2014 compared to $1,310.9 million for 2013. The $502.4 million increase in total operating revenues was primarily due to a 26% increase in production sales volumes, a favorable gain on derivatives not designated as hedges, a favorable change in hedging ineffectiveness and a 3% increase in the average realized price to EQT Production. The increase in production sales volumes was the result of increased production from the 2014 and 2013 drilling programs, primarily in the Marcellus play. This increase was partially offset by the normal production decline in the Company's producing wells.

Total operating revenues for the year ended December 31, 2014 included a $24.8 million gain for hedging ineffectiveness of financial hedges compared to a $21.3 million loss for ineffectiveness of financial hedges for the year ended December 31, 2013. The year ended December 31, 2014 also included $83.8 million of derivative gains for derivative instruments not designated as hedging instruments compared to $0.3 million of derivative losses for the year ended December 31, 2013. The gains for the year ended December 31, 2014 related to favorable changes in the fair market value of basis swaps and NYMEX collars that were not designated as hedging instruments, due to decreased forward NYMEX and basis prices as of December 31, 2014. EQT Production received $36.5 million of net cash settlements for derivatives not designated as hedges for the year ended December 31, 2014. These net cash settlements are included in the average realized price.

The $0.08 per Mcfe increase in the average realized price to EQT Production was the net result of an increase in the average NYMEX natural gas price net of cash settled derivatives combined with a per unit decrease in midstream revenue deductions, partly offset by a lower average natural gas differential of $0.40 per Mcf. The average differential included lower Appalachian Basin basis of $0.91 per Mcf, favorable recoveries of $0.45 per Mcf and favorable settlements of basis swaps of $0.06 per Mcf. For the year ended December 31, 2014, EQT Production recognized higher recoveries compared to 2013 primarily by using its contracted transportation capacity to sell gas in higher priced markets, particularly during the winter months when market prices in the United States Northeast region were significantly higher than the Appalachian Basin prices. Much of these higher revenues resulted from sales of the Company's Texas Eastern Transmission (TETCO) and Tennessee Gas Pipeline capacity, including additional TETCO capacity that came online in 2014. Effective February 2014, the Company acquired new TETCO capacity of 245,000 MMBtu per day that enabled the Company to reach markets in eastern Pennsylvania. Effective November 2014, additional TETCO capacity of 300,000 MMBtu per day came online that enabled the Company to reach markets in New Jersey as well as markets along the Gulf coast. Additionally, the Company executed natural gas sales with fixed differentials to NYMEX for the 2014 summer term during the fourth quarter of 2013 and first quarter of 2014 when market prices were favorable compared to actual Appalachian Basin basis during the summer of 2014.

Operating expenses totaled $1,334.7 million for 2014 compared to $939.7 million for 2013. The increase in operating expenses was the result of impairments of long-lived assets of $267.3 million, as previously mentioned, and increases in SG&A, production taxes, DD&A, LOE and exploration expenses. SG&A expense increased in 2014 primarily as a result of higher personnel costs of $12.4 million, including incentive compensation expenses, higher litigation and environmental reserves of $6.2 million, and an increase in professional services of $4.9 million. Production taxes increased due to an $11.6 million increase in severance taxes and property taxes as a result of higher market sales prices and higher production sales volumes in certain jurisdictions subject to these taxes. Production taxes also increased due to a $5.1 million increase in the Pennsylvania impact fee, primarily as a result of an increase in the number of wells drilled in Pennsylvania in 2014. Depletion expense increased as a result of higher production sales volumes in 2014, partially offset by a lower overall depletion rate. The increase in LOE was mainly a result of increased Marcellus activity in 2014, including a $2.8 million increase in salt water disposal expenses and a $2.7 million increase in labor expenses, along with expenses related to the exchange of properties with Range. Exploration expense increased in 2014 primarily as a result of increased geophysical activity compared to 2013.

In connection with an asset exchange with Range in 2014, the Company received acreage and producing wells in the Permian Basin of Texas in exchange for acreage, producing wells, the Company's 50% ownership interest in a supporting gathering system in the Nora fields of Virginia and cash of $167.3 million. In conjunction with the transaction, EQT Production recognized a pre-tax gain of $27.4 million in 2014, which is included in gain on sale / exchange of assets in the Statements of Consolidated Income.

The $27.4 million pre-tax gain included a $28.0 million pre-tax gain related to the de-designation of certain derivative instruments that were previously designated as cash flow hedges because it was probable that the forecasted transactions would not occur.

EQT Midstream

Results of Operations

	Years Ended December 31,				
	2015	2014	% change 2015 - 2014	2013	% change 2014 - 2013
OPERATIONAL DATA					
Net operating revenues (thousands):					
Gathering					
Firm reservation fee revenues	$ 272,758	$ 42,604	540.2	$ 5,155	726.5
Volumetric based fee revenues:					
Usage fees under firm contracts (a)	33,415	44,654	(25.2)	—	100.0
Usage fees under interruptible contracts	198,365	310,620	(36.1)	346,255	(10.3)
Total volumetric based fee revenues	231,780	355,274	(34.8)	346,255	2.6
Total gathering revenues	$ 504,538	$ 397,878	26.8	$ 351,410	13.2
Transmission					
Firm reservation fee revenues	$ 221,160	$ 176,890	25.0	$ 116,303	52.1
Volumetric based fee revenues:					
Usage fees under firm contracts (a)	42,035	41,528	1.2	42,080	(1.3)
Usage fees under interruptible contracts	4,481	8,080	(44.5)	2,238	261.0
Total volumetric based fee revenues	46,516	49,608	(6.2)	44,318	11.9
Total transmission revenues	$ 267,676	$ 226,498	18.2	$ 160,621	41.0
Storage, marketing and other net revenues	26,049	30,728	(15.2)	33,555	(8.4)
Total net operating revenues	$ 798,263	$ 655,104	21.9	$ 545,586	20.1
Gathered volumes (BBtu per day):					
Firm reservation	1,149	172	568.0	—	100.0
Volumetric based services (b)	918	1,445	(36.5)	1,278	13.1
Total gathered volumes	2,067	1,617	27.8	1,278	26.5
Gathering and compression expense ($/MMBtu)	$ 0.12	$ 0.14	(14.3)	$ 0.18	(22.2)
Transmission pipeline throughput (BBtu per day):					
Firm capacity reservation	1,841	1,405	31.0	855	64.3
Volumetric based services (b)	281	389	(27.8)	291	33.7
Total transmission pipeline throughput	2,122	1,794	18.3	1,146	56.5
Average contracted firm transmission reservation commitments (BBtu per day)	2,624	2,056	27.6	1,305	57.5
Capital expenditures (thousands)	$ 486,809	$ 455,359	6.9	$ 369,399	23.3
FINANCIAL DATA (thousands)					
Total operating revenues	$ 807,904	$ 699,083	15.6	$ 614,042	13.8
Purchased gas costs	9,641	43,979	(78.1)	68,456	(35.8)
Total net operating revenues	798,263	655,104	21.9	545,586	20.1
Operating expenses:					
Operating and maintenance (O&M)	124,030	108,359	14.5	97,540	11.1
SG&A	101,374	82,165	23.4	63,850	28.7
DD&A	95,280	87,034	9.5	75,032	16.0
Impairment of long-lived assets	4,201	—	100.0	—	—
Total operating expenses	324,885	277,558	17.1	236,422	17.4
Gain on sale / exchange of assets	—	6,763	(100.0)	19,618	(65.5)
Operating income	$ 473,378	$ 384,309	23.2	$ 328,782	16.9

(a) Includes commodity charges and fees on volumes gathered or transported in excess of firm contracted capacity.
(b) Includes volumes gathered or transported under interruptible contracts and volumes in excess of firm contracted capacity.

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

EQT Midstream's operating income totaled $473.4 million for the year ended December 31, 2015, an increase of $89.1 million in 2015 compared to 2014. The increase in operating income was primarily the result of increased gathering and transmission operating revenues from affiliates, partly offset by increased operating expenses, a decrease in storage, marketing and other net operating revenues and a gain on the sale/exchange of assets in 2014.

Gathering revenues increased by $106.7 million primarily as a result of higher affiliate volumes gathered in 2015 compared to 2014, driven by production development in the Marcellus Shale. EQT Midstream significantly increased firm reservation fee revenues in 2015 compared to 2014 as a result of increased capacity under firm contracts with affiliates. The decrease in usage fees was primarily due to affiliates contracting for additional firm capacity.

Transmission revenues increased by $41.2 million in 2015 compared to 2014, reflecting continued production development in the Marcellus Shale by affiliate and third-party producers. The increase primarily resulted from higher firm reservation fees of $44.3 million, partly offset by lower usage fees under interruptible contracts. The decrease in usage fees was primarily due to customers contracting for additional firm capacity.

Storage, marketing and other net operating revenues decreased from the prior year primarily as a result of lower revenues on NGLs marketed for non-affiliate producers as a result of lower liquids pricing in the current year and reduced marketing activity.

Total operating revenues increased by $108.8 million primarily as a result of increased gathering and transmission revenue offset by reduced gas marketing activity. Purchased gas costs decreased $34.3 million primarily as a result of reduced natural gas purchases from affiliates for gas marketing activities.

Total operating expenses increased $47.3 million in 2015 compared to 2014. O&M expense increased $15.7 million as a result of higher compressor and pipeline expenses of $5.0 million related to an increase in Marcellus activity, higher property taxes of $4.4 million, higher personnel costs of $2.4 million, increased allocated expenses from affiliates of $2.0 million and increased contract labor of $1.2 million. SG&A expense increased $19.2 million primarily as a result of increased allocated expenses from affiliates of $5.8 million, higher personnel costs of $5.5 million, higher professional services costs of $3.2 million and charges to write off expired right of ways options of $1.9 million. DD&A increased $8.2 million as a result of additional assets placed in-service. The $4.2 million impairment of long-lived assets in 2015 reflects the Company's decision to sell certain field level NGL processing equipment that is not being used.

Year Ended December 31, 2014 vs. December 31, 2013

EQT Midstream's operating income totaled $384.3 million, an increase of $55.5 million in 2014 compared to 2013. The increase was the result of increased transmission and gathering net operating revenues partly offset by increased operating expenses, lower gains on asset sales and a decrease in storage, marketing and other net operating revenues.

Gathering revenues increased by $46.5 million primarily as a result of higher affiliate volumes gathered in 2014 compared to 2013, driven by production development in the Marcellus Shale. EQT Midstream significantly increased firm reservation fee revenues and related usage charges in 2014 compared to 2013 as a result of increased capacity and volumes gathered under firm contracts with affiliates. The decrease in usage fees under interruptible contracts was primarily due to affiliates contracting for additional firm capacity.

Transmission revenues increased by $65.9 million in 2014 compared to 2013, reflecting continued production development in the Marcellus Shale by third-party and affiliate producers. The increase primarily resulted from higher firm reservation fee revenues of $60.6 million for third parties and EQT Production, including $14.7 million related to the AVC facilities, and higher usage fees under interruptible contracts.

Storage, marketing and other net operating revenues decreased from 2013 to 2014 primarily as a result of $9.3 million of reduced marketing revenues primarily as a result of the sale of certain energy marketing contracts on December 31, 2013 and $9.0 million of lower revenues on NGLs marketed for non-affiliated producers as a result of lower prices and volumes, partly offset by increased storage revenues on the AVC facilities.

Total operating revenues increased $85.0 million primarily as a result of increased transmission and gathering revenue, partly offset by reduced gas marketing activity. Total purchased gas costs decreased $24.5 million primarily as a result of reduced gas marketing activity.

Operating expenses totaled $277.6 million, an increase of $41.1 million in 2014 compared to 2013. O&M expense increased as a result of $8.6 million in higher compression and pipeline operating expenses related to an increase in Marcellus activity and operating the AVC facilities as well as higher labor costs. The increase in SG&A was primarily the result of increased personnel costs of $9.8 million, increased overhead allocated from affiliates of $4.2 million and increased professional services of $2.3 million. DD&A increased as a result of additional assets placed in-service, including the AVC facilities.

In 2013, the Company sold certain energy marketing contracts to a third party for $20.0 million. In conjunction with this transaction, the Company recognized a pre-tax gain of $19.6 million in 2013. In connection with an asset exchange with Range during 2014, EQT Midstream recognized a pre-tax gain of $6.8 million. The difference in the gains on these two transactions resulted in the decrease in gain on sale / exchange of assets in 2014 compared to 2013.

Other Income Statement Items

Other Income

	Years Ended December 31,		
	2015	2014	2013
		(Thousands)	
Other income	$ 9,953	$ 6,853	$ 9,242

Other income includes equity in earnings of nonconsolidated investments. For the years ended December 31, 2015, 2014 and 2013, the Company recorded equity in earnings of nonconsolidated investments of $2.6 million related to EQM's investment in the MVP Joint Venture, $3.4 million related to the Company's prior investment in Nora Gathering, LLC (Nora LLC) and $7.6 million related to the Company's prior investment in Nora LLC, respectively. In connection with the asset exchange with Range in 2014, the Company transferred its 50% ownership interest in Nora LLC to Range. See Note 8 to the Consolidated Financial Statements.

Other income also includes AFUDC. For the years ended December 31, 2015, 2014 and 2013, the Company recorded AFUDC of $6.3 million, $3.2 million and $1.2 million, respectively. The increases in AFUDC primarily related to increased spending by EQM related to the OVC project.

Interest Expense

	Years Ended December 31,		
	2015	2014	2013
		(Thousands)	
Interest expense	$ 146,531	$ 136,537	$ 142,688

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

Interest expense decreased $6.2 million in 2014 compared to 2013 due to higher capitalized interest of $35.0 million on increased Marcellus well development in 2014 compared to $22.9 million in 2013, partially offset by an increase in interest expense of $8.3 million related to EQM's issuance of 4.00% senior notes due 2024.

The weighted average annual interest rates on the Company's long-term debt, excluding EQM's long-term debt, was 6.5%, 6.4%, and 6.4% for 2015, 2014 and 2013, respectively. The weighted average annual interest rate on EQM's long-term debt was 4.0% for both 2015 and 2014. EQM had no long-term debt outstanding in 2013.

The Company did not have any borrowings outstanding at any time under its revolving credit facility during the years ended December 31, 2015 and 2014. The maximum amount of outstanding borrowings at any time under the Company's credit facility during the year ended December 31, 2013 was $178.5 million. The average daily balance of such borrowings outstanding for the Company during the year ended December 31, 2013 was approximately $12.1 million at a weighted average annual interest rate of 1.7%. The maximum amount of outstanding borrowings under EQM's revolving credit facility at any time during the years ended December 31, 2015 and 2014 was $404 million and $450 million, respectively. The average daily balance of borrowings outstanding under EQM's credit facility was approximately $261 million and $119 million during the years ended December 31, 2015 and 2014, respectively. Interest was incurred on such borrowings at a weighted average annual interest rate of approximately 1.7% for the years ended December 31, 2015 and 2014, respectively. EQM had no borrowings outstanding under its credit facility at any time during the year ended December 31, 2013.

Income Taxes

	Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Income tax expense	$ 104,675	$ 214,092	$ 175,186

Income tax expense decreased $109.4 million in 2015 compared to 2014 primarily as a result of lower pre-tax income and a realized $35.4 million tax benefit in connection with recent Internal Revenue Service (IRS) guidance received by the Company in connection with the Company's sale of Equitable Gas in 2013 (discussed below). These benefits were partially offset by an increase in expense of $79.5 million primarily related to valuation allowances recorded on Pennsylvania state net operating loss (NOL) carryforwards during the period. The Company's effective income tax rate decreased to 24.5% in 2015 from 29.6% in 2014. The decrease in the effective income tax rate from 2014 is primarily attributable to an increase in earnings allocated to noncontrolling limited partners of EQGP and EQM, the effects of the IRS guidance, a decrease in EQT Production's operating income, increased tax credits in 2015 and a decrease in state taxes in 2015 as a result of lower pre-tax income on state income tax paying entities. These items were significantly offset by the valuation allowance recorded primarily on Pennsylvania state NOLs. The overall rate was lower for both periods as the Company consolidates 100% of the pre-tax income related to the noncontrolling public limited partners' share of EQGP earnings, but is not required to record an income tax provision with respect to the portion of the earnings allocated to EQM and EQGP noncontrolling public limited partners. Earnings allocated to the EQM and EQGP noncontrolling public limited partners increased in 2015 compared to 2014 primarily as a result of higher net income at EQM and increased noncontrolling interests as a result of EQM's March and November 2015 public offerings of common units, issuances of EQM common units under the $750 million ATM Program and EQGP's IPO.

During 2015, the Company realized a $35.4 million tax benefit in connection with recent IRS guidance received by the Company regarding the Company's sale of Equitable Gas, a regulated entity, in 2013. The transaction included a partial like-kind exchange of assets that resulted in tax deferral for the Company. However, in order to be in compliance with the normalization rules of the Internal Revenue Code, the IRS guidance held that the deferred tax liability associated with the exchanged regulatory assets should not be considered for ratemaking purposes. As a result, during the second quarter of 2015, the Company recorded a regulatory asset equal to the taxes deferred from the exchange and an associated income tax benefit. The regulatory asset and deferred taxes will be reversed when the assets are disposed of in a taxable transaction such as a sale of assets or amortized over the 32-year remaining life of the assets received in the exchange, in either event increasing tax expense at that time.

Income tax expense increased $38.9 million in 2014 compared to 2013 as a result of higher pre-tax income partly offset by a decrease in the Company's effective income tax rate from 33.6% to 29.6%. The decrease in the rate in 2014 compared to 2013 was primarily related to an internal reorganization of subsidiaries resulting in a reduction of state taxes as well as an increase in noncontrolling interests related to EQM's ownership structure. For both periods, the overall rate was lower than the federal statutory rate as the Company consolidates 100% of the pre-tax income related to the noncontrolling public limited partners' share of partnership earnings, but is not required to record an income tax provision with respect to the portion of EQM's earnings allocated to the noncontrolling public limited partners. EQM's earnings increased primarily due to the Sunrise Merger in 2013 and the Jupiter Transaction in 2014, each of which also resulted in increases in the noncontrolling limited public partners' share of partnership earnings (as described in Note 4 to the Consolidated Financial Statements).

The Company has been in an overall federal taxable income position for the past three years primarily as a result of tax gains generated from the net proceeds received from the EQGP IPO and the NWV Gathering Transaction in 2015, the Jupiter Transaction in 2014 and the Sunrise Merger and the Equitable Gas Transaction in 2013. During these periods, the Company utilized the NOLs generated from previous years and no longer had federal NOLs available as of December 31, 2015.

For federal income tax purposes, the Company deducts a portion of drilling costs as intangible drilling costs (IDCs) in the year incurred. IDCs, however, are sometimes limited for purposes of the alternative minimum tax (AMT) and can result in the Company paying AMT even when generating large tax deductions or utilizing a regular tax NOL. See Note 10 to the Consolidated Financial Statements for further discussion of the Company's income taxes.

Income from Discontinued Operations, Net of Tax

	Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Income from discontinued operations, net of tax	$ —	$ 1,371	$ 91,843

Income from discontinued operations, net of tax, was $1.4 million for the year ended December 31, 2014 compared to $91.8 million for the year ended December 31, 2013. On December 17, 2013, the Company and Distribution Holdco, LLC completed the disposition of their ownership interests in Equitable Gas and Homeworks to PNG Companies LLC. See Note 2 to the Consolidated Financial Statements for further discussion of the Company's discontinued operations.

Net Income Attributable to Noncontrolling Interests

	Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Net income attributable to noncontrolling interests	$ 236,715	$ 124,025	$ 47,243

Net income attributable to noncontrolling interests of EQGP and EQM was $236.7 million for 2015 compared to net income attributable to noncontrolling interests of EQM of $124.0 million for 2014. The $112.7 million increase was primarily the result of increased net income at EQM, increased ownership of EQM common units by third parties as a result of EQM's March and November 2015 public offerings of common units and issuances under the $750 million ATM Program, and third-party ownership of EQGP common units as a result of EQGP's IPO.

Net income attributable to noncontrolling interests of EQM was $124.0 million for the year ended December 31, 2014 compared to $47.2 million for the year ended December 31, 2013. The increase resulted from higher capacity reservation revenues and higher gathering revenues in EQM, as well as increased noncontrolling interests in 2014. Noncontrolling interests in EQM increased from 55.4% to 63.6% during the year ended December 31, 2014 as a result of the underwritten public offering of additional common units representing limited partner interests in EQM in May 2014 in connection with the Jupiter Transaction.

Outlook

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

The market prices for natural gas, NGLs and oil were depressed throughout 2015 and the early part of 2016 and continue to be volatile. The average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu from January 1, 2015 through February 10, 2016, and the average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $61.43 per barrel to a low of $26.55 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, the Company is unable to predict future potential movements in the market prices for natural gas, including Appalachian basis, NGLs and oil and thus cannot predict the ultimate impact of prices on its operations. However, the Company does expect natural gas and NGL prices, particularly in the Appalachian Basin, to remain depressed during 2016.

As a result of the continued low price environment, the Company suspended drilling on its Permian Basin, Upper Devonian and Central Pennsylvania Marcellus acreage during 2015 and focused its development plans on its core Marcellus acreage in southwestern Pennsylvania and northern West Virginia and its deep Utica acreage. The Company's 2016 capital expenditure forecast for well development is $820 million, which is 51% lower than its 2015 capital expenditures for well development. Prolonged low, and/or significant or extended declines in, natural gas, NGL and oil prices could adversely affect, among other things, the

Company's development plans, which would decrease the pace of the development and the level of the Company's reserves, as well as the Company's revenues, earnings or liquidity. Low prices may signal a need to further reduce capital spending or record additional non-cash impairments in the book value of the Company’s oil and gas properties or additional downward adjustments to the Company’s estimated proved reserves. Any such additional impairment and/or downward adjustment to the Company’s estimated reserves could potentially be material to the Company. See “Impairment of Oil and Gas Properties” below.

In July 2015, the Company turned in-line its first dry gas focused deep Utica well, which experienced prolific initial results. The Company turned in-line its second deep Utica well in Greene County, Pennsylvania in late December 2015. Given the success of the two initial Utica wells in Greene County, Pennsylvania, the Company has decided to begin development of its deep Utica acreage.

Total capital investment by EQT in 2016, excluding acquisitions, is expected to be approximately $1.8 billion (including EQM). Capital spending for well development (primarily drilling and completion) of approximately $0.8 billion in 2016 is expected to support the drilling of approximately 77 gross wells, including 72 Marcellus wells and 5 deep Utica wells. Depending upon the results of the 5 initial deep Utica wells, the Company may drill an additional 5 deep Utica wells during 2016. Estimated sales volumes are expected to be 700 - 720 Bcfe for an anticipated production sales volume growth of approximately 18% in 2016, while NGL volumes are expected to be 10,000 - 10,500 Mbbls. To support continued growth in production, the Company plans to invest approximately $0.8 billion on midstream infrastructure in 2016, primarily through EQM. The 2016 capital investment plan is expected to be funded by cash on hand, cash flow generated from operations, proceeds from midstream asset sales (dropdowns) to EQM and EQM capital raises.

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

Impairment of Oil and Gas Properties

See “Critical Accounting Policies and Estimates” below and Note 1 to the Consolidated Financial Statements for a discussion of the Company’s accounting policies and significant assumptions related to impairment of the Company’s oil and gas properties. Due to declines in the five-year NYMEX forward strip prices during 2015, an indication of impairment of the Company’s proved oil and gas properties existed as of December 31, 2015. In accordance with its normal procedures, the Company estimated the future undiscounted cash flows from its oil and gas properties and compared these estimates to the carrying value of the properties. As a result of these evaluations, the Company performed discounted cash flow analyses and recorded non-cash, pre-tax impairment charges to its proved oil and gas properties in 2015 including $94.3 million in the non-core Permian basin. 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. Because the estimated future undiscounted cash flows from the Company’s proved oil and gas properties in the Marcellus play and the non-core Huron and Coalbed Methane plays exceeded the carrying values of the respective properties, the Company did not recognize an impairment charge in 2015 related to these oil and gas properties. However, all other things being equal, a further decline in the average five-year NYMEX forward strip prices in a future period may cause the Company to recognize a significant impairment on the assets in the Huron play, which had a carrying value of approximately $3 billion at December 31, 2015.

As described under “Critical Accounting Policies and Estimates” below, the Company makes a number of assumptions related to its accounting for oil and gas properties, many of which require the Company’s management to make significant judgments. These assumptions, which are generally consistent with the assumptions utilized by the Company’s management for internal planning and budgeting purposes, include, among other things, anticipated production from reserves; future market prices for natural gas, NGLs and oil adjusted accordingly for basis differentials; future operating and capital costs; and inflation, some of which are interdependent. Future market prices for natural gas, NGLs and oil are often volatile, and assumptions regarding basis differentials, future production and future operating costs are highly judgmental and in some cases difficult to predict. Due to the uncertainty inherent in, and the interdependence of these factors, the Company cannot predict if future impairment charges, including impairment charges related to its Huron oil and gas properties, will be recognized and, if so, an estimate of the impairment charges that would be recorded in any future period. See “Recent natural gas, NGL and oil price declines have resulted in impairment of certain of our non-core oil and gas properties. Future declines in commodity prices, increases in operating costs or adverse changes in well performance may result in additional write-downs of the carrying amounts of our assets, which could materially and adversely affect our results of operations in future periods.” under Item 1A, “Risk Factors.”

Capital Resources and Liquidity

The Company’s primary sources of cash for the year ended December 31, 2015 were cash flows from operating activities, cash on hand, proceeds from the IPO of EQGP's common units, proceeds from the public offerings of EQM’s common units and an increase in EQM’s debt. The Company’s primary use of cash in 2015 was for capital expenditures.

Operating Activities

The Company’s net cash provided by operating activities decreased $197.8 million from $1,414.7 million in 2014 to $1,216.9 million in 2015. The decrease in cash provided by operating activities was primarily the result of a 36% lower average realized price to EQT Corporation on natural gas, NGL, and oil sales, partially offset by a 27% increase in production sales volume and a decrease in income tax payments.

The Company’s net cash provided by operating activities increased $251.8 million from $1,162.9 million in 2013 to $1,414.7 million in 2014. The increase in cash provided by operating activities was primarily the result of a 26% increase in natural gas and NGL volumes sold, increases in contracted transmission capacity and gathered volumes and a $14.6 million decrease in interest payments, partially offset by a $41.1 million increase in income tax payments primarily due to taxes paid on transactions.

While the Company is unable to predict future movements in the market price for commodities, current prices are lower than average 2015 levels. If current low price trends continue, this trend would negatively impact the Company’s cash flows from operating activities during the year ending December 31, 2016.

Investing Activities

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

Cash flows used in investing activities totaled $2,444.2 million for 2014 as compared to $999.8 million for 2013. The $1,444.4 million increase was primarily attributable to higher capital expenditures in 2014 including the $167.3 million payment in 2014 in connection with the Range asset exchange, compared to proceeds received from the Equitable Gas Transaction of $740.6 million in 2013. As further described below, the Company increased cash capital expenditures from continuing operations by $725 million from 2013 to 2014.

Capital Expenditures for Continuing Operations
($ in millions)

	2015 Actual	2014 Actual	2013 Actual
Well development (primarily drilling and completion)	$ 1,670	$ 1,717	$ 1,237
Property acquisitions	182	724	186
Midstream infrastructure	487	455	369
Other corporate items	5	4	5
Total	$ 2,344	$ 2,900	$ 1,797
Less: non-cash *	(90)	448	70
Total cash capital expenditures	$ 2,434	$ 2,452	$ 1,727

* Capital expenditures for continuing operations included a portion of non-cash stock-based compensation expense and the impact of capital accruals. The capital accrual impact included reversal of the prior year accrual as well as the current year estimate, both of which are non-cash items. The impact of these non-cash items in the table above were $(90) million, $99 million and $70 million for the years ended December 31, 2015, 2014 and 2013, respectively. The year ended December 31, 2014 also included $349 million of non-cash capital expenditures for the exchange of assets with Range.

The Company is estimating a 2016 capital expenditure spending plan of approximately $1.8 billion, which includes $0.8 billion for well development (primarily drilling and completion) and $0.8 billion for total midstream infrastructure. The midstream infrastructure capital expenditures will be made primarily through EQM, for which the Company is estimating a 2016 capital expenditure spending plan of approximately $0.7 billion. The Company does not forecast property acquisitions within its capital spending plan.

Capital expenditures for drilling and development totaled $1,670 million and $1,717 million during 2015 and 2014, respectively. The Company spud 161 gross wells in 2015, including 133 horizontal Marcellus wells with approximately 722,000 feet of pay, 24 horizontal Upper Devonian wells with approximately 146,000 feet of pay and 4 other wells, including 2 deep Utica wells. The Company spud 345 gross wells (342 net wells) in 2014, including 196 horizontal Marcellus wells with approximately 1.1 million feet of pay, 41 horizontal Upper Devonian wells with approximately 260,000 feet of pay, 103 horizontal Huron wells with approximately 605,000 feet of pay and 5 other wells. The $47 million decrease in capital expenditures for well development in 2015 was driven primarily by a decrease in wells spud partly offset by increased costs of deep Utica drilling. Capital expenditures for 2015 also included $189 million for property acquisitions, compared to $724 million of capital expenditures in 2014 for property acquisitions.

Capital expenditures for the midstream operations totaled $487 million for 2015. During 2015, EQT Midstream turned in-line approximately 50 miles of pipeline and 34,000 horsepower of compression primarily in the Marcellus play. During 2014, midstream capital expenditures were $455 million. EQT Midstream turned in-line approximately 60 miles of pipeline and 80,000 horsepower of compression primarily within the Marcellus play. EQT Midstream also added 475 MMcf per day of incremental gathering capacity and 750 MMcf per day of incremental transmission capacity in 2014.

Capital expenditures for drilling and development totaled $1,717 million and $1,237 million during 2014 and 2013, respectively. The Company spud 345 gross wells (342 net wells) in 2014, including 196 horizontal Marcellus wells with approximately 1.1 million feet of pay, 41 horizontal Upper Devonian wells with approximately 260,000 feet of pay, 103 horizontal Huron wells with approximately 605,000 feet of pay and 5 other wells. The Company spud 225 gross wells (224 net wells) in 2013, including 146 horizontal Marcellus wells with approximately 720,000 feet of pay, 22 horizontal Upper Devonian wells with approximately 110,000 feet of pay, 50 horizontal Huron wells with approximately 300,000 feet of pay and 7 other wells. The $480 million increase in capital expenditures for well development in 2014 was driven by an increase in completed frac stages, an increase in wells spud and higher spending in the Huron play. Capital expenditures for 2014 also included $724 million for property acquisitions, including $349 million of non-cash capital expenditures for the exchange of assets with Range.

Capital expenditures for the midstream operations totaled $455 million for 2014. During 2014, EQT Midstream turned in-line approximately 60 miles of pipeline and 80,000 horsepower of compression primarily in the Marcellus play. EQT Midstream also added approximately 475 MMcf per day of incremental gathering capacity and 750 MMcf per day of incremental transmission capacity in 2014. During 2013, midstream capital expenditures were $369 million. EQT Midstream turned in-line approximately 49 miles of pipeline and 2,100 horsepower of compression primarily within the Marcellus play. EQT Midstream also added 385 MMcf per day of incremental gathering capacity and 450 MMcf per day of incremental transmission capacity in 2013.

Financing Activities

Cash flows provided by financing activities totaled $1,832.5 million for 2015 as compared to cash flows provided by financing activities of $1,261.3 million for 2014. In 2015, the Company received net proceeds of $1,182.0 million from EQM's public offerings of common units, including sales under the $750 million ATM Program, net proceeds of $674.0 million from EQGP's IPO and net proceeds of $299.0 million from increased borrowings on EQM's revolving credit facility. The Company repaid maturing long-term debt of approximately $169.0 million, paid distributions to noncontrolling interests of $121.8 million and paid $47.0 million for income tax withholdings related to the vesting or exercise of equity awards during the year ended December 31, 2015. Under the Company's share-based incentive awards, in connection with the settlement of equity awards, the Company may withhold shares or accept surrendered shares from Company employees holding the awards in exchange for satisfying the cash income tax withholding obligations with respect to the settlement of the awards. The Company received proceeds from option exercises and excess tax benefits resulting from option exercises and vesting of awards under employee compensation programs of $37.0 million during the year ended December 31, 2015.

On January 20, 2016, the Board of Directors of the Company declared a regular quarterly cash dividend of three cents per share, payable March 1, 2016, to the Company's shareholders of record at the close of business on February 17, 2016.

On January 21, 2016, the Board of Directors of EQGP's general partner declared a cash distribution to EQGP's unitholders for the fourth quarter of 2015 of $0.122 per common unit, or approximately $32.5 million. The cash distribution will be paid on February 22, 2016 to unitholders of record, including the Company, at the close of business on February 1, 2016.

On January 21, 2016, the Board of Directors of EQM's general partner declared a cash distribution to EQM's unitholders for the fourth quarter of 2015 of $0.71 per common unit. The cash distribution will be paid on February 12, 2016 to unitholders of record, including EQGP, at the close of business on February 1, 2016. EQGP will receive approximately $33.0 million consisting of $15.5 million in respective to its limited partner interest, $1.3 million in respect of its general partner interest and $16.2 million in respect of its IDRs in EQM.

Cash flows provided by financing activities totaled $1,261.3 million for 2014 as compared to cash flows provided by financing activities of $500.5 million for 2013. The Company received net proceeds of $902.5 million from EQM's May 2014 public offering of common units and EQM received net proceeds of $492.3 million from its August 2014 4.00% Senior Notes issuance. EQM paid distributions to noncontrolling interests of $67.8 million in 2014. The Company received proceeds from option exercises and excess tax benefits from exercises and vesting of awards under employee compensation plans of $52.4 million in 2014. The Company used $32.4 million to repurchase and retire shares of the Company's common stock during 2014. In 2013, the Company received net proceeds of $529.4 million from EQM's July 2013 public offering of common units, received proceeds from option exercises and excess tax benefits from exercises and vesting of awards under employee compensation plans of $45.1 million, paid distributions to noncontrolling interests of $32.8 million and repaid maturing long-term debt of $23.2 million.

On April 30, 2014, the Company's Board of Directors approved a share repurchase authorization of up to 1,000,000 shares of the Company's outstanding common stock. The Company may repurchase shares from time to time in open market or in privately negotiated transactions. The share repurchase authorization does not obligate the Company to acquire any specific number of shares, has no pre-established end date and may be discontinued by the Company at any time. During the year ended December 31, 2014, the Company repurchased and retired 300,000 shares of common stock for $32.4 million under the authorization. The Company made no repurchases under the authorization during 2015.

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

Revolving Credit Facilities

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

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

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

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

The Company had no borrowings or letters of credit outstanding under its revolving credit facility as of December 31, 2015 and 2014 or at any time during the years ended December 31, 2015 and 2014. For the years ended December 31, 2015 and 2014, the Company incurred commitment fees averaging approximately 23 basis points to maintain credit availability under its revolving credit facility. The Company's short-term borrowings generally have original maturities of three months or less.

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

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

EQM had $299 million of borrowings and no letters of credit outstanding under its revolving credit facility as of December 31, 2015. EQM had no borrowings or letters of credit outstanding under its revolving credit facility as of December 31, 2014. For the years ended December 31, 2015 and 2014, EQM incurred commitment fees averaging approximately 23 basis points and 24 basis points, respectively, to maintain credit availability under the revolving credit facility.

The maximum amount of outstanding borrowings at any time under EQM's credit facility during the year ended December 31, 2015 was $404 million, and the average daily balance of borrowings outstanding was approximately $261 million at a weighted average annual interest rate of 1.7%. The maximum amount of outstanding borrowings at any time under EQM's credit facility during the year ended December 31, 2014 was $450 million, and the average daily balance of borrowings outstanding was approximately $119 million at a weighted average annual interest rate of 1.7%.

Security Ratings and Financing Triggers

The table below reflects the credit ratings for debt instruments of the Company at February 10, 2016. Changes in credit ratings may affect the Company's cost of short-term and long-term debt (including interest rates and fees under its lines of credit), collateral requirements under derivative instruments, pipeline capacity contracts, joint venture arrangements, subsidiary construction contracts and access to the credit markets.

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

The table below reflects the credit ratings for debt instruments of EQM at December 31, 2015. Changes in credit ratings may affect EQM's cost of short-term and long-term debt (including interest rates and fees under its lines of credit), collateral requirements under joint venture arrangements and construction contracts and access to the credit markets.

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

The Company's and EQM's credit ratings are subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. The Company and EQM cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a credit rating agency if, in its judgment, circumstances so warrant. On December 16, 2015, Moody's announced that it had placed 29 U.S. exploration and production companies, including the Company, under review for a downgrade due to the low commodity price environment. On January 25, 2016, Moody's also announced that it had placed three midstream partnerships, including EQM, under review for a downgrade primarily due to their affiliations with sponsoring exploration and production companies. If Moody's or another 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, the Company 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, 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 ratings agencies. In order to be considered investment grade, a company must be rated BBB- or higher by S&P, Baa3 or higher by Moody's and BBB- or higher by Fitch. Anything below these ratings is considered non-investment grade.

The Company's debt agreements and other financial obligations contain various provisions that, if not complied with, could result in termination of the agreements, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the debt agreements relate to maintenance of a debt-to-total capitalization ratio, limitations on transactions with affiliates, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company's credit facility contains financial covenants that require a total debt-to-total capitalization ratio of no greater than 65%. The calculation of this ratio excludes the effects of accumulated other comprehensive income (OCI). As of December 31, 2015, the Company was in compliance with all debt provisions and covenants.

EQM's debt agreements and other financial obligations contain various provisions that, if not complied with, could result in termination of the agreements, require early payment of amounts outstanding or similar actions. The covenants and events of default under the debt agreements relate to maintenance of permitted leverage ratio, limitations on transactions with affiliates, limitations on restricted payments, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of and certain other defaults under other financial obligations and change of control provisions. Under EQM's credit facility, EQM is required to maintain a consolidated 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, 2015, EQM was in compliance with all debt provisions and covenants.

EQM ATM Program

During 2015, EQM entered into an equity distribution agreement that established EQM's $750 million ATM Program. EQM had approximately $663 million in remaining capacity under the program as of February 10, 2016.

Commodity Risk Management

The substantial majority of the Company's commodity risk management program is related to hedging sales of the Company's produced natural gas. The Company's overall objective in this hedging program is to protect cash flow from undue exposure to the risk of changing commodity prices. The derivative commodity instruments currently utilized by the Company are primarily NYMEX swaps and collars. The Company may also use other contractual agreements in implementing its commodity hedging strategy. The Company also enters into fixed price natural gas sales agreements that are satisfied by physical delivery. The Company does not currently hedge its oil or NGL exposure.

As of February 2, 2016, the approximate volumes and prices of the Company's total hedge position for 2016 through 2018 production are:

	2016**	2017**	2018**
NYMEX Swaps			
Total Volume (Bcf)	280	156	71
Average Price per Mcf (NYMEX)*	$ 3.69	$ 3.44	$ 3.16
Fixed Price Physical Sales ***			
Total Volume (Bcf)	44	9	—
Average Price per Mcf (NYMEX)*	$ 2.92	$ 3.10	$ —
Collars			
Total Volume (Bcf)	—	7	—
Average Floor Price per Mcf (NYMEX)*	$ —	$ 3.15	$ —
Average Cap Price per Mcf (NYMEX)*	$ —	$ 4.03	$ —

* The average price is based on a conversion rate of 1.05 MMBtu/Mcf.

** For 2016 through 2018, the Company also has a natural gas sales agreement for approximately 35 Bcf per year that includes a NYMEX ceiling price of $4.88 per Mcf. The Company also sold calendar year 2016, 2017 and 2018 calls for approximately 11 Bcf, 29 Bcf and 12 Bcf at strike prices of $3.65 per Mcf, $3.52 per Mcf and $3.45 per Mcf, respectively.

*** Fixed price physical sales impact is included in recoveries on the EQT Corporation Price Reconciliation.

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

Other Items

Off-Balance Sheet Arrangements

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that once the energy-efficiency construction was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a period of years. The undiscounted maximum aggregate payments that may be due related to these guarantees were approximately $134 million as of December 31, 2015, extending at a decreasing amount for approximately 12 years.

In December 2014, the Company issued a performance guarantee (the EQT MVP Guarantee) in connection with the obligations of MVP Holdco to fund its proportionate share of the construction budget for the MVP. Upon the transfer of the Company's interest in MVP Holdco to EQM on March 30, 2015, EQM entered into a performance guarantee (the Initial EQM Guarantee) on terms and conditions similar to the EQT MVP Guarantee, and the EQT MVP Guarantee was concurrently terminated. Upon the FERC's initial release to begin construction of the MVP, the Initial EQM Guarantee will terminate, and EQM will be obligated to issue a new guarantee in an amount equal to 33% of MVP Holdco's remaining obligations to make capital contributions to the MVP Joint Venture in connection with the then remaining construction budget, less any credit assurances issued by any affiliate of EQM under such affiliate's precedent agreement with the MVP Joint Venture. As of February 11, 2016, the Initial EQM Guarantee was in the amount of $91 million.

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

Rate Regulation

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

Schedule of Contractual Obligations

The table below presents the Company's long-term contractual obligations as of December 31, 2015 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 $5.7 billion as of December 31, 2015. These capacity commitments have terms extending up to 20 years. For a description of the transportation agreements, see Note 19 to the Consolidated Financial Statements. Purchase obligations also exclude future capital contributions to the MVP Joint Venture and purchase obligations of the MVP Joint Venture.

	Total	2016	2017-2018	2019-2020	2021+
			(Thousands)		
Purchase obligations	$ 11,739,426	$ 381,570	$ 840,301	$ 1,477,370	$ 9,040,185
Long-term debt	2,818,200	—	708,000	711,200	1,399,000
Interest payments on long-term debt (a)	793,667	169,645	305,704	162,174	156,144
Credit facility borrowings	299,000	299,000	—	—	—
Operating leases	155,460	41,526	51,238	21,617	41,079
Pension and other post-retirement benefits	48,800	24,599	3,224	2,954	18,023
Other liabilities	9,484	9,484	—	—	—
Total contractual obligations	$ 15,864,037	$ 925,824	$ 1,908,467	$ 2,375,315	$ 10,654,431

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

Purchase obligations are primarily commitments for demand charges under existing long-term contracts and binding precedent agreements with various unconsolidated pipelines (including MVP), some of which extend up to approximately 20 years. The Company has entered into agreements to release some of its capacity to various third parties. Purchase obligations also include commitments with third parties for processing capacity in order to extract heavier liquid hydrocarbons from the natural gas stream. Operating leases are primarily entered into for various office locations and warehouse buildings, as well as dedicated drilling rigs in support of the Company's drilling program. The obligations for the Company's various office locations and warehouse buildings totaled approximately $90.9 million as of December 31, 2015. The Company has agreements with Orion Drilling Company, Savanna Drilling, LLC and several other drillers to provide drilling equipment and services to the Company over the next four years. These obligations totaled approximately $63.2 million as of December 31, 2015.

The other liabilities line represents commitments for total estimated payouts for the second tranche of the 2014 EQT Value Driver Award Program. See "Critical Accounting Policies and Estimates" below and Note 17 to the Consolidated Financial Statements for further discussion regarding factors that affect the ultimate amount of the payout of these obligations.

As discussed in Note 10 to the Consolidated Financial Statements, the Company had a total reserve for unrecognized tax benefits at December 31, 2015 of $259.3 million, of which $102.7 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.

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 19 to the Consolidated Financial Statements for further discussion of the Company's commitments and contingencies.

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 and possible 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 interdepedent. 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 involves significant judgment about future events such as future sales prices of natural gas and NGLs, future production costs, estimates of the amount of natural gas and NGLs recorded and the timing of those recoveries. See "Impairment of Oil and Gas Properties" above and Note 1 to the Consolidated Financial Statements for additional information regarding the Company's impairments of proved and unproved oil and gas properties.

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

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

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

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

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

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

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

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

Derivative Instruments: The Company enters into derivative commodity instrument contracts primarily to mitigate exposure to commodity price risk associated with future sales of natural gas production. The Company also enters into derivative instruments to hedge other forecasted natural gas purchases and sales, 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, 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 is required to operate and maintain its natural gas pipeline and storage systems, and intends to do so as long as supply and demand for natural gas exists, which the Company expects for the foreseeable future. Therefore, the Company believes that the substantial majority of its natural gas pipeline and storage system assets have indeterminate lives.

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

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

Performance-based awards expected to be satisfied in cash are treated as liability awards. Awards under the 2014 EQT Value Driver Award program are treated as liability awards. Phantom units expected to be satisfied in cash are also treated as liability awards. For liability awards, the Company is required to estimate, on grant date and on each reporting date thereafter until vesting and payment, the fair value of the ultimate payout based upon the expected performance through, and value of the Company's common stock on, the vesting date. The Company then recognizes a proportionate amount of the expense for each period in the Company's financial statements over the vesting period of the award, in the case of a performance-based award, and until payment, in the case of phantom units. 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 or EQM common units are treated as equity awards. Awards under the 2013 Executive Performance Incentive Program, the 2014 Executive Performance Incentive Program, the 2014 EQM Value Driver Award Program, the 2015 Executive Performance Incentive Program, the 2015 EQT Value Driver Award Program and the EQM Total Return Program, each of which remained outstanding at December 31, 2015, 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 or distribution 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 or distribution yield is based on the historical dividend or distribution yield of the Company's common stock or EQM's common units, as applicable, and any changes expected thereto, 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 or EQM's common units and, where applicable, the common stock of the peer group members at the time of grant. The expected term represents the period of time elapsing during the applicable performance period.

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

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

The Company believes that the accounting estimates related to share-based compensation are "critical accounting estimates" because they may change from period to period based on changes in assumptions about factors affecting the ultimate payout of awards, including the number of awards to ultimately vest and the market price and volatility of the Company's common stock and EQM's common units. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions. See Note 17 to the Consolidated Financial Statements for additional information regarding the Company's share-based compensation.

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, NGLs and oil and thus cannot predict the ultimate impact of prices on our operations. However, management does expect natural gas and NGL prices, particularly in the Appalachian Basin, to remain depressed during 2016 and expects market prices for these commodities to continue to be volatile in the future. Prolonged low, and/or significant or extended declines in, natural gas, NGL and oil 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 reserves, as well as the Company’s revenues, earnings or liquidity and could result in a material non-cash impairment in the recorded value of the Company’s oil and gas properties.

The Company's use of derivatives to reduce the effect of commodity price volatility is further described in Notes 1 and 6 to the Consolidated Financial Statements and under the caption “Commodity Risk Management” in the "Capital Resources and Liquidity" section of Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The Company uses derivative commodity instruments that are placed primarily with financial institutions and the creditworthiness of these institutions is regularly monitored. The Company primarily enters into derivative instruments to hedge forecasted sales of production. The Company also enters into derivative instruments to hedge other forecasted natural gas purchases and sales, to hedge basis and to hedge 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. For the derivative commodity instruments used to hedge forecasted natural gas purchases and sales which are exposed to price risk, the Company sets limits related to acceptable exposure levels. The Company does not have any natural gas derivative commodity instruments for trading purposes.

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

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

With respect to the derivative commodity instruments held by the Company as of December 31, 2015 and 2014, the Company hedged portions of expected sales of equity production, portions of forecasted purchases and sales and portions of its basis exposure covering approximately 664 Bcf and 563 Bcf of natural gas, respectively. 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, 2015 and 2014 levels would have increased the fair value of natural gas derivative instruments by approximately $137.1 million and $126.6 million, respectively. A hypothetical increase of 10% in the market price of natural gas from the December 31, 2015 and 2014 levels would have decreased the fair value of natural gas derivative instruments by approximately $138.4 million and $126.5 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, 2015 and December 31, 2014. The price change was then applied to the natural gas derivative commodity instruments recorded on the Company’s Consolidated Balance Sheets, resulting in the change in fair value.

The above analysis of the derivative commodity instruments held by the Company does not include the offsetting impact that the same hypothetical price movement may have on the Company’s physical sales of natural gas. The portfolio of derivative commodity instruments held to hedge the Company’s forecasted equity production 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 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, the derivative commodity instruments continue to function effectively as hedges of the underlying risk, the anticipated transactions occur as expected and basis does not significantly change.

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

Interest Rate Risk

Changes in interest rates affect the amount of interest the Company, EQGP and EQM earn on cash, cash equivalents and short-term investments and the interest rates the Company and EQM pay on borrowings under their respective revolving credit facilities. All of the Company's and EQM's long-term borrowings are fixed rate and thus do not expose the Company to fluctuations in its results of operations or liquidity from changes in market interest rates. Changes in interest rates do affect the fair value of the Company's and EQM's fixed rate debt. See Notes 12 and 13 to the Consolidated Financial Statements for further discussion of the Company's and EQM's borrowings and Note 7 to the Consolidated Financial Statements for a discussion of fair value measurements, including the fair value of long-term debt.

Other Market Risks

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company believes that NYMEX-traded futures contracts have limited credit risk because CFTC regulations are in place to protect exchange participants, including the Company, from potential financial instability of the exchange members. 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 or better, enters into netting agreements whenever possible and may obtain collateral or other security.

Approximately 95%, or $417.4 million, of the Company's OTC derivative contracts outstanding at December 31, 2015 had a positive fair value. Approximately 95%, or $458.5 million, of the Company's OTC derivative contracts outstanding at December 31, 2014 had a positive fair value.

As of December 31, 2015, 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 of EQT Production are generated from the sale of produced natural gas, NGLs and crude oil to certain marketers, utility and industrial customers located mainly in the Appalachian Basin and the Northeastern United States as well as the Permian Basin of Texas and a gas processor in Kentucky and West Virginia. Additionally, a significant amount of revenues and related accounts receivable of EQT Midstream are generated from the transmission and gathering of natural gas in Kentucky, Virginia, Pennsylvania and West Virginia.

The Company has a $1.5 billion revolving credit facility that expires in February 2019. The credit facility is underwritten by a syndicate of financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. As of December 31, 2015, the Company had no borrowings or letters of credit outstanding under the facility. No one lender of the large group of financial institutions in the syndicate holds more than 10% of the facility. The Company's large syndicate group and relatively low percentage of participation by each lender is expected to limit the Company's exposure to problems or consolidation in the banking industry.

EQM has a $750 million revolving credit facility that expires in February 2019. The credit facility is underwritten by a syndicate of financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by EQM. As of December 31, 2015, EQM had $299 million of borrowings and no letters of credit outstanding under the credit facility. No one lender of the large group of financial institutions in the syndicate holds more than 10% of the facility. EQM's large syndicate group and relatively low percentage of participation by each lender is expected to limit EQM's exposure to problems or consolidation in the banking industry.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
EQT Corporation

We have audited the accompanying consolidated balance sheets of EQT Corporation and Subsidiaries as of December 31, 2015 and 2014, and the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2015. Our audits included the financial statement schedule listed in the Index at Item 15 (a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of EQT Corporation and Subsidiaries at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EQT Corporation and Subsidiaries' internal control over financial reporting as of December 31, 2015, 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 11, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania
February 11, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
EQT Corporation

We have audited EQT Corporation and Subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). EQT Corporation and Subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, EQT Corporation and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of EQT Corporation and Subsidiaries as of December 31, 2015 and 2014, and the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2015 and our report dated February 11, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania
February 11, 2016

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

	2015	2014	2013
	(Thousands except per share amounts)		
Revenues:			
Sales of natural gas, oil and NGLs	$ 1,690,360	$ 2,132,409	$ 1,710,245
Pipeline and marketing services	263,640	256,359	148,932
Gain on derivatives not designated as hedges	385,762	80,942	2,834
Total operating revenues	2,339,762	2,469,710	1,862,011
Operating expenses:			
Transportation and processing	275,348	202,203	148,708
Operation and maintenance	124,030	108,283	97,762
Production	123,665	133,488	108,091
Exploration	61,970	21,716	18,483
Selling, general and administrative	249,925	238,134	200,849
Depreciation, depletion and amortization	819,216	679,298	653,132
Impairment of long-lived assets	122,469	267,339	—
Total operating expenses	1,776,623	1,650,461	1,227,025
Gain on sale / exchange of assets	—	34,146	19,618
Operating income	563,139	853,395	654,604
Other income	9,953	6,853	9,242
Interest expense	146,531	136,537	142,688
Income before income taxes	426,561	723,711	521,158
Income tax expense	104,675	214,092	175,186
Income from continuing operations	321,886	509,619	345,972
Income from discontinued operations, net of tax	—	1,371	91,843
Net income	321,886	510,990	437,815
Less: Net income attributable to noncontrolling interests	236,715	124,025	47,243
Net income attributable to EQT Corporation	$ 85,171	$ 386,965	$ 390,572
Amounts attributable to EQT Corporation:			
Income from continuing operations	$ 85,171	$ 385,594	$ 298,729
Income from discontinued operations, net of tax	—	1,371	91,843
Net income	$ 85,171	$ 386,965	$ 390,572
Earnings per share of common stock attributable to EQT Corporation:			
Basic:			
Weighted average common stock outstanding	152,398	151,553	150,574
Income from continuing operations	$ 0.56	$ 2.54	$ 1.98
Income from discontinued operations, net of tax	—	0.01	0.61
Net income	$ 0.56	$ 2.55	$ 2.59
Diluted:			
Weighted average common stock outstanding	152,939	152,513	151,787
Income from continuing operations	$ 0.56	$ 2.53	$ 1.97
Income from discontinued operations, net of tax	—	0.01	0.60
Net income	$ 0.56	$ 2.54	$ 2.57

See notes to consolidated financial statements.

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

	2015	2014	2013
		(Thousands)	
Net income	$ 321,886	$ 510,990	$ 437,815
Other comprehensive (loss) income, net of tax:			
Net change in cash flow hedges:			
Natural gas, net of tax (benefit) expense of ($102,271), $102,850 and ($50,200)	(152,359)	155,422	(76,489)
Interest rate, net of tax expense of $100, $104 and $63	144	145	144
Pension and other post-retirement benefits liability adjustment, net of tax (benefit) expense of ($564), ($515) and $16,115	(901)	(776)	21,501
Other comprehensive (loss) income	(153,116)	154,791	(54,844)
Comprehensive income	168,770	665,781	382,971
Less: Comprehensive income attributable to noncontrolling interests	236,715	124,025	47,243
Comprehensive (loss) income attributable to EQT Corporation	$ (67,945)	$ 541,756	$ 335,728

See notes to consolidated financial statements.

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

	2015	2014	2013
		(Thousands)	
Cash flows from operating activities:			
Net income	$ 321,886	$ 510,990	$ 437,815
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income taxes	17,876	32,021	110,363
Depreciation, depletion and amortization	819,216	679,298	676,570
Impairment of long-lived assets and exploratory well costs	182,242	281,979	14,198
Gain on sale / exchange of assets	—	(34,146)	(19,618)
Gain on dispositions included in discontinued operations	—	(2,898)	(166,276)
(Recoveries of) provision for losses on accounts receivable	(1,903)	88	2,957
Other income	(9,953)	(6,853)	(9,508)
Stock-based compensation expense	58,629	42,123	52,618
(Gain) loss recognized in operating revenues for hedging ineffectiveness	—	(24,774)	21,335
Gain on derivatives not designated as hedges	(385,762)	(80,942)	(2,834)
Cash settlements on derivatives not designated as hedges	172,093	34,239	1,115
Changes in other assets and liabilities:			
Dividend from Nora Gathering, LLC	—	9,463	9,000
Excess tax benefits on stock-based compensation	(22,945)	(33,216)	(12,251)
Accounts receivable	131,031	(70,392)	(44,818)
Accounts payable	(37,623)	30,350	15,990
Other items, net	(27,847)	47,412	76,205
Net cash provided by operating activities	1,216,940	1,414,742	1,162,861
Cash flows from investing activities:			
Capital expenditures from continuing operations	(2,434,018)	(2,277,306)	(1,612,501)
Capital expenditures for acquisitions	—	(174,184)	(114,224)
Capital expenditures from discontinued operations	—	—	(36,637)
Dry hole costs	(17,130)	(166)	—
Capital contributions to Mountain Valley Pipeline, LLC, net of sales of interest	(74,459)	—	—
Proceeds from sale of assets	—	7,444	740,587
Proceeds from sale of energy marketing contracts	—	—	23,000
Net cash used in investing activities	(2,525,607)	(2,444,212)	(999,775)
Cash flows from financing activities:			
Proceeds from the issuance of common units of EQT Midstream Partners, LP, net of issuance costs	1,182,002	902,467	529,442
Proceeds from the sale of common units of EQT GP Holdings, LP, net of sale costs	673,964	—	—
Proceeds from issuance of EQT Midstream Partners, LP debt	—	500,000	—
Increase in borrowings on credit facility	617,000	450,000	178,500
Decrease in borrowings on credit facility	(318,000)	(450,000)	(178,500)
Dividends paid	(18,310)	(18,207)	(18,094)
Distributions to noncontrolling interests	(121,759)	(67,819)	(32,781)
Repayments and retirements of long-term debt	(169,004)	(11,162)	(23,204)
Proceeds and excess tax benefits from awards under employee compensation plans	36,965	52,373	45,137
Cash paid for taxes related to net settlement of share-based incentive awards	(47,013)	(51,262)	—
Debt issuance costs and revolving credit facility origination fees	—	(12,764)	—
Repurchase and retirement of common stock	(3,375)	(32,368)	—
Net cash provided by financing activities	1,832,470	1,261,258	500,500
Net change in cash and cash equivalents	523,803	231,788	663,586
Cash and cash equivalents at beginning of year	1,077,429	845,641	182,055
Cash and cash equivalents at end of year	$ 1,601,232	$ 1,077,429	$ 845,641
Cash paid during the year for:			
Interest, net of amount capitalized	$ 147,550	$ 128,567	$ 143,187

Income taxes, net	$ 95,708	$ 204,818	$ 163,703

See notes to consolidated financial statements.

EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2015	2014
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 1,601,232	$ 1,077,429
Accounts receivable (less accumulated provision for doubtful accounts: $3,018 in 2015; $5,311 in 2014)	176,957	306,085
Derivative instruments, at fair value	417,397	458,460
Prepaid expenses and other	55,433	62,349
Total current assets	2,251,019	1,904,323
Property, plant and equipment	15,635,549	13,427,429
Less: accumulated depreciation and depletion	4,163,528	3,350,615
Net property, plant and equipment	11,472,021	10,076,814
Other assets	253,132	54,216
Total assets	$ 13,976,172	$ 12,035,353

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EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2015	2014
	(Thousands)	
Liabilities and Stockholders' Equity		
Current liabilities:		
Current portion of long-term debt	$ —	$ 165,874
Credit facility borrowings	299,000	—
Accounts payable	291,550	444,077
Derivative instruments, at fair value	23,434	22,942
Other current liabilities	181,835	200,449
Total current liabilities	795,819	833,342
Long-term debt	2,793,343	2,793,479
Deferred income taxes	1,972,170	1,750,870
Other liabilities and credits	386,798	284,599
Total liabilities	5,948,130	5,662,290
Equity:		
Stockholders' equity		
Common stock, no par value, authorized 320,000 shares, shares issued: 158,347 in 2015 and 175,384 in 2014	2,153,280	1,895,632
Treasury stock, shares at cost: 5,793 in 2015 (including 292 held in rabbi trust) and 23,788 in 2014	(104,079)	(429,440)
Retained earnings	2,982,212	2,917,129
Accumulated other comprehensive income	46,378	199,494
Total common stockholders' equity	5,077,791	4,582,815
Noncontrolling interests in consolidated subsidiaries	2,950,251	1,790,248
Total equity	8,028,042	6,373,063
Total liabilities and equity	$ 13,976,172	$ 12,035,353

See notes to consolidated financial statements.

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED EQUITY
YEARS ENDED DECEMBER 31, 2015, 2014 and 2013

	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, 2012	150,109	$ 1,308,771	$ 2,195,502	$ 99,547	$ 284,982	$ 3,888,802
Comprehensive income (net of tax):						
Net income			390,572		47,243	437,815
Net change in cash flow hedges:						
Natural gas, net of tax of ($50,200)				(76,489)		(76,489)
Interest rate, net of tax of $63				144		144
Pension and other post-retirement benefits liability adjustment, net of tax of $16,115				21,501		21,501
Dividends ($0.12 per share)			(18,094)			(18,094)
Stock-based compensation plans, net	775	114,975			454	115,429
Distributions to noncontrolling interests ($1.55 per common unit)					(32,781)	(32,781)
Issuance of common units of EQT Midstream Partners, LP					529,442	529,442
Deferred taxes related to the public offering of common units of EQT Midstream Partners, LP		(1,641)				(1,641)
Balance, December 31, 2013	150,884	$ 1,422,105	$ 2,567,980	$ 44,703	$ 829,340	$ 4,864,128
Comprehensive income (net of tax):						
Net income			386,965		124,025	510,990
Net change in cash flow hedges:						
Natural gas, net of tax of $102,850				155,422		155,422
Interest rate, net of tax of $104				145		145
Pension and other post-retirement benefits liability adjustment, net of tax of ($515)				(776)		(776)
Dividends ($0.12 per share)			(18,207)			(18,207)
Stock-based compensation plans, net	1,012	56,846			2,235	59,081
Distributions to noncontrolling interests ($2.02 per common unit)					(67,819)	(67,819)
Issuance of common units of EQT Midstream Partners, LP					902,467	902,467
Repurchase and retirement of common stock	(300)	(12,759)	(19,609)			(32,368)
Balance, December 31, 2014	151,596	$ 1,466,192	$ 2,917,129	$ 199,494	$ 1,790,248	$ 6,373,063
Comprehensive income (net of tax):						
Net income			85,171		236,715	321,886
Net change in cash flow hedges:						
Natural gas, net of tax of ($102,271)				(152,359)		(152,359)
Interest rate, net of tax of $100				144		144
Pension and other post-retirement benefits liability adjustment, net of tax of ($564)				(901)		(901)
Dividends ($0.12 per share)			(18,310)			(18,310)
Stock-based compensation plans, net	996	77,378			1,056	78,434
Distributions to noncontrolling interests ($2.505 and $0.15139 per common unit for EQT Midstream Partners, LP and EQT GP Holdings, LP, respectively)					(121,759)	(121,759)
Issuance of common units of EQT Midstream Partners, LP					1,182,002	1,182,002
Sale of common units of EQT GP Holdings, LP					673,964	673,964
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

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, 2015

1. Summary of Significant Accounting Policies

Principles of Consolidation: The Consolidated Financial Statements include the accounts of EQT Corporation and all subsidiaries, ventures and partnerships in which a controlling interest is held (EQT or the Company). All significant intercompany accounts and transactions have been eliminated in consolidation. The results of EQT GP Holdings, LP (EQGP) and EQT Midstream Partners, LP (EQM) are both consolidated in the Company's financial statements. The Company records the noncontrolling interests of the public limited partners in its financial statements.

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

The Company reports its operations in two segments, which reflect its lines of business. The EQT Production segment includes the Company's exploration for, and development and production of, natural gas, natural gas liquids (NGLs) and a limited amount of crude oil, primarily in the Appalachian Basin. EQT Midstream's operations include the natural gas gathering, transmission, storage and marketing activities of the Company, including ownership and operation of EQGP and EQM.

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

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

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.

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 year ended December 31, 2015, the Company recorded no lower of cost or market adjustments related to inventory. During the years ended December 31, 2014 and 2013, the Company recorded losses for lower of cost or market adjustments of $3.2 million and $0.4 million, respectively, which became part of the average cost of the inventory.

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

	As of December 31,	
	2015	2014
	(Thousands)	
Oil and gas producing properties, successful efforts method	$ 11,816,769	$ 10,082,825
Accumulated depreciation and depletion	(3,425,618)	(2,693,535)
Net oil and gas producing properties	8,391,151	7,389,290
Midstream plant	3,703,994	3,234,370
Accumulated depreciation and amortization	(685,398)	(606,998)
Net midstream plant	3,018,596	2,627,372
Other properties, at cost less accumulated depreciation	62,274	60,152
Net property, plant and equipment	$ 11,472,021	$ 10,076,814

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, the cost of productive wells, wells and related equipment, development dry holes, as well as productive acreage, including productive mineral interest, 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 $114.4 million, $108.5 million and $93.5 million in 2015, 2014 and 2013, respectively. The Company capitalized $35.8 million, $35.0 million and $22.9 million of interest relative to Marcellus and Utica well development in 2015, 2014 and 2013, respectively. Depletion expense is calculated based on the actual production 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 consist of producing gas properties which were depleted at an overall average rate of $1.18 per Mcfe, $1.22 per Mcfe and $1.50 per Mcfe for the years ended December 31, 2015, 2014 and 2013, 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 and possible reserves, utilizing assumptions generally consistent with the assumptions utilized by the Company's management for internal planning and budgeting purposes, including, among other things, the intended use of the asset, anticipated production from reserves, future market prices for natural gas, NGLs and oil, adjusted accordingly for basis differentials, future operating costs and inflation, some of which are interdependent. Proved oil and gas properties that have carrying amounts in excess of estimated future undiscounted cash flows are written down to fair value, which is estimated by discounting the estimated future cash flows using discount rate and other assumptions that marketplace participants would use in their estimates of fair value.

Due to the decline in commodity prices during 2015 and 2014, there were indications that the carrying values of certain of the Company's oil and gas producing properties were impaired and future undiscounted cash flows attributed to these assets indicated their carrying amounts were not expected to be fully recovered. Their fair value was measured 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 inflated for periods after the five-year forward price curve and included observed basis differentials and contractual transportation costs, future operating costs, which were inflated consistent with price assumptions, as well as the assumed market participant discount rate, which was estimated to be a rate of 12%, were considered to be significant unobservable inputs in the Company's calculation of fair value. As a result, valuation of the impaired assets was considered to be a Level 3 fair value measurement. For the years ended December 31, 2015 and 2014, EQT Production recognized pretax impairment charges on proved oil and gas properties of $98.6 million and $180.7 million, respectively, which are included in impairment of long-lived assets in the Statements of Consolidated Income. 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. Because the estimated future undiscounted cash flows from the Company's proved oil and gas properties in the Marcellus play and the non-core Huron and Coalbed Methane plays exceeded the carrying values of the respective properties, the Company did not recognize an impairment charge in 2015 related to these oil and gas properties. The 2014 impairment included charges of $105.2 million to record the proved properties in the Permian Basin of Texas at a fair value of $109.2 million and $75.5 million to record the proved properties in the Utica Shale of Ohio at a fair value of $7.4 million. The 2015 and 2014 impairments on proved properties in the Permian Basin of Texas were due to a decline in commodity prices. The 2015 and 2014 impairments in the Utica Shale of Ohio were a result of insufficient recovery of hydrocarbons to support continued development, along with the decline in commodity prices. For the year ended December 31, 2013, the Company did not recognize impairment charges on proved oil and gas properties.

Capitalized costs of unproved oil and gas properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period in which that determination is made. For the years ended December 31, 2015 and 2014, EQT Production recorded unproved property impairments of $19.7 million and $86.6 million, respectively, which are included in impairment of long-lived assets in the Statements of Consolidated Income. For the year ended December 31, 2013, the Company did not recognize impairment charges on unproved oil and gas properties. The unproved property impairment in 2015 related to the Company's non-core Marcellus acreage, based on the Company's decision to focus near-term development on its core Marcellus and deep Utica acreage. The unproved property impairment in 2014 related to the Company's decision to stop development of properties in its Utica Shale of Ohio. In addition, unproved oil and gas property impairments primarily as a result of lease expirations prior to drilling of $37.4 million, $14.6 million and $14.2 million are included in exploration expense of EQT Production for the years ended December 31, 2015, 2014 and 2013, respectively. Unproved properties had a net book value of $898.3 million and $824.5 million at December 31, 2015 and 2014, respectively.

At December 31, 2014, the Company had $9.0 million of capitalized exploratory well costs that were pending the determination of proved reserves. These exploratory well costs were reclassified to wells, equipment and facilities during the third quarter of 2015 upon the successful completion of the Company's first deep Utica well in Pennsylvania. During 2015, the Company drilled one exploratory dry hole within its non-core acreage and the related expenditures have been included within exploration expense in the Statements of Consolidated Income as of December 31, 2015. There were no capitalized exploratory wells costs at December 31, 2015 and 2013.

Midstream property, plant and equipment is carried at cost. Depreciation is calculated using the straight-line method based on estimated service lives. Midstream property consists largely of gathering and transmission systems (25 - 60 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).

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

When events or changes in circumstances indicate that the carrying amount of any long-lived asset other than proved and unproved oil and gas properties may not be recoverable, the Company reviews its long-lived assets for impairment by first comparing the carrying value of the assets to the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the assets. If the carrying value exceeds the sum of the assets' undiscounted cash flows, the Company records an impairment loss equal to the difference between the carrying value and fair value of the assets. During the year ended December 31, 2015, EQT Midstream recorded an impairment of long-lived assets of approximately $4.2 million related to an asset that will not be utilized in Midstream operations. No impairment of any long-lived asset other than proved and unproved oil and gas properties was recorded in 2014 or 2013.

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: EQT Midstream's regulated operations include interstate pipeline operations subject to regulation by the Federal Energy Regulatory Commission (FERC) and 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 Income for a non-regulated company. The deferred regulatory assets and liabilities are then recognized in the Statements of Consolidated Income in the period in which the same amounts are reflected in rates.

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

	Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Net revenues	$ 309,984	$ 267,997	$ 184,767
Operating expenses	$ 109,954	$ 89,617	$ 71,517

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

	As of December 31,	
	2015	2014
	(Thousands)	
Property, plant & equipment	$ 1,356,206	$ 1,160,696
Accumulated depreciation and amortization	(193,349)	(188,884)
Net property, plant & equipment	$ 1,162,857	$ 971,812

The regulatory assets associated with deferred taxes of $73.1 million and $15.2 million as of December 31, 2015 and 2014, 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.

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

In regards to commodity price risk, the financial instruments currently utilized by the Company are primarily fixed price swap agreements and collar agreements which may require payments to or receipt of payments from counterparties based on the differential between two prices for the commodity. The Company also uses a limited number of other contractual agreements in implementing its commodity hedging strategy. The Company may execute interest rate swap agreements to hedge exposures to fluctuations in interest rates. The Company does not enter into derivative instruments for trading purposes.

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

Effective December 31, 2014, the Company elected to de-designate all derivative commodity instruments that were designated and qualified as cash flow hedges. If a cash flow hedge was terminated or de-designated as a hedge before the settlement date of the hedged item, the amount of deferred gain or loss within accumulated OCI recorded up to that date remained deferred, provided that the forecasted transaction remained probable of occurring. Subsequent changes in fair value of a de-designated derivative instrument are recorded in earnings. The amount recorded in accumulated OCI is primarily related to instruments that were previously designated as cash flow hedges.

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

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

AFUDC: Carrying costs for the construction of certain long-term assets are capitalized by the Company 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 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 Income. AFUDC interest costs capitalized were $1.6 million, $1.0 million and $0.5 million for the years ended December 31, 2015, 2014 and 2013, 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 Income. The AFUDC equity amounts capitalized were $6.3 million, $3.2 million and $1.2 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Other Current Liabilities: Other current liabilities as of December 31, 2015 and 2014 are detailed below.

	December 31,	
	2015	2014
	(Thousands)	
Incentive compensation	$ 67,049	$ 70,826
Taxes other than income	44,925	52,035
Accrued interest payable	36,330	37,349
All other accrued liabilities	33,531	40,239
Total other current liabilities	$ 181,835	$ 200,449

Revenue Recognition: Revenue is recognized for production and gathering activities when deliveries of natural gas, NGLs and crude oil occur. 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 Income, 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 Income. The Company accounts for gas-balancing arrangements under the entitlement method. The Company uses the gross method to account for overhead cost reimbursements from joint operating partners. During periods in which rates are subject to refund as a result of a pending rate case, the Company records revenue at the rates which are pending approval but reserves these revenues to the level of previously approved rates until the final settlement of the rate case.

Investments in Consolidated Affiliates: In January 2015, the Company formed EQGP to own the Company's partnership interests in EQM. On May 15, 2015, EQGP completed an initial public offering (IPO) of 26,450,000 common units representing limited partner interests in EQGP, which represented 9.9% of EQGP's outstanding limited partner interests. The Company retained 239,715,000 common units, which represented a 90.1% limited partner interest, and the entire non-economic general partner interest, in EQGP. As of December 31, 2015, EQGP owned 21,811,643 EQM common units, representing a 27.6% 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. EQGP and EQM are both consolidated in the Company's consolidated financial statements and the Company records the noncontrolling interests of the public limited partners in its financial statements. See Notes 3 and 4.

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

Unamortized Debt Discount and Issuance Expense: Discounts and expenses incurred with the issuance of long-term debt are amortized over the term of the debt. These amounts are presented as a reduction of long-term debt on the accompanying Consolidated Balance Sheets. See Note 13.

Transportation and Processing: Third-party costs incurred to gather, process and transport gas produced by EQT Production to market sales points are recorded as a portion of transportation and processing costs in the Statements of Consolidated Income. The Company markets some transportation for resale and the related costs are not incurred to transport gas produced by EQT Production. These transportation costs are reflected as a deduction from operating 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 stockholders' 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 Income. 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 Corporation 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 Corporation 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 16.

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

The Company is required to operate and maintain its natural gas pipeline and storage systems, and intends to do so as long as supply and demand for natural gas exists, which the Company expects for the foreseeable future. Therefore, the Company believes that the substantial majority of its natural gas pipeline and storage system assets have indeterminate lives.

The 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,	
	2015	2014
	(Thousands)	
Asset retirement obligation as of beginning of period	$ 140,086	$ 116,045
Accretion expense	10,646	9,420
Liabilities incurred	2,251	16,953
Liabilities settled	(5,027)	(14,025)
Change in estimates	20,186	11,693
Asset retirement obligation as of end of period	$ 168,142	$ 140,086

In connection with the exchange of certain assets with Range Resources Corporation (Range) (see Note 8 for additional information), the Company settled $7.7 million and incurred $14.2 million of asset retirement obligation liabilities during the year ended December 31, 2014. These amounts are included in the respective captions in the table above.

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

Accumulated other comprehensive income: The components of accumulated OCI, net of tax, are as follows:

	As of December 31,	
	2015	**2014**
	(Thousands)	
Net gain from natural gas hedging transactions	$ 64,762	$ 217,121
Net loss from interest rate swaps	(843)	(987)
Pension and other post-retirement benefits liability adjustment	(17,541)	(16,640)
Accumulated OCI	$ 46,378	$ 199,494

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

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. ASU No. 2014-09 will supersede most of the existing revenue recognition requirements in United States GAAP when it becomes effective and is required to be adopted using one of two retrospective application methods. In August 2015, the FASB issued ASU No. 2015-14, *Revenue from Contracts with Customers - Deferral of the Effective Date* which approved a one year deferral of ASU 2014-09 for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. Early application is permitted as of the original effective date for annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. The Company is currently evaluating the method of adoption and impact this standard will have on its financial statements and related disclosures.

In February 2015, the FASB issued ASU No. 2015-02, *Consolidation*. The standard changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. The ASU will be effective for public entities for annual reporting periods beginning after December 15, 2015, including interim periods therein. The Company has evaluated this standard and determined that the adoption of it will have no significant impact on reported results.

In April 2015, the FASB issued ASU No. 2015-03, *Interest - Imputation of Interest*. The standard requires an entity to present the debt issuance costs related to a recognized debt liability as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. In August 2015, the FASB issued ASU No. 2015-15, *Interest - Imputation of Interest*. The standard added Securities and Exchange Commission (SEC) paragraphs to clarify the applicability of ASU No. 2015-03 to debt issuance costs related to line-of-credit arrangements. The guidance in ASU No. 2015-03 is effective for public entities for annual reporting periods beginning after December 15, 2015, including interim periods therein. The Company has early adopted these standards and all prior periods presented in this Annual Report have been recast to reflect the change in accounting principle. The Consolidated Balance Sheet as of December 31, 2014 has been adjusted to apply the change in accounting principle retrospectively, which resulted in a decrease in other assets of $29.5 million, a decrease in the current portion of long-term debt of $0.1 million, a decrease in long-term debt of $29.4 million and a decrease in total liabilities of $29.5 million as of December 31, 2014. There was no impact to the Statements of Consolidated Income as a result of the change in accounting principle.

In April 2015, the FASB issued ASU No. 2015-05, *Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement*. The ASU adds guidance that will help entities evaluate the accounting for fees paid by a customer in a cloud computing arrangement. The ASU will be effective for annual reporting periods beginning after December 15, 2015. The Company has early adopted this standard which had no significant impact on reported results or related disclosures.

In November 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740)*. The ASU requires deferred liabilities and assets to be classified as noncurrent in a classified statement of financial position. The ASU is effective for annual reporting periods beginning after December 15, 2016, including interim periods therein. The Company has early adopted this standard prospectively as of January 1, 2015, which had no significant impact on reported results or related disclosures. Prior periods were not retrospectively adjusted as a result of the change in accounting principle.

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

2. Discontinued Operations

On December 17, 2013, the Company and its indirect wholly owned subsidiary Distribution Holdco, LLC completed the disposition of their ownership interests in Equitable Gas Company, LLC (Equitable Gas) and Equitable Homeworks, LLC (Homeworks) to PNG Companies LLC (the Equitable Gas Transaction). Equitable Gas and Homeworks comprised substantially all of the Company's previously reported Distribution segment. The financial information of Equitable Gas and Homeworks is reflected as discontinued operations for all periods presented in these financial statements. The financial results for 2013 have been recast to reflect the presentation of discontinued operations.

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

During the year ended December 31, 2013, the Company recognized a gain on the sale of $43.8 million, subject to customary post-closing adjustments. The gain is net of tax expense of $122.5 million and is included in income from discontinued operations, net of tax, in the Statements of Consolidated Income.

The following table summarizes the components of discontinued operations activity:

	Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Operating revenues	$ —	$ —	$ 332,947
Income from discontinued operations before income taxes	—	2,377	251,378
Income taxes	—	1,006	159,535
Income from discontinued operations, net of tax	$ —	$ 1,371	$ 91,843

The Company incurred $8.1 million of transaction costs related to the Equitable Gas Transaction for the year ended December 31, 2013, which are included in the results of discontinued operations. The Company also recognized a $51.6 million write off of income tax related regulatory assets (net of related deferred taxes) through income tax expense in discontinued operations in 2013.

3. EQT GP Holdings, LP

In January 2015, the Company formed EQGP, a Delaware limited partnership, to own the Company's partnership interests in EQM. In April 2015, EQT Midstream Investments, LLC, an indirect wholly owned subsidiary of the Company that held EQT's EQM common units, merged with and into EQGP, and EQT Gathering Holdings, LLC (EQT Gathering Holdings), an indirect wholly owned subsidiary of EQT, contributed 100% of the outstanding limited liability company interests in EQT Midstream Services, LLC, EQM's general partner, to EQGP. As a result of these restructuring transactions, EQGP owned the following EQM partnership interests as of December 31, 2015, which represent EQGP's only cash-generating assets: 21,811,643 EQM common units, representing a 27.6% 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, or IDRs, which entitle EQGP to receive up to 48.0% of all incremental cash distributed in a quarter after $0.5250 has been distributed in respect of each common unit and general partner unit of EQM for that quarter. The Company is the ultimate parent company of EQGP and EQM.

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

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 public limited partners in its financial statements. 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.

On January 21, 2016, the Board of Directors of EQGP's general partner declared a cash distribution to EQGP's unitholders for the fourth quarter of 2015 of $0.122 per common unit, or approximately $32.5 million. The distribution will be paid on February 22, 2016 to unitholders of record, including the Company, at the close of business on February 1, 2016.

Net income attributable to noncontrolling interests (i.e., to the EQGP limited partner interests not owned by the Company and the EQM limited partner interests not owned by EQGP) was $236.7 million for the year ended December 31, 2015. Net income attributable to noncontrolling interests (i.e., to the EQM limited partner interests not owned by the Company) was $124.0 million and $47.2 million for the years ended December 31, 2014 and 2013, respectively.

4. EQT Midstream Partners, LP

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

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

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

On May 7, 2014, EQM completed an underwritten public offering of 12,362,500 common units, which included the full exercise of the underwriters' overallotment option. EQM received net proceeds of approximately $902.5 million from the offering, after deducting the underwriters' discount and offering expenses of approximately $34.0 million.

In August 2014, EQM issued 4.00% Senior Notes due 2024 (4.00% Senior Notes) in the aggregate principal amount of $500.0 million. The indenture governing the 4.00% Senior Notes contains covenants that limit EQM's ability to, among other things, incur certain liens securing indebtedness, engage in certain sale and leaseback transactions, and enter into certain consolidations, mergers, conveyances, transfers or leases of all or substantially all of EQM's assets. The payment obligations under the 4.00% Senior Notes were unconditionally guaranteed by each of EQM's subsidiaries that guaranteed EQM's credit facility (other than EQT Midstream Finance Corporation). The subsidiary guarantors were released from their guarantees of the 4.00% Senior Notes in January 2015 in connection with an amendment to EQM's credit facility.

On March 10, 2015, the Company and certain subsidiaries of the Company entered into a contribution and sale agreement (Contribution Agreement) with EQM and EQM Gathering Opco, LLC (EQM Gathering), an indirect wholly owned subsidiary of EQM. Pursuant to the Contribution Agreement, on March 17, 2015, a subsidiary of the Company contributed the Northern West Virginia Marcellus gathering system to EQM Gathering in exchange for total consideration of $925.7 million, consisting of $873.2 million in cash, 511,973 EQM common units and 178,816 EQM general partner units (the NWV Gathering Transaction). EQM Gathering is consolidated by the Company as it is still controlled by the Company. On April 15, 2015, pursuant to the Contribution Agreement, the Company transferred a 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 17, 2015, EQM completed an underwritten public offering of 8,250,000 common units. On March 18, 2015, the underwriters exercised their option to purchase 1,237,500 additional common units on the same terms as the offering. EQM received net proceeds of $696.6 million from the offering after deducting the underwriters' discount and offering expenses of $24.5 million. 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.

On March 30, 2015, the Company assigned 100% of the membership interest in MVP Holdco, LLC (MVP Holdco), an indirect wholly owned subsidiary of the Company that as of February 11, 2016 owned a 45.5% interest (the MVP Interest) in Mountain Valley Pipeline, LLC (MVP Joint Venture), to EQM for $54.2 million, which represented EQM's reimbursement to the Company for 100% of the capital contributions made by the Company to the MVP Joint Venture as of March 30, 2015. 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. The MVP Joint Venture submitted the MVP certificate application to the FERC in October 2015 and anticipates receiving the certificate in the fourth quarter of 2016. Subject to FERC approval, construction is scheduled to begin shortly thereafter and the pipeline is expected to be in-service during the fourth quarter of 2018. The MVP Joint Venture has been determined to be a variable interest entity because the MVP Joint Venture has insufficient equity to finance activities during the construction stage of the project. EQM is not the primary beneficiary because it does not have the power to direct the activities of the MVP Joint Venture that most significantly impact its economic performance. Beginning on the date it was assumed from the Company, EQM accounted for the MVP Interest as an equity method investment as EQM has the ability to exercise significant influence over operating and financial policies of the MVP Joint Venture.

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 (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 during the first quarter of 2016, ConEd reimbursed EQM for $12.5 million related to the proportionate reduction in EQM's interest in the joint venture. ConEd has the right to terminate its purchase of the interest in the MVP Joint Venture and be reimbursed for the purchase price and all capital contributions made to the MVP Joint Venture for a period ending no later than December 31, 2016.

During the second half of 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). EQM issued 1,162,475 common units at an average price per unit of $74.92 during the six months ended December 31, 2015. EQM received net proceeds of approximately $85.5 million after deducting commissions of approximately $0.9 million and other offering expenses of approximately $0.7 million. EQM used the net proceeds from the sales for general partnership purposes. In connection with the offerings, the Company recorded a $12.4 million gain to additional paid-in-capital, a decrease in noncontrolling interest in consolidated subsidiary of $19.8 million and an increase to deferred tax liability of $7.4 million.

On November 16, 2015, EQM completed an underwritten public offering of 5,650,000 common units. EQM received net proceeds of $399.9 million from the offering after deducting the underwriters' discount and offering expenses of $5.7 million. EQM will use the net proceeds from the offering for general partnership purposes, including to fund a portion of EQM's anticipated 2016 capital expenditures related to transmission and gathering expansion projects and to repay amounts outstanding under EQM's credit facility. In connection with the offering, the Company recorded a $52.1 million gain to additional paid-in-capital, a decrease in noncontrolling interest in consolidated subsidiary of $83.5 million and an increase to deferred tax liability of $31.3 million.

On January 21, 2016, the Board of Directors of EQM's general partner declared a cash distribution to EQM's unitholders for the fourth quarter of 2015 of $0.71 per common unit. The cash distribution will be paid on February 12, 2016 to unitholders of record, including EQGP, at the close of business on February 1, 2016. EQGP will receive approximately $33.0 million consisting of $15.5 million in respect of its limited partner interest, $1.3 million in respect of its general partner interest and $16.2 million in respect of its IDRs in EQM.

5. Financial Information by Business Segment

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

The Company reports its operations in two segments, which reflect its lines of business. The EQT Production segment includes the Company's exploration for, and development and production of, natural gas, NGLs and a limited amount of crude oil in the Appalachian and Permian Basins. The EQT Midstream segment's operations include the natural gas gathering, transmission, storage and marketing activities of the Company, including ownership and operation of EQGP and EQM. EQT Production segment revenues in the table below are reduced by charges from EQT Midstream for midstream services. On the Statements of Consolidated Income, the sales of natural gas, oil and NGLs are not reduced by these charges.

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 United States.

	Years Ended December 31,		
	2015	2014	2013
		(Thousands)	
Revenues from external customers, including affiliates:			
EQT Production	$ 1,540,889	$ 1,813,292	$ 1,310,938
EQT Midstream	807,904	699,083	614,042
Less intersegment revenues, net (a)	(9,031)	(42,665)	(62,969)
Total	$ 2,339,762	$ 2,469,710	$ 1,862,011
Operating income:			
EQT Production (b)	$ 104,865	$ 505,950	$ 371,245
EQT Midstream (b)	473,378	384,309	328,782
Unallocated expenses (c)	(15,104)	(36,864)	(45,423)
Total operating income	$ 563,139	$ 853,395	$ 654,604
Reconciliation of operating income to income from continuing operations:			
Other income	$ 9,953	$ 6,853	$ 9,242
Interest expense	146,531	136,537	142,688
Income tax expense	104,675	214,092	175,186
Income from continuing operations	$ 321,886	$ 509,619	$ 345,972

	As of December 31,		
	2015	2014	2013
		(Thousands)	
Segment assets:			
EQT Production	$ 8,995,853	$ 8,153,199	$ 6,359,065
EQT Midstream	3,226,138	2,709,052	2,514,429
Total operating segments	12,221,991	10,862,251	8,873,494
Headquarters assets, including cash and short-term investments	1,754,181	1,173,102	892,413
Total assets	$ 13,976,172	$ 12,035,353	$ 9,765,907

(a) Eliminates intercompany natural gas sales from EQT Production to EQT Midstream.

(b) Gains on sales / exchanges of assets of $27.4 million and $6.8 million are included in EQT Production and EQT Midstream operating income, respectively, for 2014. See Note 8. Impairment of long-lived assets of $118.3 million and $267.3 million are included in EQT Production operating income for 2015 and 2014, respectively. Impairment of long-lived assets of $4.2 million is included in EQT Midstream operating income for 2015. See Note 1 for a discussion of impairment of long-lived assets.

(c) Unallocated expenses consist primarily of a $20.0 million contribution to the EQT Foundation in 2014, incentive compensation expense, and administrative costs.

	Years Ended December 31,		
	2015	2014	2013
		(Thousands)	
Depreciation, depletion and amortization:			
EQT Production	$ 723,448	$ 592,855	$ 578,641
EQT Midstream	95,280	87,034	75,032
Other	488	(591)	(541)
Total	$ 819,216	$ 679,298	$ 653,132
Expenditures for segment assets: (d)			
EQT Production (e)	$ 1,852,100	$ 2,441,486	$ 1,423,185
EQT Midstream	486,809	455,359	369,399
Other	5,505	3,341	4,292
Total	$ 2,344,414	$ 2,900,186	$ 1,796,876

(d) Includes a portion of non-cash stock-based compensation expense and the impact of capital accruals.

(e) Expenditures for segment assets in the EQT Production segment included $182.3 million, $724.4 million and $186.2 million for property acquisitions in 2015, 2014 and 2013, respectively. Included within the $724.4 million of property acquisitions for the year ended December 31, 2014 was $349.2 million of non-cash capital expenditures for the exchange of assets with Range (described in Note 8).

6. Derivative Instruments

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

The Company uses over the counter (OTC) derivative commodity instruments, primarily swap and collar agreements that are primarily placed with financial institutions. The creditworthiness of all counterparties is regularly monitored. The Company also uses exchange traded futures contracts that obligate the Company to buy or sell a designated commodity at a future date for a specified price and quantity at a specified location. 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 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 call options.

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 accounting for the changes in fair value of the Company's derivative instruments depends on the use of the derivative instruments. To the extent that a derivative instrument had been designated and qualified as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of accumulated OCI, net of tax, and is subsequently reclassified into the Statements of Consolidated Income in the same period or periods during which the forecasted transaction affects earnings. In conjunction with the exchange of assets with Range (see Note 8), the Company de-designated certain derivative instruments that were previously designated as cash flow hedges because it was probable that the forecasted transactions would not occur, resulting in a pre-tax gain of $28.0 million recorded within gain on sale / exchange of assets in the Statements of

Consolidated Income for the year ended December 31, 2014. Any subsequent changes in fair value of these derivative instruments are recognized within operating revenues in the Statements of Consolidated Income each period.

Historically, 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 sale of equity production and forecasted natural gas purchases and sales were designated and qualified as cash flow hedges. As of December 31, 2015 and 2014, the Company deferred net gains of $64.8 million and $217.1 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. Effective December 31, 2014, the Company elected to de-designate all cash flow hedges and discontinue the use of cash flow hedge accounting. As of December 31, 2015 and 2014, the forecasted transactions 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. The Company estimates that approximately $54.7 million of net gains on its derivative commodity instruments reflected in accumulated OCI, net of tax, as of December 31, 2015 will be recognized in earnings during the next twelve months due to the settlement of hedged transactions. As a result of the discontinuance of cash flow hedge accounting, beginning in 2015, all changes in fair value of the Company's derivative instruments are recognized within operating revenues in the Statements of Consolidated Income.

The Company also enters into fixed price natural gas sales agreements that are satisfied by physical delivery. These physical commodity contracts qualify for the normal purchases and sales exception and are not subject to derivative instrument accounting.

Exchange-traded instruments are generally settled with offsetting positions. OTC arrangements require settlement in cash. Settlements of derivative commodity instruments are reported as a component of cash flows from operations in the accompanying Statements of Consolidated Cash Flows.

	Years Ended December 31,		
	2015	2014	2013
		(Thousands)	
Commodity derivatives designated as cash flow hedges			
Amount of gain recognized in OCI (effective portion), net of tax	$ —	$ 156,207	$ 10,669
Amount of gain reclassified from accumulated OCI, net of tax, into gain on sale / exchange of assets and dispositions due to forecasted transactions probable to not occur	—	16,735	—
Amount of gain (loss) reclassified from accumulated OCI, net of tax, into operating revenues (effective portion)	152,359	(15,950)	87,158
Amount of gain (loss) recognized in operating revenues (ineffective portion) (a)	—	24,774	(21,335)
Interest rate derivatives designated as cash flow hedges			
Amount of loss reclassified from accumulated OCI, net of tax, into interest expense (effective portion)	$ (144)	$ (145)	$ (144)
Commodity derivatives designated as fair value hedges (b)			
Amount of loss recognized in operating revenues for fair value commodity contracts	$ —	$ —	$ (1,341)
Fair value gain recognized in operating revenues for inventory designated as hedged item	—	—	386
Derivatives not designated as hedging instruments			
Amount of gain recognized in operating revenues	$ 385,762	$ 80,942	$ 2,834

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

(b) For the year ended December 31, 2013, the net impact on operating revenues consisted of a $0.5 million gain due to the exclusion of the spot/forward differential from the assessment of effectiveness and a $1.5 million loss due to changes in basis.

The absolute quantities of the Company's derivative commodity instruments totaled 676 Bcf and 624 Bcf as of December 31, 2015 and 2014, respectively, and were primarily related to natural gas swaps, basis swaps and collars. The open positions at December 31, 2015 and 2014 had maturities extending through December 2019 and 2018, 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, 2015 or 2014.

When the Company enters into exchange-traded natural gas contracts, exchanges may require the Company to remit funds to the corresponding broker as good-faith deposits to guard against the risks associated with changing market conditions. The Company must make such deposits based on an established initial margin requirement as well as the net liability position, if any, of the fair value of the associated contracts. The Company records these deposits as a current asset in the Consolidated Balance Sheets. In the case where the fair value of such contracts is in a net asset position, the broker may remit funds to the Company, in which case the Company records a current liability for such amounts received. The initial margin requirements are established by the exchanges based on the price, volatility and the time to expiration of the related contract. The margin requirements are subject to change at the exchanges' discretion. The Company had no such deposits in its Consolidated Balance Sheets as of December 31, 2015. The Company recorded current assets of $0.1 million as of December 31, 2014 for such deposits in its Consolidated Balance Sheets.

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, 2015 and 2014.

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

As of December 31, 2014	**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	$ 458,460	$ (22,810)	$ —	$ 435,650
Liability derivatives:				
Derivative instruments, at fair value	$ 22,942	$ (22,810)	$ (132)	$ —

Certain of the Company's derivative instrument contracts provide that if the Company's credit ratings by Standard & Poor's Rating Services (S&P) or Moody's Investor Services (Moody's) are lowered below investment grade, additional collateral must be deposited with the counterparty. The additional collateral can be up to 100% of the derivative liability. As of December 31, 2015, the aggregate fair value of all derivative instruments with credit risk-related contingent features that were in a net liability position was $4.8 million, for which the Company had no collateral posted on December 31, 2015. If the Company's credit rating by S&P or Moody's had been downgraded below investment grade on December 31, 2015, the Company would not have been required to post any additional collateral under the agreements with the respective counterparties. Investment grade refers to the quality of the Company's credit as assessed by one or more credit rating agencies. The Company's senior unsecured debt was rated BBB by S&P and Baa3 by Moody's at December 31, 2015. On December 16, 2015, Moody's announced that it had placed 29 U.S. exploration and production companies, including the Company, under review for a downgrade due to the low commodity price environment. In order to be considered investment grade, the Company must be rated BBB- or higher by S&P and Baa3 or higher by Moody's. Anything below these ratings is considered non-investment grade. Having a non-investment grade rating would result in greater borrowing costs and collateral requirements than would be available if all credit ratings were investment grade.

7. Fair Value Measurements

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

The Company has categorized its assets and liabilities recorded at fair value into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities included in Level 1 include the Company's futures contracts. Assets and liabilities in Level 2 primarily include the Company's swap and collar agreements. There were no transfers between Level 1 and 2 during the periods presented. There were no transfers into or out of Level 3 during the periods presented. The Company recognizes transfers between Levels as of the actual date of the event or change in circumstances that caused the transfer.

The fair value of the assets and liabilities included in Level 2 is based on standard industry income approach models that use significant observable inputs, including New York Mercantile Exchange (NYMEX) forward curves, LIBOR-based discount rates and basis forward curves. The Company's collars and options are valued using standard industry income approach option models. The significant observable inputs utilized by the option pricing models include NYMEX forward curves, natural gas volatilities and LIBOR-based discount rates.

The Company uses NYMEX forward curves to value futures, commodity swaps and collars. The NYMEX 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	**December 31, 2015**	**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	$ 417,397	$ —	$ 417,397	$ —
Liabilities				
Derivative instruments, at fair value	$ 23,434	$ —	$ 23,434	$ —

		Fair value measurements at reporting date using		
Description	**December 31, 2014**	**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	$ 458,460	$ —	$ 458,460	$ —
Liabilities				
Derivative instruments, at fair value	$ 22,942	$ 132	$ 22,810	$ —

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

The Company estimates the fair value of its debt using its established fair value methodology. Because not all of the Company’s debt is actively traded, the fair value of the debt is a Level 2 fair value measurement. Fair value for non-traded debt obligations is estimated using a standard industry income approach model which utilizes a discount rate based on market rates for debt with similar remaining time to maturity and credit risk. The estimated fair value of total debt (including EQM’s long-term debt) on the Consolidated Balance Sheets at December 31, 2015 and 2014 was approximately $2.8 billion and $3.3 billion, respectively. The carrying value of total debt (including EQM's long-term debt) on the Consolidated Balance Sheets at December 31, 2015 and 2014 was approximately $2.8 billion and $3.0 billion, respectively. Refer to Note 13 for further information regarding the Company's debt as of December 31, 2015 and 2014.

For information on the fair values of assets related to the impairment of proved and unproved oil and gas properties, assets acquired in the Range exchange, the assets acquired in the Chesapeake acquisition and the assets related to the defined benefit pension plan assets, see Notes 1, 8, 9 and Note 14, respectively.

8. Sales of Properties and Contracts

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

On December 31, 2013, the Company sold certain energy marketing contracts to a third party for $20.0 million. These contracts were natural gas sales agreements with approximately 1,000 customers with total volumes of approximately 12 Bcf in 2013. The Company received $18.0 million of cash on December 31, 2013 and the remaining $2.0 million in 2014. In conjunction with this transaction, the Company realized a pre-tax gain of $19.6 million in 2013.

Assets acquired as part of the Equitable Gas Transaction included energy marketing contracts with approximately 50 customers valued at $5.0 million. On December 31, 2013, the Company sold these contracts to a third party for $5.0 million, which was received on December 31, 2013.

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

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

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

9. Acquisitions

In June 2013, the Company acquired approximately 99,000 net acres in southwestern Pennsylvania and ten horizontal Marcellus wells, located in Washington County, Pennsylvania, from Chesapeake Energy Corporation and its partners (Chesapeake) for approximately $114.2 million. The acreage included 67,000 Marcellus acres, of which 42,000 acres were unlikely to be developed due to near-term lease expirations or a scattered footprint. Of the total purchase price, $57.2 million was allocated to the undeveloped acreage and $57.0 million was allocated to the acquired Marcellus wells.

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

10. Income Taxes

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

	Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Current:			
Federal	$ 85,696	$ 164,935	$ 100,796
State	1,103	17,136	46,758
Subtotal	86,799	182,071	147,554
Deferred:			
Federal	(109,642)	38,357	51,767
State	127,518	(6,336)	(23,940)
Subtotal	17,876	32,021	27,827
Amortization of deferred investment tax credit	—	—	(195)
Total income taxes	$ 104,675	$ 214,092	$ 175,186

The current federal and state income tax expense primarily relates to federal alternative minimum tax (AMT) due to tax gains generated as a result of the net proceeds received from EQGP's IPO and the NWV Gathering Transaction in 2015, the Jupiter Transaction in 2014 and the merger of Sunrise Pipeline, LLC with and into Equitrans, L.P., an indirect wholly owned subsidiary of EQM (Equitrans), in 2013 (Sunrise Merger) as well as the Equitable Gas Transaction.

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

In 2013, the Commonwealth of Pennsylvania adopted multiple changes to the Commonwealth's tax code, including an intangible expense addback provision effective in 2015, an increase of the cap on the net operating loss (NOL) deduction in 2014 and 2015 and an extension of the franchise tax through 2015. The impact of this law change has been reflected in the Company's financial statements.

In September 2013, the United States Treasury Department issued final regulations regarding the deduction and capitalization of expenditures related to tangible property and proposed regulations addressing the disposition of tangible property. These regulations do not address the tax treatment for network assets such as natural gas pipelines; however, they do replace previously issued temporary regulations and are effective for tax years beginning January 1, 2014. The Company performed an analysis of the regulations and concluded that they have no significant impact on its financial statements.

The Company utilized its remaining NOLs for federal tax purposes in 2014 and 2013, given the increase in current taxable income, and no longer has any federal NOLs available as of December 31, 2015. For federal income tax purposes, the Company deducts a portion of drilling costs as intangible drilling costs (IDCs) in the year incurred which allows the Company to minimize such tax. IDCs, however, are sometimes limited for AMT purposes which can result in the Company paying AMT despite the fact that taxable income has been fully offset by current tax deductions or NOL carryforwards.

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

	Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Tax at statutory rate	$ 149,296	$ 253,299	$ 182,406
State income taxes	(7,566)	(2,992)	26,012
Valuation allowance	91,144	10,012	(9,832)
Noncontrolling partners' share of EQGP and EQM earnings	(82,850)	(43,409)	(16,535)
Regulatory asset	(35,438)	—	—
Research and experimentation credit	(7,243)	(468)	(375)
Other	(2,668)	(2,350)	(6,490)
Income tax expense	$ 104,675	$ 214,092	$ 175,186
Effective tax rate	24.5%	29.6%	33.6%

The Company's effective tax rate for the year ended December 31, 2015 was 24.5% compared to 29.6% for the year ended December 31, 2014. The decrease in the rate from 2014 to 2015 was primarily due to an increase in earnings allocated to noncontrolling limited partners of EQGP and EQM, the effects of the Internal Revenue Service (IRS) guidance (which is further discussed below), a decrease in EQT Production's operating income, increased tax credits in 2015 and a decrease in state taxes in 2015 as a result of lower pre-tax income on state income tax paying entities. These decreases were significantly offset by an increase in the valuation allowance recorded primarily on Pennsylvania state NOLs. The increase to noncontrolling limited partners income was primarily the result of higher net income at EQM and increased noncontrolling interests as a result of EQM's March and November 2015 public offerings of common units, issuances of EQM common units under the $750 million ATM Program and EQGP's IPO. The Company consolidates 100% of the pre-tax income related to the noncontrolling limited partners' share of EQGP earnings but is not required to record an income tax provision with respect to the portion of the earnings allocated to the EQM and EQGP noncontrolling limited partners.

For the year ended December 31, 2015, the Company realized a $35.4 million tax benefit in connection with recent IRS guidance received by the Company regarding the Company's sale of Equitable Gas, a regulated entity, in 2013. The transaction included a partial like-kind exchange of assets that resulted in tax deferral for the Company. However, in order to be in compliance with the normalization rules of the Internal Revenue Code, the IRS guidance held that the deferred tax liability associated with the exchanged regulatory assets should not be considered for ratemaking purposes. As a result, during the second quarter of 2015, the Company recorded a regulatory asset equal to the taxes deferred from the exchange and an associated income tax benefit. The regulatory asset and deferred taxes will be reversed when the assets are disposed of in a taxable transaction such as a sale of assets or amortized over the 32 years remaining life of the assets received in the exchange, in either event increasing tax expense at that time.

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

The Company's effective tax rate for the year ended December 31, 2014 was 29.6% compared to 33.6% for the year ended December 31, 2013. The decrease in the rate from 2013 to 2014 was primarily due to an internal reorganization of subsidiaries resulting in a reduction to state taxes as well as an increase in EQM earnings and the noncontrolling public limited partners' share of EQM earnings as a result of the Sunrise Merger and Jupiter Transaction.

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

	2015	2014	2013
		(Thousands)	
Balance at January 1	$ 56,957	$ 57,087	$ 17,858
Additions based on tax positions related to current year	152,983	1,195	49,289
Additions for tax positions of prior years	50,688	93	—
Reductions for tax positions of prior years	(1,327)	(1,418)	(790)
Lapse of statute of limitations	—	—	(9,270)
Balance at December 31	$ 259,301	$ 56,957	$ 57,087

Included in the balance are unrecognized tax benefits (excluding interest and penalties) that, if recognized, would affect the effective tax rate of $94.1 million, $33.9 million and $33.3 million as of December 31, 2015, 2014 and 2013, respectively. Additionally, there are uncertain tax positions of $114.2 million, $10.1 million, and $9.8 million for the years ended December 31, 2015, 2014 and 2013, respectively, that are included in the tabular reconciliation above, but recorded in the Consolidated Balance Sheets as a reduction of the related deferred tax asset for AMT credit carryforwards and NOLs.

Included in the tabular reconciliation above at December 31, 2015, 2014 and 2013 are $6.4 million, $6.9 million and $7.6 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. Because of the impact of deferred tax accounting, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash taxes to an earlier period.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company recorded approximately $1.6 million and $1.9 million for 2015 and 2014, respectively, and reversed $0.4 million of previously recorded interest expense in 2013. Interest and penalties of $3.6 million, $2.0 million and $0.2 million were included in the balance sheet reserve at December 31, 2015, 2014 and 2013, respectively.

As of December 31, 2015, the Company does not expect any of its unrecognized tax benefits to decrease within the next 12 months due to potential settlements with taxing authorities, legal or administrative guidance by relevant taxing authorities or the lapse of applicable statutes of limitation.

The consolidated federal income tax liability of the Company has been settled with the IRS through 2009. The IRS has completed its review of the 2010 and 2011 tax years and the Company is in the process of appealing its R&E tax credit claim for such years. The IRS review of the Company's 2012 tax year has commenced. The Company also is the subject of various state income tax examinations. With few exceptions, as of December 31, 2015, 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 unrecognized tax benefits during 2015.

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, 2015	As of December 31, 2014
	(Thousands)	
Deferred income taxes:		
Total deferred income tax assets	$ (827,161)	$ (971,531)
Total deferred income tax liabilities	2,799,331	2,700,467
Total net deferred income tax liabilities	1,972,170	1,728,936
Total deferred income tax liabilities (assets)		
Drilling and development costs expensed for income tax reporting	1,421,581	1,391,156
Tax depreciation in excess of book depreciation	1,224,377	1,154,082
Accumulated OCI	29,154	130,770
Post-retirement benefits	3,326	3,146
Incentive compensation and deferred compensation plans	(75,143)	(65,086)
Net operating loss carryforwards	(214,714)	(212,718)
Investment in EQGP and EQM	(426,343)	(336,394)
Alternative minimum tax credit carryforward	(267,045)	(412,345)
Unrealized hedge gains	107,854	21,314
Other	13,039	(9,976)
Total excluding valuation allowances	1,816,086	1,663,949
Valuation allowance	156,084	64,987
Total (including amounts classified as current assets of $21,934 in 2014)	$ 1,972,170	$ 1,728,936

The net deferred tax liability relating to the Company's accumulated OCI balance as of December 31, 2015 consisted of a $40.2 million deferred tax liability related to the Company's net unrealized gain from hedging transactions, a $4.9 million deferred tax asset related to other post-retirement benefits, and a $6.1 million deferred tax asset related to the Company's pension plans. The net deferred tax liability relating to the Company's accumulated OCI balance as of December 31, 2014 consisted of a $141.3 million deferred tax liability related to the Company's net unrealized gain from hedging transactions, a $5.4 million deferred tax asset related to other post-retirement benefits, and a $5.1 million deferred tax asset related to the Company's pension plans.

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

As of December 31, 2015, the Company had a deferred tax asset of $90.3 million, net of valuation allowances of $156.1 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2018 to 2035. As of December 31, 2014, the Company had a deferred tax asset of $116.0 million, net of valuation allowances of $65.0 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2018 to 2034. The deferred tax asset has been reduced for uncertain tax positions of approximately $31.7 million and $0.3 million during the years ended December 31, 2015 and 2014, respectively. Management will continue to assess the potential for realizing deferred tax assets based upon income forecast data and the feasibility of future tax planning strategies and may record adjustments to valuation allowances against deferred tax assets in future periods, as appropriate, that could materially impact net income.

Historically, excess tax benefits were not recorded in the Company's financial statements as an addition to common stockholders' equity due to the Company's NOL position. As the Company generated taxable income in the years ended December 31, 2015 and 2014, resulting in a corresponding ability to realize a benefit from these amounts, the Company recorded tax benefits of $13.1 million and $26.6 million as of December 31, 2015 and 2014, respectively, in the financial statements as an addition to common stockholders' equity as these tax benefits reduced taxes payable in the current year. In 2015, the Company also recorded tax benefits of $8.1 million for the 2012 excess tax benefits previously not recorded since the Company fully utilized the 2012 NOL during 2015. In 2014, the Company recorded tax benefits of $6.6 million for the 2011 excess tax benefits previously not recorded since the Company fully utilized the 2011 NOL during 2014. The Company uses tax law ordering when determining when excess tax benefits have been realized.

11. Equity in Nonconsolidated Investments

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

Investees	Location	Interest Type	Ownership as of December 31, 2015 (a)	As of December 31, 2015	2014
				(Thousands)	
MVP Joint Venture	USA	Joint	54%	$ 77,025	$ —

(a) As of February 11, 2016, EQM owned a 45.5% ownership interest in the MVP Joint Venture. See Note 4.

The Company's ownership share of the earnings for 2015, 2014 and 2013 related to the total investments accounted for under the equity method was $2.6 million, $3.4 million and $7.6 million, respectively, reported in other income on the Statements of Consolidated Income. For the year ended December 31, 2015, the Company's ownership share of the earnings included equity earnings related to the Company's equity investment in the MVP Joint Venture. For the years ended December 31, 2014 and 2013, the Company's ownership share of the earnings included equity earnings related to the Company's equity investment in Nora LLC. See Note 8 for further details regarding the Company's disposition of its interest in Nora LLC.

EQM's equity investment in the MVP Joint Venture represented a 54% ownership interest as of December 31, 2015. In the first quarter of 2015, the Company assigned 100% of the membership interests in MVP Holdco, an indirect wholly owned subsidiary of the Company that owns an interest in the MVP Joint Venture, to EQM. The MVP Joint Venture plans to construct the MVP, an estimated 300-mile natural gas interstate pipeline spanning from northern West Virginia to southern Virginia. The MVP Joint Venture has been determined to be a variable interest entity because the MVP Joint Venture has insufficient equity to finance activities during the construction stage of the project. EQM is not the primary beneficiary because it does not have the power to direct the activities of the MVP Joint Venture that most significantly impact its economic performance. Certain business decisions, including, but not limited to, decisions with respect to operating and construction budgets, project construction schedule, material contracts or precedent agreements, indebtedness, significant acquisitions or dispositions, material regulatory filings and strategic decisions require the approval of owners holding more than a 66 2/3% interest in the MVP Joint Venture and no one member owns more than a 66 2/3% interest. Beginning on the date it was assumed from the Company, EQM accounted for the MVP Interest as an equity method investment as EQM has the ability to exercise significant influence over operating and financial policies of the MVP Joint Venture. As of December 31, 2015, the Company's interest in the MVP Joint Venture was recorded in other assets on the Consolidated Balance Sheets.

On January 21, 2016, affiliates of ConEd acquired a 12.5% interest in the MVP Joint Venture, 8.5% of which was purchased from EQM. EQM received cash payments of $12.5 million which was equal to EQM's proportional capital contributions to the MVP Joint Venture through the date of the transaction. As of February 11, 2016, EQM owned a 45.5% ownership interest in the MVP Joint Venture. ConEd has the right to terminate its purchase of the interest in the MVP Joint Venture and be reimbursed for the purchase price and all capital contributions made to the MVP Joint Venture for a period ending no later than December 31, 2016.

As of December 31, 2015, EQM had issued a $108 million performance guarantee in favor of the MVP Joint Venture to provide performance assurances for MVP Holdco's obligations to fund its proportionate share of the construction budget for the MVP. Upon the FERC's initial release to begin construction of the MVP, EQM's guarantee will terminate, and EQM will be obligated to issue a new guarantee in an amount equal to 33% of MVP Holdco's remaining obligations to make capital contributions to the MVP Joint Venture in connection with the then remaining construction budget, less any credit assurances issued by any affiliate of EQM under such affiliate's precedent agreement with the MVP Joint Venture. As a result of the ConEd Transaction, the amount of the Initial EQM Guarantee decreased to $91 million as of February 11, 2016.

EQM's maximum financial statement exposure related to the MVP Joint Venture was approximately $185 million, which includes the investment balance of $77 million on the Consolidated Balance Sheet as of December 31, 2015 and amounts which could have become due under the performance guarantee as of that date.

The following table summarizes the unaudited condensed financial statements for nonconsolidated investments accounted for under the equity method of accounting for the periods noted (including MVP Joint Venture for 2015 and Nora LLC for 2014 and 2013):

Summarized Statements of Income

	Years Ended December 31,		
	2015	2014	2013
		(Thousands)	
Revenues	$ —	$ 19,924	$ 45,040
Operating expenses	—	13,257	29,892
Other income	2,566	102	82
Net income	$ 2,566	$ 6,769	$ 15,230

12. Revolving Credit Facilities

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

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

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

EQM has a $750 million credit facility that expires in February 2019. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions and repurchase units and for general partnership purposes. Provided there exists no default, and subject to certain terms and conditions, EQM may request that the lenders' commitments be increased to an aggregate amount up to $1.0 billion. Each lender in the facility may decide if it will increase its commitment. The credit facility is underwritten by a syndicate of 18 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by EQM. The Company is not a guarantor of EQM's obligations under the credit facility. EQM's obligations under the revolving portion of the credit facility are unsecured. EQM's obligations under the credit facility were unconditionally guaranteed by each of EQM's subsidiaries. In January 2015, EQM amended its credit facility to, among other things, release its subsidiaries from their guarantee obligations under the credit facility.

The Company had no borrowings or letters of credit outstanding under its revolving credit facility as of December 31, 2015 or 2014 or at any time during the years ended December 31, 2015 or 2014. The Company incurred commitment fees averaging approximately 23 basis points for the years ended December 31, 2015 and 2014 to maintain credit availability under its credit facility.

As of December 31, 2015, EQM had $299 million of borrowings and no letters of credit outstanding under its revolving credit facility. As of December 31, 2014, EQM had no borrowings or letters of credit outstanding under its revolving credit facility. The maximum amount of outstanding borrowings under EQM's revolving credit facility at any time during the years ended December 31, 2015 and 2014 was $404 million and $450 million, respectively. The average daily balance of loans outstanding under EQM's credit facility was $261 million and $119 million during the years ended December 31, 2015 and 2014, respectively. Interest was incurred on the borrowings at a weighted average annual interest rate of approximately 1.7% for the years ended December 31, 2015 and 2014, respectively. EQM incurred commitment fees averaging approximately 23 basis points and 24 basis points for the years ended December 31, 2015 and 2014, respectively, to maintain credit availability under its credit facility.

The $299 million of borrowings under EQM's credit facility at December 31, 2015 were repaid on February 8, 2016.

The Company's credit facility contains various provisions that, if not complied with, could result in termination of the credit facility, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the Company's credit facility relate to maintenance of a debt-to-total capitalization ratio and limitations on transactions with affiliates. The Company's credit facility contains financial covenants that require a total debt-to-total capitalization ratio of no greater than 65%. The calculation of this ratio excludes the effects of accumulated OCI. As of December 31, 2015, the Company was in compliance with all debt provisions and covenants.

EQM's credit facility contains various provisions that, if not complied with, could result in termination of the credit facility, require early payment of amounts outstanding or similar actions. The covenants and events of default under the credit facility relate to maintenance of permitted leverage ratio, limitations on transactions with affiliates, limitations on restricted payments, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of and certain other defaults under other financial obligations and change of control provisions. Under EQM's credit facility, EQM is required to maintain a consolidated 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, 2015, EQM was in compliance with all debt provisions and covenants.

13. Long-Term Debt

	December 31, 2015			December 31, 2014		
	Principal Value	Carrying Value (a)	Fair Value (b)	Principal Value	Carrying Value (a)	Fair Value (b)
	(Thousands)					
7.76% notes, due 2015 through 2016	$ —	$ —	$ —	$ 10,700	$ 10,700	$ 10,700
5.00% notes, due October 1, 2015	—	—	—	150,000	149,865	154,692
5.15% notes, due March 1, 2018	200,000	199,156	203,490	200,000	198,766	214,626
6.50% notes, due April 1, 2018	500,000	498,360	520,175	500,000	497,630	559,900
8.13% notes, due June 1, 2019	700,000	697,295	760,837	700,000	696,483	843,864
4.88% notes, due November 15, 2021	750,000	742,270	728,063	750,000	740,945	812,558
4.00% EQM notes, due August 1, 2024	500,000	493,401	414,125	500,000	492,633	495,685
7.75% debentures, due July 15, 2026	115,000	109,738	119,372	115,000	109,240	147,036
Medium-term notes:						
7.3% to 7.6% Series B, due 2015 through 2023	10,000	9,991	10,241	20,000	19,985	22,279
7.6% Series C, due 2018	8,000	7,983	8,366	8,000	7,975	8,950
8.7% to 9.0% Series A, due 2020 through 2021	35,200	35,149	38,598	35,200	35,131	43,912
	2,818,200	2,793,343	2,803,267	2,988,900	2,959,353	3,314,202
Less debt payable within one year	—	—	—	166,011	165,874	171,081
Total long-term debt	$ 2,818,200	$ 2,793,343	$ 2,803,267	$ 2,822,889	$ 2,793,479	$ 3,143,121

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

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

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

Aggregate maturities of long-term debt are zero in 2016, zero in 2017, $708.0 million in 2018, $700.0 million in 2019, and $11.2 million in 2020.

14. 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. Distribution of plan assets pursuant to the termination will not be made until the plan termination satisfies all regulatory requirements, including required filings with the IRS and the Pension Benefit Guaranty Corporation (PBGC). On May 12, 2015, a determination letter request for the Retirement Plan was filed with the IRS. On January 4, 2016, the Company received a letter from the IRS, dated December 29, 2015, requesting additional information in connection with the determination letter filing, which the Company responded to on January 25, 2016. On June 5, 2015 (received by the PBGC on June 8, 2015), the Retirement Plan termination was filed for review by the PBGC. The PBGC 60-day review period expired without further response from the PBGC on August 8, 2015. Accordingly, the Company may proceed with the termination. The termination process is expected to be complete by the end of 2016. The Company will fully fund the Retirement Plan and then satisfy all of the benefit obligations under the Retirement Plan by purchasing one or more annuities for participants from an insurance company or other financial institution. All assets of the Retirement Plan are expected to be liquidated and used to purchase annuities, and all non-cash unrecognized losses are expected to be recognized, by the end of 2016.

The following table sets forth the defined benefit pension and other post-retirement benefit plans' funded status and amounts recognized for those plans in the Company's Consolidated Balance Sheets. Refer to Note 2 for further information related to the Equitable Gas Transaction.

	For the Years Ended December 31,			
	2015	2014	2015	2014
	Pension Benefits		Other Benefits	
	(Thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 21,704	$ 21,828	$ 18,741	$ 18,253
Service cost	350	350	762	669
Interest cost	746	820	634	693
Amendments	—	—	—	227
Actuarial loss (gain)	2,770	2,412	(361)	1,190
Benefits paid	(1,981)	(1,988)	(2,141)	(2,291)
Expenses paid	(367)	(262)	—	—
Settlements	(177)	(1,456)	—	—
Benefit obligation at end of year	$ 23,045	$ 21,704	$ 17,635	$ 18,741
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 18,323	$ 20,089	$ 823	$ 493
Actual (loss) gain on plan assets	(32)	1,217	—	—
Contributions	1,175	723	287	330
Benefits paid	(1,981)	(1,988)	—	—
Expenses paid	(367)	(262)	—	—
Settlements	(177)	(1,456)	—	—
Fair value of plan assets at end of year	16,941	18,323	1,110	823
Funded status at end of year	$ (6,104)	$ (3,381)	$ (16,525)	$ (17,918)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$ (6,104)	$ —	$ (1,376)	$ (924)
Noncurrent liabilities	—	(3,381)	(15,149)	(16,994)
Net amounts recognized	$ (6,104)	$ (3,381)	$ (16,525)	$ (17,918)
Amounts recognized in accumulated OCI, net of tax, consist of:				
Net loss	$ 9,674	$ 8,082	$ 7,610	$ 8,273
Net prior service	—	—	257	285
Net amount recognized	$ 9,674	$ 8,082	$ 7,867	$ 8,558

The accumulated benefit obligation for the Company's defined benefit pension plan was approximately $23.0 million and $21.7 million at December 31, 2015 and 2014, respectively. The Company uses a December 31 measurement date for its defined benefit pension and other post-retirement benefit plans.

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

	For the Years Ended December 31,					
	2015	2014	2013	2015	2014	2013
	Pension Benefits			Other Benefits		
	(Thousands)					
Components of net periodic benefit cost:						
Service cost	$ 350	$ 350	$ 500	$ 762	$ 669	$ 905
Interest cost	746	820	1,935	634	693	1,110
Expected return on plan assets	(627)	(1,377)	(3,323)	—	—	—
Amortization of prior service cost	—	—	—	(306)	(446)	(845)
Recognized net actuarial loss	746	709	2,306	793	879	1,760
Settlement loss and special termination benefits	122	879	381	—	—	—
Subtotal	1,337	1,381	1,799	1,883	1,795	2,930
Net periodic benefit cost of discontinued operations	—	—	1,552	—	—	1,356
Net periodic benefit cost	$ 1,337	$ 1,381	$ 247	$ 1,883	$ 1,795	$ 1,574

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 its rate-regulated EQT Midstream business.

	For the Years Ended December 31,					
	2015	2014	2013	2015	2014	2013
	Pension Benefits			Other Benefits		
	(Thousands)					
Other changes in plan assets and benefit obligations recognized in OCI, net of tax:						
Net loss (gain)	$ 1,592	$ 558	$ 712	$ (663)	$ 39	$ 2,147
Net prior service (credit) cost	—	—	—	(28)	179	416
Total recognized in OCI, net of tax	$ 1,592	$ 558	$ 712	$ (691)	$ 218	$ 2,563
Total recognized in net periodic benefit cost and OCI, net of tax	$ 2,929	$ 1,939	$ 959	$ 1,192	$ 2,013	$ 4,137

The net loss and prior service cost associated with the disposal group of the Equitable Gas Transaction totaled $17.3 million, net of tax, at the closing date of the Equitable Gas Transaction. The Company recognized the full amount in income from discontinued operations in the Statements of Consolidated Income for the year ended December 31, 2013.

The estimated net loss for the defined benefit pension plan that will be amortized from accumulated OCI, net of tax, into net periodic benefit cost during 2016 is $0.1 million; in addition, the remaining $9.5 million will be recognized upon final settlement of the plan. The estimated net loss and net prior service (credit) for the other post-retirement benefit plans that will be amortized from accumulated OCI, net of tax, into net periodic benefit cost during 2016 are $0.4 million and $(0.2) million, respectively.

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

	December 31,			
	2015	2014	2015	2014
	Pension Benefits		Other Benefits	
Discount rate	2.20%	3.60%	3.95%	3.60%
Rate of compensation increase	N/A	N/A	N/A	N/A

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

	For the Years Ended December 31,			
	2015	2014	2015	2014
	Pension Benefits		Other Benefits	
Discount rate	3.60%	4.00%	3.60%	4.00%
Expected return on plan assets	3.75%	7.75%	N/A	N/A
Rate of compensation increase	N/A	N/A	N/A	N/A

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

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits in 2015 was 7.00% for both the Pre-65 and Post-65 medical charges. The rates were assumed to decrease gradually to ultimate rates of 5.00% in 2025.

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

	One-Percentage-Point Increase			One-Percentage-Point Decrease		
	2015	2014	2013	2015	2014	2013
	(Thousands)					
Increase (decrease) to total of service and interest cost components	$ 10	$ 13	$ 25	$ (11)	$ (14)	$ (26)
Increase (decrease) to post-retirement benefit obligation	$ 268	$ 228	$ 220	$ (278)	$ (229)	$ (223)

The Company's asset allocation for the Retirement Plan at December 31, 2015 and 2014 and target allocation for 2016 by asset category are as follows:

Asset Category	Target Allocation 2016	Percentage of Plan Assets at December 31, 2015	2014
Domestic broadly diversified equity securities	0% - 10%	—%	26%
Fixed income securities	80% - 100%	99%	63%
International broadly diversified equity securities	0%	—%	8%
Cash and equivalent investments	0% - 20%	1%	3%
		100%	100%

The investment activities of the Retirement Plan are supervised and monitored by the Benefits Investment Committee (BIC). The BIC reports to the Management Development and Compensation Committee (the Compensation Committee) of the Board of Directors and consists of the chief financial officer and other officers and employees of the Company. Prior to the Company's determination to terminate the Retirement Plan in 2014, the BIC had developed an investment strategy that focused on asset allocation, diversification and quality guidelines. The investment goals of the BIC were to minimize high levels of risk at the total pension investment fund level.

In October 2014 in anticipation of the termination of the Retirement Plan, the BIC modified the investment allocations for the Retirement Plan by allocating a greater portion of the plan assets to fixed income securities to prepare for the expected liquidation of plan assets. As a result of the modification of the investment allocations, at December 31, 2014 the fixed income securities and domestic diversified equity securities categories were outside of the previously established target allocations but consistent with the BIC's October 2014 determination.

In February 2015, the BIC decided to sell the remaining equity investments and invested the funds in fixed-income investments with similar duration to the plan liabilities. The reallocation was completed by March 31, 2015, and the Retirement Plan's assets now consist of only fixed-income investments and cash and cash equivalents.

The BIC monitors the asset allocation on a quarterly basis and makes adjustments, as needed, to rebalance the assets to the desired allocation. Comparative market and peer group benchmarks are utilized to ensure that each of the investment managers is performing satisfactorily.

The Company made cash contributions to the Retirement Plan of approximately $1.2 million, $0.7 million and $2.6 million during 2015, 2014 and 2013, respectively, to meet certain funding targets. Assuming the termination process for the Retirement Plan is completed in 2016 as anticipated, the Company expects to make cash payments of $6.1 million during 2016 to fully fund the Retirement Plan and purchase the required annuities, make other cash settlements and pay any administrative expenses of the termination. The Company does not expect its cash contributions to have a significant effect on its financial position, results of operations or liquidity.

All assets of the Retirement Plan are expected to be liquidated in the termination and used, together with the Company's 2016 cash contribution to purchase annuities for participants of approximately $22.9 million from an insurance company or other financial institution.

The following benefit payments for post-retirement benefits other than pensions, which reflect expected future service, are expected to be paid by the Company during each of the next five years and the five years thereafter: $1.7 million in 2016; $1.7 million in 2017; $1.6 million in 2018; $1.6 million in 2019; $1.6 million in 2020; and $7.1 million in the five years thereafter.

Expense recognized by the Company related to its defined contribution plan totaled $15.7 million in 2015, $13.7 million in 2014 and $14.6 million in 2013.

The Company reports defined benefit plan assets at fair value which is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The disclosure below categorizes the assets by a fair value hierarchy. Assets and liabilities are classified in their entirety based on the lowest level of input significant to the fair value measurement. The three levels of the hierarchy are defined as follows:

Level 1 – Observable inputs based on quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 – Observable inputs, other than those included in Level 1, based on quoted prices for similar assets or liabilities in active markets or quoted prices for identical assets and liabilities in inactive markets.

Level 3 – Unobservable inputs that reflect an entity's own assumptions about what inputs a market participant would use in pricing the asset or liability based on the best information available in the circumstances.

Defined benefit plan asset investments included cash equivalents and fixed income securities with a fair value of $5.4 million and $5.7 million as of December 31, 2015 and 2014, respectively. These investments are based upon daily unadjusted quoted prices and therefore are considered Level 1.

Defined benefit plan asset investments also include common/collective trusts and fixed income securities with a fair value of $11.3 million and $12.6 million as of December 31, 2015 and 2014, respectively. These investments are valued at current market value of the underlying assets of the fund and therefore are considered Level 2.

As of December 31, 2015 and 2014, the Retirement Plan did not hold any assets whose fair value was determined using unobservable inputs and therefore would be considered Level 3.

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15. 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, 2015, 2014, and 2013:

	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 January 1, 2015	$	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

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

	Year Ended December 31, 2013										
	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 January 1, 2013	$	138,188		$	(1,276)		$	(37,365)		$	99,547
Gains recognized in accumulated OCI, net of tax		10,669	(a)		—			2,081			12,750
(Gains) losses reclassified from accumulated OCI, net of tax		(87,158)	(a)		144	(a)		19,420	(b)		(67,594)
Change in accumulated OCI, net of tax		(76,489)			144			21,501			(54,844)
Accumulated OCI (loss), net of tax, as of December 31, 2013	$	61,699		$	(1,132)		$	(15,864)		$	44,703

(a) See Note 6 for additional information.

(b) This accumulated OCI reclassification is attributable to the net actuarial loss and net prior service cost related to the Company's defined benefit pension plans and other post-retirement benefit plans. See Note 14 for additional information.

16. Common Stock, Treasury Stock and Earnings Per Share

Common Stock

At December 31, 2015, shares of EQT's authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	20,457
Stock compensation plans	13,394
Total	33,851

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. Shares of the Company's common stock held by the rabbi trust are accounted for as treasury stock in the Company's financial statements.

Earnings Per Share

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

	Years Ended December 31,		
	2015	2014	2013
	(Thousands except per share amounts)		
Basic earnings per common share:			
Net income attributable to EQT Corporation	$ 85,171	$ 386,965	$ 390,572
Average common shares outstanding	152,398	151,553	150,574
Basic earnings per common share	$ 0.56	$ 2.55	$ 2.59
Diluted earnings per common share:			
Net income attributable to EQT Corporation	$ 85,171	$ 386,965	$ 390,572
Average common shares outstanding	152,398	151,553	150,574
Potentially dilutive securities:			
Stock options and awards (a)	541	960	1,213
Total	152,939	152,513	151,787
Diluted earnings per common share	$ 0.56	$ 2.54	$ 2.57

(a) Options to purchase common stock which were excluded from potentially dilutive securities because they were anti-dilutive totaled 291,700 shares for the year ended December 31, 2015. There were no options to purchase common stock which were excluded from potentially dilutive securities because they were anti-dilutive for the years ended December 31, 2014 and 2013.

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

17. Share-Based Compensation Plans

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

	Years Ended December 31,		
	2015	2014	2013
		(Thousands)	
2012 Executive Performance Incentive Program	$ —	$ 7,743	$ 6,739
2013 Executive Performance Incentive Program	6,834	8,208	6,602
2014 Executive Performance Incentive Program	12,865	9,104	—
2015 Executive Performance Incentive Program	12,051	—	—
2011 Volume and Efficiency Program	—	—	13,834
2012 EQT Value Driver Award Program	—	—	2,327
2013 EQT Value Driver Award Program	—	4,403	13,050
2014 EQT Value Driver Award Program	1,116	11,510	—
2014 EQM Value Driver Award Program	622	2,378	—
2015 EQT Value Driver Award Program	14,574	—	—
Restricted stock awards	7,031	4,688	3,033
Non-qualified stock options	1,938	3,002	3,805
Other programs, including non-employee director awards	(2,339)	(409)	9,154
Total share-based compensation expense	$ 54,692	$ 50,627	$ 58,544

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

Cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2015, 2014 and 2013 was $14.0 million, $19.2 million and $32.9 million, respectively. During the years ended December 31, 2015, 2014 and 2013, share-based payment arrangements paid in stock generated tax benefits of $43.1 million, $45.9 million and $14.4 million, respectively.

Executive Performance Incentive Programs

Effective in 2012, the Management Development and Compensation Committee of the Board of Directors (the Compensation Committee) adopted the 2012 Executive Performance Incentive Plan (2012 Incentive PSU Program) under the 2009 Long-Term Incentive Plan. The 2012 Incentive PSU Program was 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 vesting of the units under the 2012 Incentive PSU Program occurred upon payment in the first quarter of 2015, following the expiration of the performance period. Awards granted were earned based on a combination of the level of total shareholder return relative to a predefined peer group and the level of cumulative operating cash flow per share over the period January 1, 2012 through December 31, 2014. The Company accounted for these awards as equity awards using the $123.37 grant date fair value as determined using a Monte Carlo simulation. The Monte Carlo simulation projected the share price, for the Company and its peers, at the ending point of the performance period. The prices were generated using each company's annual volatility for the expected term and the commensurate three-year risk-free rate of 0.36%. Based on the Company's performance relative to the conditions discussed above, 307,323 shares of common stock, valued at $37.9 million based on the Monte Carlo value on the grant date, were distributed during the first quarter of 2015. The total compensation cost capitalized in 2014 and 2013 related to the 2012 Incentive PSU Program was $2.6 million and $8.1 million, respectively.

Effective in 2013, the Compensation Committee adopted the 2013 Executive Performance Incentive Plan (2013 Incentive PSU Program) under the 2009 Long-Term Incentive Plan. The 2013 Incentive PSU Program was 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 vesting of the units under the 2013 Incentive PSU Program will occur upon payment in the first quarter of 2016, following the expiration of the performance period. Awards granted will be earned based on a combination of the level of total shareholder return relative to a predefined peer group and the level of cumulative operating cash flow per share over the period of January 1, 2013 through December 31, 2015. The Company accounted for these awards as equity awards using the $140.00 grant date fair value as determined using a Monte Carlo simulation. The Monte Carlo simulation projected the share price, for the Company and its peers, at the ending point of the performance period. The prices were generated using each company's annual volatility for the expected term and the commensurate three-year risk-free rate of 0.36%. Based on the Company's performance relative to the conditions discussed above, 261,073 shares of common stock, valued at $36.6 million based on the Monte Carlo value on the grant date, are expected to be distributed during the first quarter of 2016. The total compensation cost capitalized in 2015, 2014 and 2013 related to the 2013 Incentive PSU Program was $4.4 million, $5.5 million, and $5.0 million, respectively.

The peer companies for the 2013 Incentive PSU Program are as follows:

Cabot Oil & Gas Corp.	MDU Resources Group, Inc.	Sempra Energy
Chesapeake Energy Corp.	National Fuel Gas Company	SM Energy Company
Cimarex Energy Co.	Newfield Exploration Company	Southwestern Energy Company
Concho Resources, Inc	ONEOK, Inc.	Spectra Energy Corp
CONSOL Energy Inc.	Pioneer Natural Resources Company	Ultra Petroleum Corp.
Energen Corp.	Plains Exploration & Production Co.	Whiting Petroleum Corp.
EOG Resources, Inc.	Questar Corp.	The Williams Companies, Inc.
EXCO Resources, Inc.	Quicksilver Resources Inc.	
MarkWest Energy Partners, L.P.	Range Resources Corp.	

Effective in 2014, the Compensation Committee adopted the 2014 Executive Performance Incentive Plan (2014 Incentive PSU Program) under the 2009 Long-Term Incentive Plan. The 2014 Incentive PSU Program was 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. A total of 259,230 units were outstanding at January 1, 2015. Adjusting for 10,420 forfeitures, there were 248,810 outstanding units as of December 31, 2015. The vesting of the units under the 2014 Incentive PSU Program will occur upon payment after December 31, 2016 (the end of the performance period). The payout factor will vary between zero and 300% of the number of outstanding units contingent upon a combination of the level of total shareholder return relative to a predefined peer group and the level of production sales volume growth over the period January 1, 2014 through December 31, 2016. The Company accounted for these awards as equity awards using the grant date fair value as determined using a Monte Carlo simulation. The Monte Carlo simulation projected the share price, for the Company and its peers, at the ending point of the performance period. The prices were generated using each company's annual volatility for the expected term and the commensurate three-year risk-free rate of 0.78%. As the program includes a performance condition that affects the number of shares that will ultimately vest (the cumulative total sales volume growth performance condition), in accordance with ASC Topic 718, the Monte Carlo simulation computed a grant date fair value for each possible performance condition outcome on the grant date. The Company reevaluates the then-probable outcome at each reporting period, in order to record expense at the probable outcome grant date fair value. As of December 31, 2015, the compensation expense was recorded using a grant date fair value of $189.68 per unit, which was the grant date fair value computed for the outcome which management estimated to be most probable. The total compensation cost capitalized in 2015 and 2014 related to the 2014 Incentive PSU Program was $4.9 million and $4.6 million, respectively. As of December 31, 2015, $15.7 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2014 Incentive PSU Program was expected to be recognized by December 31, 2016.

The peer companies for the 2014 Incentive PSU Program are as follows:

Cabot Oil & Gas Corp.	MarkWest Energy Partners, L.P.	Range Resources Corp.
Chesapeake Energy Corp.	National Fuel Gas Company	SM Energy Company
Cimarex Energy Co.	Newfield Exploration Company	Southwestern Energy Company
Concho Resources, Inc.	Noble Energy, Inc.	Spectra Energy Corp
CONSOL Energy Inc.	ONEOK, Inc.	Ultra Petroleum Corp.
Continental Resources, Inc.	Pioneer Natural Resources Company	Whiting Petroleum Corp.
Energen Corp.	QEP Resources, Inc.	The Williams Companies, Inc.
EOG Resources, Inc.	Questar Corp.	
EXCO Resources, Inc.	Quicksilver Resources, Inc.	

Effective in 2015, the Compensation Committee adopted the 2015 Executive Performance Incentive Plan (2015 Incentive PSU Program) under the 2014 Long-Term Incentive Plan. The 2015 Incentive PSU Program was 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. A total of 369,290 units were granted in 2015 and no additional units may be granted. Adjusting for 12,890 forfeitures, there were 356,400 outstanding units as of December 31, 2015. The vesting of the units under the 2015 Incentive PSU Program will occur upon payment after December 31, 2017 (the end of the performance period). The payout factor will vary between zero and 300% of the number of outstanding units contingent upon a combination of the level of total shareholder return relative to a predefined peer group and the level of production sales volume growth over the period January 1, 2015 through December 31, 2017. The Company accounted for these awards as equity awards using the grant date fair value as determined using a Monte Carlo simulation. The Monte Carlo simulation projected the share price, for the Company and its peers, at the ending point of the performance period. The prices were generated using each company's annual volatility for the expected term and the commensurate three-year risk-free rate of 1.10%. As the program includes a performance condition that affects the number of shares that will ultimately vest (the cumulative total sales volume growth performance condition), in accordance with ASC Topic 718, the Monte Carlo simulation computed a grant date fair value for each possible performance condition outcome on the grant date. The Company reevaluates the then-probable outcome at each reporting period, in order to record expense at the probable outcome grant date fair value. As of December 31, 2015, the compensation expense was recorded using a grant date fair value of $160.13 per unit, which was the grant date fair value computed for the outcome which management estimated to be most probable. The total compensation cost capitalized in 2015 related to the 2015 Incentive PSU Program was $4.9 million. As of December 31, 2015, $33.9 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2015 Incentive PSU Program was expected to be recognized over the next two years.

The peer companies for the 2015 Incentive PSU Program are as follows:

Cabot Oil & Gas Corp.	MarkWest Energy Partners, L.P.	Range Resources Corp.
Chesapeake Energy Corp.	National Fuel Gas Company	SM Energy Company
Cimarex Energy Co.	Newfield Exploration Company	Southwestern Energy Company
Concho Resources, Inc.	Noble Energy, Inc.	Spectra Energy Corp
CONSOL Energy Inc.	ONEOK, Inc.	Ultra Petroleum Corp.
Continental Resources, Inc.	Pioneer Natural Resources Company	Whiting Petroleum Corp.
Energen Corp.	QEP Resources, Inc.	The Williams Companies, Inc.
EOG Resources, Inc.	Questar Corp.	
EXCO Resources, Inc.	Quicksilver Resources, Inc.	

Value Driver Award Programs

Effective in 2012, the Compensation Committee adopted the 2012 Value Driver Award Program (2012 EQT VDPSU) under the 2009 Long-Term Incentive Plan. The 2012 EQT VDPSU was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under the 2012 EQT VDPSU, 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 the payment date following the second anniversary of the grant date. The payments were contingent upon adjusted 2012 EBITDA performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the period January 1, 2012 through December 31, 2012. The two tranches of awards vested and 204,679 awards including accrued dividends were distributed in Company common stock in January 2013 and 194,943 awards including accrued dividends were distributed in February 2014. The Company accounted for these awards as equity awards using the $54.79 grant date fair value per unit which was equal to the Company's common stock price on the date prior to the date of grant. Due to the graded vesting of the award, the Company 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 2012 EQT VDPSU was $2.6 million in 2013.

Effective in 2013, the Compensation Committee adopted the 2013 Value Driver Award Program (2013 EQT VDPSU) under the 2009 Long-Term Incentive Plan. The 2013 EQT VDPSU was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under the 2013 EQT VDPSU, 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 the payment date following the second anniversary of the grant date. The payments were contingent upon adjusted 2013 EBITDA performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the period January 1, 2013 through December 31, 2013. The two tranches of awards vested and 306,076 awards including accrued dividends were distributed in Company common stock in February 2014 and 279,475 awards including accrued dividends were distributed in February 2015. The Company accounts for these awards as equity awards using the $58.98 grant date fair value per unit which was equal to the Company's common stock price on the date prior to the date of grant. Due to the graded vesting of the award, the Company 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 2013 EQT VDPSU was $2.9 million and $14.1 million in 2014 and 2013, respectively.

Effective in 2014, the Compensation Committee adopted the 2014 Value Driver Award Program (2014 EQT VDPSU) under the 2009 Long-Term Incentive Plan. The 2014 EQT VDPSU was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under the 2014 EQT VDPSU, 50% of the units confirmed vested upon payment following the first anniversary of the grant date; the remaining 50% of the units confirmed will vest upon the payment date following the second anniversary of the grant date. The payments were contingent upon adjusted 2014 EBITDA performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the period of January 1, 2014 through December 31, 2014. As of January 1, 2015, 375,426 awards including accrued dividends were outstanding under the 2014 EQT VDPSU. The first tranche of the confirmed awards vested and $14.2 million was paid in cash in February 2015. The remainder of the confirmed awards are expected to vest and be paid in cash in the first quarter of 2016. As of December 31, 2015, 181,928 awards including accrued dividends were outstanding under the 2014 EQT VDPSU. The Company accounts for these awards as liability awards and as such, records compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. Due to the graded vesting of the awards, the Company recognizes 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 EQT VDPSU was $1.3 million and $9.8 million in 2015 and 2014, respectively. The total liability recorded for the 2014 EQT VDPSU was $9.5 million and $21.3 million as of December 31, 2015 and 2014, respectively.

Effective in 2015, the Compensation Committee adopted the 2015 Value Driver Award Program (2015 EQT VDPSU) under the 2014 Long-Term Incentive Plan. The 2015 EQT VDPSU was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under the 2015 EQT VDPSU, 50% of the units confirmed will vest upon payment following the first anniversary of the grant date; the remaining 50% of the units confirmed will vest upon the payment date following the second anniversary of the grant date. The payments are contingent upon adjusted 2015 EBITDA performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the period January 1, 2015 through December 31, 2015. As of December 31, 2015, 448,487 awards including accrued dividends were outstanding under the 2015 EQT VDPSU. The first tranche of the confirmed awards are expected to vest and be distributed in Company common stock in the first quarter 2016. The remainder of the confirmed awards is expected to vest and be paid in Company common stock in the first quarter of 2017. The Company accounts for these awards as equity awards using the $75.70 grant date fair value per unit which was equal to the Company's common stock price on the date prior to the date of grant. Due to the graded vesting of the award, the Company recognizes 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 2015 EQT VDPSU was $10.9 million in 2015. As of December 31, 2015, $8.4 million of unrecognized compensation cost related to the 2015 EQT VDPSU was expected to be fully recognized by December 31, 2016.

2011 Volume and Efficiency Program

Effective in 2011, the Compensation Committee adopted the 2011 Volume and Efficiency Program (2011 VEP) under the 2009 Long-Term Incentive Plan. The 2011 VEP was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. The vesting of the stock units granted under the 2011 VEP occurred upon payment in February 2014 following the expiration of the performance period on December 31, 2013. The vesting resulted in approximately 663,350 awards including accrued dividends being distributed in Company common stock in February 2014. The Company accounted for these awards as equity awards using the $48.06 grant date fair value per unit which was equal to the Company's common stock price on the grant date. The total compensation cost capitalized related to the 2011 VEP was $2.8 million in 2013.

Restricted Stock Awards

The Company granted 158,360, 89,500 and 101,510 restricted stock awards during the years ended December 31, 2015, 2014 and 2013, respectively, to key employees of the Company. The restricted shares granted will be fully vested at the end of the three-year period commencing with the date of grant, assuming continued employment. The weighted average fair value of these restricted stock grants, based on the grant date fair value of the Company's common stock, was approximately $75, $95 and $71 for the years ended December 31, 2015, 2014 and 2013, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2015, 2014 and 2013 was $3.8 million, $1.5 million and $4.3 million, respectively.

As of December 31, 2015, $13.2 million of unrecognized compensation cost related to nonvested restricted stock awards was expected to be recognized over a remaining weighted average vesting term of approximately 1.7 years.

A summary of restricted stock activity as of December 31, 2015, 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, 2015	229,990	$ 74.90	$ 17,225,411
Granted	158,360	$ 75.46	11,949,751
Vested	(71,100)	$ 53.56	(3,808,262)
Forfeited	(17,130)	$ 80.92	(1,386,273)
Outstanding at December 31, 2015	300,120	$ 79.90	$ 23,980,627

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, 2015, 2014 and 2013. 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 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 of options granted represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

	Years Ended December 31,		
	2015	**2014**	**2013**
Risk-free interest rate	1.61%	1.72%	0.76%
Dividend yield	0.12%	0.15%	0.22%
Volatility factor	26.80%	24.80%	31.69%
Expected term	5 years	5 years	5 years

The Company granted 158,200, 133,500 and 259,600 stock options during the years ended December 31, 2015, 2014 and 2013, respectively. The weighted average grant date fair value of the options was $19.90, $22.25 and $16.72 for the years ended December 31, 2015, 2014 and 2013, respectively. The total intrinsic value of options exercised during the years ended December 31, 2015, 2014 and 2013 was $15.1 million, $14.4 million and $22.8 million, respectively.

As of December 31, 2015, $2.9 million of unrecognized compensation cost related to outstanding nonvested stock options was expected to be recognized by December 31, 2017.

A summary of option activity as of December 31, 2015, 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, 2015	1,338,468	$54.08		
Granted	158,200	$75.70		
Exercised	(405,526)	$46.00		
Forfeited	—	—		
Expired	(10,900)	$48.91		
Outstanding at December 31, 2015	1,080,242	$60.33	6.53 years	$2,261,513
Exercisable at December 31, 2015	788,542	$52.25	5.78 years	$2,261,513

Non-employee Directors' Share-Based Awards

The Company has historically granted to non-employee directors share-based awards which vest upon grant of the awards. The value of the share-based awards will be paid in cash or Company common stock upon the directors' termination of service on the Company's Board of Directors. For awards which will be paid in cash, the Company accounts for these awards as liability awards and as such records compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. For awards which will be settled in Company common stock, the Company accounts for these awards as equity awards. A total of 222,251 non-employee director share-based awards including accrued dividends were outstanding as of December 31, 2015. A total of 24,110, 17,900 and 25,500 share-based awards were granted to non-employee directors during the years ended December 31, 2015, 2014 and 2013, respectively. The weighted average fair value of these grants, based on the Company's common stock price on the grant date, was $75.52, $89.78 and $58.98 for the years ended December 31, 2015, 2014 and 2013, respectively.

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 periods 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%. As of January 1, 2015, 139,980 of these performance awards were outstanding. Adjusting for 2,350 forfeitures, there were 137,630 awards outstanding as of December 31, 2015. These awards are expected to vest and be paid in common units of EQM in the first quarter of 2016.

Additionally, 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 14,433 independent director unit-based awards including accrued distributions were outstanding as of December 31, 2015. A total of 2,220, 2,580 and 3,790 unit-based awards were granted to independent directors during the years ended December 31, 2015, 2014 and 2013, respectively. The weighted average fair value of these grants, based on EQM's common unit price on the grant date, was $88.00, $58.79 and $37.92 for the years ended December 31, 2015, 2014 and 2013, respectively.

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) under the 2009 Long-Term Incentive Plan and EQM's 2012 Long-Term Incentive Plan. The 2014 EQM VDPSU 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, 50% of the units confirmed vested upon payment following the first anniversary of the grant date; the remaining 50% of the units confirmed will vest upon the payment date following the second anniversary of the grant date. The performance metrics are EQM's 2014 adjusted EBITDA 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. As of January 1, 2015, 62,845 awards including accrued dividends were outstanding under the 2014 EQM VDPSU. The first tranche of the confirmed awards vested and 31,629 units including accrued dividends were distributed in EQM common units in February 2015. The remainder of the confirmed awards are expected to vest and be paid in EQM common units in the first quarter of 2016. As of December 31, 2015, 28,696 awards including accrued dividends were outstanding under the 2014 EQM VDPSU. EQM accounted for these awards as equity awards using the $58.79 grant date fair value per unit which was equal to EQM's common unit price on the date 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 was less than $0.1 million and $0.3 million in 2015 and 2014, respectively.

EQGP Awards

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 2,928 independent director unit-based awards including accrued distributions were outstanding as of December 31, 2015. The weighted average fair value of these grants, based on EQGP's common unit price on the grant date, was $28.77 for the year ended December 31, 2015.

2016 Value Driver Performance Share Unit Award Program and 2016 Incentive Performance Share Unit Program

Effective in 2016, the Compensation Committee of the Board of Directors adopted the 2016 EQT Value Driver Performance Share Unit Award Program (2016 EQT VDPSU) and the 2016 Incentive Performance Share Unit Program (2016 Incentive PSU Program) under the 2014 Long-Term Incentive Plan. The 2016 EQT VDPSU and 2016 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 377,330 units were granted under the 2016 EQT VDPSU. Fifty percent of the units confirmed under the 2016 EQT VDPSU will vest upon the payment date following the first anniversary of the grant date; the remaining 50% of the confirmed units under the 2016 EQT VDPSU will vest upon the payment date 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 2016 EBITDA performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the period January 1, 2016 through December 31, 2016. If earned, the 2016 EQT VDPSU units are expected to be paid in cash. The Company did not record any obligation or expense related to the 2016 EQT VDPSU as of December 31, 2015.

A total of 468,710 units were granted under the 2016 Incentive PSU Program. The vesting of the units under the 2016 Incentive PSU Program will occur upon payment after December 31, 2018 (the end of the three-year performance period). The payout will vary between zero and 300% of the number of outstanding units contingent upon a combination of the level of total shareholder return relative to a predefined peer group and the level of production sales volume growth over the period January 1, 2016 through December 31, 2018. If earned, the 2016 Incentive PSU Program units are expected to be distributed in Company common stock. The Company did not record any expense related to the 2016 Incentive PSU Program as of December 31, 2015.

2016 Stock Options

Effective January 1, 2016, the Compensation Committee granted 188,600 non-qualified stock options to key employees of the Company. The 2016 options are ten-year options, with an exercise price of $52.13, and are subject to three-year cliff vesting. The Company did not record any expense related to 2016 stock options as of December 31, 2015.

18. Concentrations of Credit Risk

Revenues and related accounts receivable from the EQT Production segment's operations are generated primarily from the sale of produced natural gas, NGLs and crude oil to marketers, utility and industrial customers located mainly in the Appalachian Basin and Northeastern United States and a gas processor in Kentucky and West Virginia. Additionally, a significant amount of revenues and related accounts receivable from EQT Midstream are generated from the gathering of natural gas in Kentucky, Virginia, Pennsylvania and West Virginia. The Company had one customer within the EQT Production segment that accounted for approximately 10%, 12% and 11% of revenues in 2015, 2014 and 2013, respectively.

Approximately 79% and 87% of the Company's accounts receivable balance as of December 31, 2015 and 2014, 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, 2015, 2014 or 2013.

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 believes that NYMEX-traded future contracts have limited credit risk because Commodity Futures Trading Commission (CFTC) regulations are in place to protect exchange participants, including the Company, from any potential financial instability of the exchange members. The Company's OTC swap and collar 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 with financial counterparties that are of investment grade or better, enters into netting agreements whenever possible and may obtain collateral or other security.

As of December 31, 2015, 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.

19. 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, 2015 totaled $11.7 billion (2016 - $314.2 million, 2017 - $392.7 million, 2018 - $447.6 million, 2019 - $741.2 million, 2020 - $736.1 million and thereafter - $9,040.2 million). 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 $5.7 billion as of December 31, 2015.

If Moody's or another 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, the Company 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, and the potential pool of investors and funding sources may decrease.

The Company has agreements with drilling contractors to provide drilling equipment and services to the Company. These obligations totaled approximately $63.2 million as of December 31, 2015. Operating lease rentals for drilling contractors, office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately $85.2 million in 2015, $65.6 million in 2014 and $56.0 million in 2013. Future lease payments under non-cancelable operating leases as of December 31, 2015 totaled $155.5 million (2016 - $41.5 million, 2017 - $31.5 million, 2018 - $19.7 million, 2019 – $11.9 million, 2020 - $9.8 million and thereafter - $41.1 million).

During 2014, EQM announced that it will construct and own the Ohio Valley Connector (OVC) pipeline. The OVC includes a 37-mile pipeline that will extend EQM’s transmission and storage system from northern West Virginia to Clarington, Ohio, at which point it will interconnect with the Rockies Express Pipeline and may interconnect with other pipelines and liquidity points. The Company has entered into a 20 years precedent agreement for a total of 650 BBtu per day of firm transmission capacity on the OVC. EQM received its FERC certificate to construct and operate the OVC on December 30, 2015 and construction began in January 2016. EQM expects the OVC to be in-service by year-end 2016.

During 2015, the Company assigned its interest in the MVP Joint Venture to EQM. The MVP Joint Venture plans to construct the MVP, an estimated 300-mile natural gas interstate pipeline spanning from northern West Virginia to southern Virginia. The MVP Joint Venture has secured a total of 2.0 Bcf per day of 20-year firm capacity commitments, including a 1.29 Bcf per day firm capacity commitment by the Company. The MVP Joint Venture submitted the MVP certificate application to the FERC in October 2015 and anticipates receiving the certificate in the fourth quarter of 2016. Subject to FERC approval, construction is scheduled to begin shortly thereafter and the pipeline is expected to be in-service during the fourth quarter of 2018.

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 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 $1.0 million is included in other liabilities and credits in the Consolidated Balance Sheets as of December 31, 2015.

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.

20. 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 $134 million as of December 31, 2015, extending at a decreasing amount for approximately 12 years.

In December 2014, the Company issued a performance guarantee (the EQT MVP Guarantee) in connection with the obligations of MVP Holdco to fund its proportionate share of the construction budget for the MVP. Upon the transfer of the MVP Interest to EQM on March 30, 2015, EQM entered into a performance guarantee (the Initial EQM Guarantee) on terms and conditions similar to the EQT MVP Guarantee, and the EQT MVP Guarantee was concurrently terminated. Upon the FERC's initial release to begin construction of the MVP, the Initial EQM Guarantee will terminate, and EQM will be obligated to issue a new guarantee in an amount equal to 33% of MVP Holdco's remaining obligations to make capital contributions to the MVP Joint Venture in connection with the then remaining construction budget, less any credit assurances issued by any affiliate of EQM under such affiliate's precedent agreement with the MVP Joint Venture. As of December 31, 2015, the Initial EQM Guarantee was in the amount of $108 million. As a result of the ConEd Transaction, the amount of the Initial EQM Guarantee decreased to $91 million as of February 11, 2016.

21. Interim Financial Information (Unaudited)

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

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(Thousands, except per share amounts)			
2015 (a)				
Total operating revenues (b)	$ 714,815	$ 439,589	$ 583,978	$ 601,380
Operating income	314,759	33,034	170,055	45,291
Net income (loss) attributable to EQT Corporation	173,427	5,536	40,787	(134,579)
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
Net income (loss)	$ 1.14	$ 0.04	$ 0.27	$ (0.88)
Diluted:				
Net income (loss)	$ 1.14	$ 0.04	$ 0.27	$ (0.88)
2014 (a)				
Total operating revenues	$ 661,625	$ 526,168	$ 578,723	$ 703,194
Operating income	356,791	224,771	231,503	40,330
Amounts attributable to EQT Corporation:				
Income (loss) from continuing operations	192,297	109,045	98,555	(14,303)
(Loss) income from discontinued operations	(104)	1,876	—	(401)
Net income (loss) attributable to EQT Corporation	$ 192,193	$ 110,921	$ 98,555	$ (14,704)
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
Income (loss) from continuing operations	$ 1.27	$ 0.72	$ 0.65	$ (0.10)
Income from discontinued operations	—	0.01	—	—
Net income (loss)	$ 1.27	$ 0.73	$ 0.65	$ (0.10)
Diluted:				
Income (loss) from continuing operations	$ 1.26	$ 0.72	$ 0.65	$ (0.10)
Income from discontinued operations	—	0.01	—	—
Net income (loss)	$ 1.26	$ 0.73	$ 0.65	$ (0.10)

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

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

22. 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, NGL and oil production activities (a):

	For the Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
At December 31:			
Capitalized Costs:			
Proved properties	$ 10,918,499	$ 9,258,298	$ 7,702,724
Unproved properties	898,270	824,527	450,227
Total capitalized costs	11,816,769	10,082,825	8,152,951
Accumulated depreciation and depletion	3,425,618	2,693,535	2,134,953
Net capitalized costs	$ 8,391,151	$ 7,389,290	$ 6,017,998

	For the Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Costs incurred:			
Property acquisition:			
Proved properties (b)	$ 23,890	$ 231,322	$ 90,390
Unproved properties (c)	158,405	493,067	95,861
Exploration (d)	53,463	16,023	4,285
Development	1,633,498	1,697,501	1,230,301

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

(b) Amounts include $198.2 million and $1.1 million for the purchase of Permian wells and leases, respectively, acquired in the Range transaction in 2014 and $57.0 million and $15.3 million for the purchase of Marcellus wells and leases, respectively, acquired in the Chesapeake transaction in 2013.

(c) Amounts include $317.2 million for the purchase of Permian leases acquired in the Range transaction in 2014. Amounts include $41.9 million for the purchase of Marcellus leases acquired in the Chesapeake transaction in 2013.

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

Capitalized costs of unproved oil and gas properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes in development plans resulting from economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves prior to the expiration or abandonment of the lease, the related costs are expensed in the period in which that determination is made. For the years ended December 31, 2015 and 2014, the Company recorded unproved property impairments of $19.7 million and $86.6 million, respectively, which are included in the impairment of long-lived assets in the Statements of Consolidated Income. In addition, unproved oil and gas property impairments primarily as a result of lease expirations prior to drilling of $37.4 million, $14.6 million and $14.2 million are included in exploration expense for the years ended December 31, 2015, 2014 and 2013, respectively. Unproved properties had a net book value of $898.3 million and $824.5 million at December 31, 2015 and 2014, respectively.

Results of Operations for Producing Activities

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

	For the Years Ended December 31,		
	2015	2014	2013
	(Thousands)		
Revenues:			
Affiliated	$ 1,412	$ 4,761	$ 5,912
Nonaffiliated	1,154,422	1,724,771	1,305,026
Production costs	398,044	334,050	250,372
Exploration costs	61,970	21,665	18,483
Depreciation, depletion and accretion	723,448	592,855	578,641
Impairment of long-lived assets	118,268	267,339	—
Income tax (benefit) expense	(58,603)	202,881	183,060
Results of operations from producing activities (excluding corporate overhead)	$ (87,293)	$ 310,742	$ 280,382

Reserve Information

The information presented below represents estimates of proved natural gas, NGL and oil reserves prepared by Company engineers. The engineer primarily responsible for preparing the reserve report and the technical aspects of the reserves audit received a bachelor's degree in Chemical Engineering from the Pennsylvania State University and has 18 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, NGL 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, NGL and oil proved reserves attributable to the Company's interests as of December 31, 2015. Ryder Scott conducted a detailed, well by well, audit of the Company's largest properties. This audit covered 80% of the Company's proved developed reserves. Ryder Scott's audit of the remaining 20% of the Company's proved developed properties consisted of an audit of aggregated groups not exceeding 200 wells per case for operated wells and 230 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,		
	2015	2014	2013
	(Millions of Cubic Feet)		
Total - Natural Gas, Oil, and NGLs (a)			
Proved developed and undeveloped reserves:			
Beginning of year	10,738,948	8,348,269	6,004,952
Revision of previous estimates	(2,194,675)	(301,351)	191,509
Purchase of hydrocarbons in place	—	102,713	472,798
Sale of hydrocarbons in place	(61)	(198,657)	(455)
Extensions, discoveries and other additions	2,051,071	3,276,054	2,046,578
Production	(618,686)	(488,080)	(367,113)
End of year	9,976,597	10,738,948	8,348,269
Proved developed reserves:			
Beginning of year	4,826,387	3,985,687	2,798,381
End of year	6,279,557	4,826,387	3,985,687
Proved undeveloped reserves:			
Beginning of year	5,912,561	4,362,582	3,206,571
End of year	3,697,040	5,912,561	4,362,582

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

	Years Ended December 31,		
	2015	2014	2013
	(Millions of Cubic Feet)		
Natural Gas			
Proved developed and undeveloped reserves:			
Beginning of year	9,775,954	7,561,561	5,985,758
Revision of previous estimates	(2,059,531)	(228,085)	(375,887)
Purchase of natural gas in place	—	44,867	472,798
Sale of natural gas in place	(61)	(198,531)	(455)
Extensions, discoveries and other additions	1,955,935	3,040,938	1,844,840
Production	(561,986)	(444,796)	(365,493)
End of year	9,110,311	9,775,954	7,561,561
Proved developed reserves:			
Beginning of year	4,257,377	3,567,313	2,779,187
End of year	5,652,989	4,257,377	3,567,313
Proved undeveloped reserves:			
Beginning of year	5,518,577	3,994,248	3,206,571
End of year	3,457,322	5,518,577	3,994,248

	Years Ended December 31,		
	2015	2014	2013
	(Thousands of Bbls)		
Oil (a)			
Proved developed and undeveloped reserves:			
Beginning of year	5,005	3,956	3,199
Revision of previous estimates	1,219	(905)	270
Purchase of oil in place	—	2,165	—
Sale of oil in place	—	(3)	—
Extensions, discoveries and other additions	419	241	757
Production	(743)	(449)	(270)
End of year	5,900	5,005	3,956
Proved developed reserves:			
Beginning of year	5,005	3,892	3,199
End of year	5,900	5,005	3,892
Proved undeveloped reserves:			
Beginning of year	—	64	—
End of year	—	—	64

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

	Years Ended December 31,		
	2015	2014	2013
	(Thousands of Bbls)		
NGLs (a)			
Proved developed and undeveloped reserves:			
Beginning of year	155,494	127,162	—
Revision of previous estimates	(23,743)	(11,306)	94,296
Purchase of NGLs in place	—	7,476	—
Sale of NGLs in place	—	(18)	—
Extensions, discoveries and other additions	15,437	38,945	32,866
Production	(8,707)	(6,765)	—
End of year	138,481	155,494	127,162
Proved developed reserves:			
Beginning of year	89,830	65,837	—
End of year	98,528	89,830	65,837
Proved undeveloped reserves:			
Beginning of year	65,664	61,325	—
End of year	39,953	65,664	61,325

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

During 2015, the Company recorded net downward revisions of 2,195 Bcfe to the December 31, 2014 estimates of its reserves due primarily to the removal of 2,168 Bcfe associated with undeveloped locations that are not currently planned to be drilled within 5 years of initial booking. The majority of these locations are no longer economic as determined in accordance with SEC pricing requirements, while 342 Bcfe of proved undeveloped reserves were removed for economic locations that the Company no longer intends to develop within 5 years of booking. Additional downward revisions of 259 Bcfe were associated with previously booked locations whose economic lives have been shortened due to reduced commodity prices. These decreases were partially offset by 386 Bcfe of increased proved developed reserves primarily due to improved performance of producing locations. The Company's 2015 extensions, discoveries and other additions, resulting from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery, of 2,051 Bcfe exceeded the 2015 production of 619 Bcfe. These reserve extensions and discoveries were mainly due to the addition of proved undeveloped locations in the Company's Pennsylvania and West Virginia Marcellus fields, the extension of lateral lengths associated with existing proved undeveloped locations, and the development of locations not previously booked as proved.

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

During 2014, the Company recorded net downward revisions of 301.4 Bcfe to the December 31, 2013 estimates of its reserves due primarily to the removal of 1,047.2 Bcfe associated with undeveloped locations that would not be drilled within 5 years of initial booking. This total included locations that were no longer economic in accordance with SEC pricing requirements as well as the remainder of proved undeveloped Huron locations that were no longer planned for development following the Company’s decision to suspend development of this play. This decrease was partially offset by 845.1 Bcfe of increased reserves primarily due to improved performance of proved developed producing locations and increased lateral lengths for previously booked undeveloped Marcellus locations. The Company’s 2014 extensions, discoveries and other additions, resulting from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery, of 3,276.1 Bcfe exceeded the 2014 production of 488.1 Bcfe. These reserve extensions and discoveries were mainly due to the addition of proved undeveloped locations in the Company’s Pennsylvania and West Virginia Marcellus fields and the development of locations not previously booked as proved.

During 2013, the Company recorded upward revisions of 191.5 Bcfe to the December 31, 2012 estimates of its reserves primarily due to the increase in the average NYMEX natural gas price for the year causing the properties to remain economic for a longer period. This increase was partially offset by negative revisions of 349 Bcfe, which was primarily due to the removal of 58 undeveloped locations and their associated reserves. The Company included NGL reserves for the first time in 2013. This caused a one-time decrease in gas reserves and an increase in equivalent NGL reserves. The Company’s 2013 extensions, discoveries and other additions, resulting from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery, of 2,046.6 Bcfe exceeded the 2013 production of 367.1 Bcfe. These reserve extensions and discoveries were mainly due to decreased lateral spacing in one of the Company’s locations in Greene County, Pennsylvania, and additional proved locations in the Company’s Pennsylvania and West Virginia Marcellus fields and the addition of Huron proved undeveloped reserves due to the re-establishment of the Huron development program.

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%.

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

	2015	2014	2013
		(Thousands)	
Future cash inflows (a)	$ 10,071,465	$ 30,428,815	$ 25,912,542
Future production costs	(3,415,715)	(4,868,079)	(4,180,136)
Future development costs	(2,377,650)	(5,052,195)	(4,199,722)
Future income tax expenses	(1,333,989)	(7,718,407)	(6,533,817)
Future net cash flow	2,944,111	12,790,134	10,998,867
10% annual discount for estimated timing of cash flows	(1,966,557)	(7,980,106)	(7,047,588)
Standardized measure of discounted future net cash flows	$ 977,554	$ 4,810,028	$ 3,951,279

(a) 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 West Texas Intermediate (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, NGL pricing using arithmetic averages of the closing prices on the first day of each month during 2015 for NGL components and adjusted using the regional component makeup of produced NGLs resulted in prices of $17.60 per Bbl of NGLs from West Virginia Marcellus reserves in Doddridge, Ritchie, and Wetzel counties, $21.69 per Bbl of NGLs from certain Kentucky reserves, $16.84 per Bbl for Utica reserves, and $17.51 per Bbl for Permian reserves.

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

For 2013, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2013 of $89.22 per Bbl of oil (first day of each month closing price for WTI less regional adjustments), $3.653 per Dth for Columbia Gas Transmission Corp., $3.447 per Dth for Dominion Transmission, Inc., $3.693 per Dth for the East Tennessee Natural Gas Pipeline, $3.495 per Dth for Texas Eastern Transmission Corp., $2.842 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company and $3.521 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company. For 2013, NGL pricing using arithmetic averages of the closing prices on the first day of each month during 2013 for NGL components and adjusted using the regional component makeup of produced NGLs resulted in prices of $51.91 per Bbl of NGLs from West Virginia Marcellus reserves in Doddridge, Ritchie, and Wetzel counties, $49.38 per Bbl of NGLs from certain Kentucky reserves, and $48.14 per Bbl for Utica 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, 2015 discounted future net cash flows before income taxes of the Company's proved reserves of approximately $788.6 million, $26.0 million and $533.8 million, respectively.

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

	2015	2014	2013
		(Thousands)	
Sales and transfers of natural gas and oil produced – net	$ (757,789)	$ (1,479,242)	$ (1,060,566)
Net changes in prices, production and development costs	(5,566,232)	(1,525,944)	(292,533)
Extensions, discoveries and improved recovery, less related costs	264,735	2,300,923	1,509,002
Development costs incurred	971,186	1,023,075	1,319,135
Purchase of minerals in place – net	—	72,139	348,608
Sale of minerals in place – net	(43)	(146,476)	(252)
Revisions of previous quantity estimates	(1,541,419)	(222,195)	106,170
Accretion of discount	600,099	578,676	343,502
Net change in income taxes	2,424,200	(529,337)	(1,031,105)
Timing and other	(227,211)	787,130	554,159
Net (decrease) increase	(3,832,474)	858,749	1,796,120
Beginning of year	4,810,028	3,951,279	2,155,159
End of year	$ 977,554	$ 4,810,028	$ 3,951,279

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

Not Applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2015 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

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

EQT's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2015. 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, 2015.

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

Item 9B. Other Information

Not Applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following information is incorporated herein by reference from the Company’s definitive proxy statement relating to the annual meeting of shareholders to be held on April 20, 2016, which proxy statement will be filed with the SEC within 120 days after the close of the Company’s fiscal year ended December 31, 2015:

- 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(c)(3) of Regulation S-K with respect to changes to the procedures by which security holders may recommend nominees to the Company's Board of Directors is incorporated herein by reference from the section captioned "Corporate Governance and Board Matters - Director Nominations" 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 11, 2016),” and is incorporated herein by reference.

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

Item 11. Executive Compensation

The following information is incorporated herein by reference from the Company’s definitive proxy statement relating to the annual meeting of shareholders to be held on April 20, 2016, which proxy statement will be filed with the SEC within 120 days after the close of the Company’s fiscal year ended December 31, 2015:

- 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 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.

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

Information required by Item 403 of Regulation S-K with respect to stock ownership of significant shareholders, directors and executive officers is incorporated herein by reference to the sections captioned "Equity Ownership - Stock Ownership of Significant Shareholders" and "Equity Ownership - Equity Ownership of Directors and Executive Officers" in the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 20, 2016, which will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2015.

Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2015 with respect to shares of the Company's common stock that may be issued under the Company's existing equity compensation plans, including the 2014 Long-Term Incentive Plan (2014 LTIP), the 2009 Long-Term Incentive Plan (2009 LTIP), the 1999 Non-Employee Directors' Stock Incentive Plan (1999 NEDSIP), the 2005 Directors' Deferred Compensation Plan (2005 DDCP), the 1999 Directors' Deferred Compensation Plan (1999 DDCP) and the 2008 Employee Stock Purchase Plan (2008 ESPP):

Plan Category	Number Of Securities To Be Issued Upon Exercise Of Outstanding Options, Warrants and Rights (A)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (B)	Number Of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected In Column A) (C)
Equity Compensation Plans Approved by Shareholders [1]	4,560,867 [2]	$ 60.33 [3]	5,370,811 [4]
Equity Compensation Plans Not Approved by Shareholders [5]	26,547 [6]	N/A	170,887
Total	4,587,414	$ 60.33	5,541,698

(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 Long-Term Incentive Plan (1999 LTIP) and the 1999 NEDSIP. All outstanding awards under the 1999 LTIP expired in August of 2015. 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) 158,200 shares subject to outstanding stock options under the 2014 LTIP; (ii) 1,867,923 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 622,641 *target* awards and dividend reinvestments thereon)); (iii) 24,149 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon; (iv) 922,042 shares subject to outstanding stock options under the 2009 LTIP; (v) 1,535,215 shares subject to outstanding performance awards under the 2009 LTIP, inclusive of dividend reinvestments thereon (counted at a 3X multiple assuming maximum performance is achieved under the awards (representing 511,738 *target* awards and dividend reinvestments thereon)); (vi) 43,563 shares subject to outstanding directors' deferred stock units under the 2009 LTIP, inclusive of dividend reinvestments thereon; and (vii) 9,775 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 6.53 years as of December 31, 2015.

(4) Consists of (i) 5,629,396 shares available for future issuance under the 2014 LTIP, (ii) a "notional" deficit of (928,533) shares under the 2009 LTIP and (iii) 669,948 shares available for future issuance under the 2008 ESPP. As of December 31, 2015, 7,887 shares were subject to purchase under the 2008 ESPP.

The "notional" deficit under the 2009 LTIP results from counting outstanding performance awards under the 2009 LTIP at a 3X multiple assuming maximum performance is achieved under the awards. The actual number of shares the Management Development and Compensation Committee will award at the end of the applicable performance periods will range between 0% and 300% of the target awards, based upon, among other things, the Company's achievement of stated performance measures under the awards, as certified by the Management Development and Compensation Committee. However, to the extent insufficient shares remain available for future issuance under the 2009 LTIP upon the applicable payout dates of such performance awards, the awards will be settled (i) with shares reserved for issuance under the 2014 LTIP or (ii) in cash.

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

(6) Reflects the number of shares invested in the EQT Common Stock Fund, payable in shares of common stock, allocated to non-employee directors' accounts under the 2005 DDCP and the 1999 DDCP as of December 31, 2015.

2005 Directors' Deferred Compensation Plan

The 2005 DDCP was adopted by the Management Development and Compensation Committee, effective January 1, 2005. The plan has been amended to, among other things, allow the plan to continue into 2006 and thereafter and to comply with the documentation requirements of Internal Revenue Code Section 409A. 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 upon retirement from the Board, but may be payable earlier if an early payment is authorized after a director suffers an unforeseeable financial emergency. In addition to deferred directors' fees and retainers and a one-time grant of deferred shares in 1999 resulting from the curtailment of the directors' retirement plan, the deferred stock units granted to directors and vested prior to January 1, 2005 under the 1999 NEDSIP are administered under this plan.

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

Information required by Items 404 and 407(a) of Regulation S-K with respect to director independence and related person transactions is incorporated herein by reference to the section captioned "Corporate Governance and Board Matters – Independence and Related Person Transactions" in the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 20, 2016, which proxy statement will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2015.

Item 14. Principal Accounting Fees and Services

Information required by Item 9(e) of Schedule 14A is incorporated herein by reference to the section captioned "Item No. 4 – Ratification of Appointment of Independent Registered Public Accounting Firm" in the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 20, 2016, which proxy statement will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2015.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1 Financial Statements

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

2 Financial Statement Schedule

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

3 Exhibits

The exhibits listed on the accompanying index to exhibits (pages 121 through 127) are filed (or, as applicable, furnished) as part of this Annual Report on Form 10-K.

EQT CORPORATION

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

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

2. Schedule for the Three Years Ended December 31, 2015 included in Part IV:

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

EQT CORPORATION AND SUBSIDIARIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2015

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:					
2015	$ 64,987	$ 91,097	$ —	$ —	$ 156,084
2014	$ 56,404	$ 9,314	$ —	$ (731)	$ 64,987
2013	$ 66,236	$ (9,832)	$ —	$ —	$ 56,404

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
2.01(a)	Master Purchase Agreement dated as of December 19, 2012 among the Company, Distribution Holdco, LLC and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.1 to Form 8-K filed on December 20, 2012
2.01(b)	Amendment No. 1 to Master Purchase Agreement dated as of February 22, 2013 among the Company, Distribution Holdco, LLC and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.01 to Form 10-Q for the quarter ended March 31, 2013
2.01(c)	Amendment No. 2 to Master Purchase Agreement dated as of December 17, 2013 among the Company, Distribution Holdco, LLC and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.1 to Form 8-K filed on December 19, 2013
2.02(a)	Asset Exchange Agreement dated as of December 19, 2012 between the Company and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.2 to Form 8-K filed on December 20, 2012
2.02(b)	Amendment to Asset Exchange Agreement dated as of December 17, 2013 between the Company and PNG Companies LLC	Incorporated herein by reference to Exhibit 2.2 to Form 8-K filed on December 19, 2013
3.01	Restated Articles of Incorporation of EQT Corporation (amended through April 17, 2013)	Incorporated herein by reference to Exhibit 3.01 to Form 10-Q for the quarter ended March 31, 2013
3.02	Amended and Restated Bylaws of EQT Corporation (amended through October 14, 2015)	Incorporated herein by reference to Exhibit 3.1 to Form 8-K filed on October 15, 2015
4.01(a)	Indenture dated as of April 1, 1983 between the Company and Pittsburgh National Bank, as Trustee	Incorporated herein by reference to Exhibit 4.01(a) to Form 10-K for the year ended December 31, 2007
4.01(b)	Instrument appointing Bankers Trust Company as successor trustee to Pittsburgh National Bank	Incorporated herein by reference to Exhibit 4.01(b) to Form 10-K for the year ended December 31, 1998
4.01(c)	1991 Supplemental Indenture dated as of March 15, 1991 between the Company and Bankers Trust Company, as Trustee, eliminating limitations on liens and additional funded debt	Incorporated herein by reference to Exhibit 4.01(f) to Form 10-K for the year ended December 31, 1996
4.01(d)	Resolution adopted August 19, 1991 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 27, establishing the terms and provisions of the Series A Medium-Term Notes	Incorporated herein by reference to Exhibit 4.01(g) to Form 10-K for the year ended December 31, 1996
4.01(e)	Resolutions adopted July 6, 1992 and February 19, 1993 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 8, establishing the terms and provisions of the Series B Medium-Term Notes	Incorporated herein by reference to Exhibit 4.01(h) to Form 10-K for the year ended December 31, 1997
4.01(f)	Resolution adopted July 14, 1994 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 and 2, establishing the terms and provisions of the Series C Medium-Term Notes	Incorporated herein by reference to Exhibit 4.01(i) to Form 10-K for the year ended December 31, 1995
4.01(g)	Second Supplemental Indenture dated as of June 30, 2008 between the Company and Deutsche Bank Trust Company Americas, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Incorporated herein by reference to Exhibit 4.01(g) to Form 8-K filed on July 1, 2008

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
4.02(a)	Indenture dated as of July 1, 1996 between the Company and The Bank of New York, as successor to Bank of Montreal Trust Company, as Trustee	Incorporated herein by reference to Exhibit 4.01(a) to Form S-4 Registration Statement (#333-103178) filed on February 13, 2003
4.02(b)	Resolutions adopted January 18 and July 18, 1996 by the Board of Directors of the Company and Resolution adopted July 18, 1996 by the Executive Committee of the Board of Directors of the Company, establishing the terms and provisions of the 7.75% Debentures issued July 29, 1996	Incorporated herein by reference to Exhibit 4.01(j) to Form 10-K for the year ended December 31, 1996
4.02(c)	Officer's Declaration dated as of February 20, 2003 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of up to $200,000,000	Incorporated herein by reference to Exhibit 4.01(c) to Form S-4 Registration Statement (#333-104392) filed on April 8, 2003
4.02(d)	Officer's Declaration dated as of November 7, 2002 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of up to $200,000,000	Incorporated herein by reference to Exhibit 4.01(c) to Form S-4/A Registration Statement (#333-103178) filed on March 12, 2003
4.02(e)	Officer's Declaration dated as of September 27, 2005 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of $150,000,000	Incorporated herein by reference to Exhibit 4.01(b) to Form S-4 Registration Statement (#333-104392) filed on October 28, 2005
4.02(f)	Supplemental Indenture dated as of June 30, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Incorporated herein by reference to Exhibit 4.02(f) to Form 8-K filed on July 1, 2008
4.03(a)	Indenture dated as of March 18, 2008 between the Company and The Bank of New York, as Trustee	Incorporated herein by reference to Exhibit 4.1 to Form 8-K filed on March 18, 2008
4.03(b)	First Supplemental Indenture (including the form of senior note) dated as of March 18, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which the 6.5% Senior Notes due 2018 were issued	Incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on March 18, 2008
4.03(c)	Second Supplemental Indenture dated as of June 30, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Incorporated herein by reference to Exhibit 4.03(c) to Form 8-K filed on July 1, 2008
4.03(d)	Third Supplemental Indenture dated as of May 15, 2009 between the Company and The Bank of New York, as Trustee, pursuant to which the 8.13% Senior Notes due 2019 were issued	Incorporated herein by reference to Exhibit 4.1 to Form 8-K filed on May 15, 2009
4.03(e)	Fourth Supplemental Indenture dated as of November 7, 2011 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 4.88% Senior Notes due 2021 were issued	Incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on November 7, 2011
4.04(a)	Indenture dated as of August 1, 2014 among EQT Midstream Partners, LP, the subsidiary guarantors party thereto, and The Bank of New York Mellon Trust Company, N.A., as Trustee	Incorporated herein by reference to Exhibit 4.01 to Form 10-Q for the quarter ended September 30, 2014

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
4.04(b)	First Supplemental Indenture dated as of August 1, 2014 among EQT Midstream Partners, LP, the subsidiary guarantors party thereto, and The Bank of New York Mellon Trust Company, N.A., as Trustee, pursuant to which the EQT Midstream Partners, LP 4.00% Senior Notes due 2024 were issued	Incorporated herein by reference to Exhibit 4.02 to Form 10-Q for the quarter ended September 30, 2014
* 10.01(a)	2009 Long-Term Incentive Plan (as amended and restated July 11, 2012)	Incorporated herein by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2012
* 10.01(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (pre-2013 grants)	Incorporated herein by reference to Exhibit 10.02(b) to Form 10-K for the year ended December 31, 2012
* 10.01(c)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (pre-2012 grants)	Incorporated herein by reference to Exhibit 10.01(q) to Form 10-K for the year ended December 31, 2010
* 10.01(d)	Form of Amendment to Stock Option Award Agreements	Incorporated herein by reference to Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2011
* 10.01(e)	2011 Volume and Efficiency Program	Incorporated herein by reference to Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2011
* 10.01(f)	Form of Participant Award Agreement under 2011 Volume and Efficiency Program	Incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2011
* 10.01(g)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2012 grants)	Incorporated herein by reference to Exhibit 10.02(n) to Form 10-K for the year ended December 31, 2011
* 10.01(h)	2012 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(q) to Form 10-K for the year ended December 31, 2011
* 10.01(i)	Form of Participant Award Agreement under 2012 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(r) to Form 10-K for the year ended December 31, 2011
* 10.01(j)	Form of EQM TSR Performance Award Agreement under 2009 Long-Term Incentive Plan and EQT Midstream Services, LLC 2012 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.02(r) to Form 10-K for the year ended December 31, 2012
* 10.01(k)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (2013 and 2014 grants)	Incorporated herein by reference to Exhibit 10.02(s) to Form 10-K for the year ended December 31, 2012
* 10.01(l)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2013 grants)	Incorporated herein by reference to Exhibit 10.02(t) to Form 10-K for the year ended December 31, 2012
* 10.01(m)	2013 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(u) to Form 10-K for the year ended December 31, 2012
* 10.01(n)	Form of Participant Award Agreement under 2013 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(v) to Form 10-K for the year ended December 31, 2012

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.01(o)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2014 grants)	Incorporated herein by reference to Exhibit 10.02(v) to Form 10-K for the year ended December 31, 2013
* 10.01(p)	2014 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(w) to Form 10-K for the year ended December 31, 2013
* 10.01(q)	Form of Participant Award Agreement under 2014 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.02(x) to Form 10-K for the year ended December 31, 2013
* 10.02(a)	2014 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on May 1, 2014
* 10.02(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2014 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.03(b) to Form 10-K for the year ended December 31, 2014
* 10.02(c)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.03(c) to Form 10-K for the year ended December 31, 2014
* 10.02(d)	2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(d) to Form 10-K for the year ended December 31, 2014
* 10.02(e)	Form of Participant Award Agreement under 2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(e) to Form 10-K for the year ended December 31, 2014
* 10.02(f)	Amendment to 2015 Executive Performance Incentive Program	Incorporated herein by reference to Exhibit 10.03(f) to Form 10-K for the year ended December 31, 2014
* 10.02(g)	2016 Incentive Performance Share Unit Program	Filed herewith as Exhibit 10.02(g)
* 10.02(h)	Form of Participant Award Agreement under 2016 Incentive Performance Share Unit Program	Filed herewith as Exhibit 10.02(h)
* 10.03(a)	EQT GP Services, LLC 2015 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.3 to EQT GP Holdings, LP's Form 8-K filed on May 15, 2015
* 10.03(b)	Form of EQT GP Holdings, LP Phantom Unit Award Agreement	Incorporated herein by reference to Exhibit 10.5 to Amendment No. 1 to EQT GP Holdings, LP's Form S-1 Registration Statement (#333-202053) filed on April 1, 2015
* 10.04	EQT Midstream Services, LLC 2012 Long-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.03 to Form 10-K for the year ended December 31, 2012
* 10.05(a)	1999 Non-Employee Directors’ Stock Incentive Plan (as amended and restated December 3, 2008)	Incorporated herein by reference to Exhibit 10.02(a) to Form 10-K for the year ended December 31, 2008
* 10.05(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 1999 Non-Employee Directors’ Stock Incentive Plan	Incorporated herein by reference to Exhibit 10.04(c) to Form 10-K for the year ended December 31, 2006

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.06	2011 Executive Short-Term Incentive Plan	Incorporated herein by reference to Exhibit 10.2 to Form 8-K filed on May 10, 2011
* 10.07	2006 Payroll Deduction and Contribution Program (as amended and restated July 7, 2015)	Incorporated herein by reference to Exhibit 10.06 to Form 10-Q for the quarter ended June 30, 2015
* 10.08	1999 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014)	Incorporated herein by reference to Exhibit 10.08 to Form 10-K for the year ended December 31, 2014
* 10.09	2005 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014)	Incorporated herein by reference to Exhibit 10.09 to Form 10-K for the year ended December 31, 2014
* 10.10(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and David L. Porges	Incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on July 31, 2015
* 10.10(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and David L. Porges	Incorporated herein by reference to Exhibit 10.10(b) to Form 10-K for the year ended December 31, 2012
* 10.10(c)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and David L. Porges	Incorporated herein by reference to Exhibit 10.6 to Form 8-K filed on July 31, 2015
* 10.11(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.2 to Form 8-K filed on July 31, 2015
* 10.11(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.11(b) to Form 10-K for the year ended December 31, 2012
* 10.11(c)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.7 to Form 8-K filed on July 31, 2015
* 10.12(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.3 to Form 8-K filed on July 31, 2015
* 10.12(b)	Amendment to Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement effective as of January 1, 2016 between the Company and Randall L. Crawford	Filed herewith as Exhibit 10.12(b)
* 10.12(c)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.12(b) to Form 10-K for the year ended December 31, 2012
* 10.12(d)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.8 to Form 8-K filed on July 31, 2015
* 10.13(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and Lewis B. Gardner	Incorporated herein by reference to Exhibit 10.4 to Form 8-K filed on July 31, 2015
* 10.13(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Lewis B. Gardner	Incorporated herein by reference to Exhibit 10.13(b) to Form 10-K for the year ended December 31, 2012

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.13(c)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and Lewis B. Gardner	Incorporated herein by reference to Exhibit 10.9 to Form 8-K filed on July 31, 2015
* 10.14(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of July 29, 2015 between the Company and Steven T. Schlotterbeck	Incorporated herein by reference to Exhibit 10.5 to Form 8-K filed on July 31, 2015
* 10.14(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Steven T. Schlotterbeck	Incorporated herein by reference to Exhibit 10.14(b) to Form 10-K for the year ended December 31, 2012
* 10.14(c)	Termination of Amended and Restated Change of Control Agreement dated as of July 29, 2015 between the Company and Steven T. Schlotterbeck	Incorporated herein by reference to Exhibit 10.10 to Form 8-K filed on July 31, 2015
* 10.15(a)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and David L. Porges	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended June 30, 2015
* 10.15(b)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and Philip P. Conti	Incorporated herein by reference to Exhibit 10.02 to Form 10-Q for the quarter ended June 30, 2015
* 10.15(c)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and Randall L. Crawford	Incorporated herein by reference to Exhibit 10.03 to Form 10-Q for the quarter ended June 30, 2015
* 10.15(d)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and Lewis B. Gardner	Incorporated herein by reference to Exhibit 10.04 to Form 10-Q for the quarter ended June 30, 2015
* 10.15(e)	Share Repurchase Agreement dated as of May 12, 2015 between the Company and Steven T. Schlotterbeck	Incorporated herein by reference to Exhibit 10.05 to Form 10-Q for the quarter ended June 30, 2015
* 10.16	Form of Indemnification Agreement between the Company and each executive officer and each outside director	Incorporated herein by reference to Exhibit 10.18 to Form 10-K for the year ended December 31, 2008
10.17	Amended and Restated Revolving Credit Agreement dated as of February 18, 2014 among the Company, PNC Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, Wells Fargo Bank, National Association, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Bank of America, N.A., Barclays Bank PLC, Citibank, N.A., JPMorgan Chase Bank, N.A. and SunTrust Bank, as Syndication Agents, and the other lender parties thereto	Incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on February 18, 2014
10.18	First Amended and Restated Limited Liability Company Agreement of Mountain Valley Pipeline, LLC dated as of August 28, 2014 among MVP Holdco, LLC, US Marcellus Gas Infrastructure, LLC, and Mountain Valley Pipeline, LLC. Specific items in this exhibit have been redacted, as marked by three asterisks (***) because confidential treatment for those terms was granted by the SEC. The redacted material has been separately filed with the SEC.	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q/A filed on December 3, 2014
10.19	Assignment and Assumption Agreement dated as of March 30, 2015 among EQT Gathering, LLC, EQT Midstream Partners, LP and MVP Holdco, LLC	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended March 31, 2015

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

INDEX TO EXHIBITS

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

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

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

SIGNATURES

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

EQT CORPORATION

By: /s/ DAVID L. PORGES
David L. Porges
Chief Executive Officer
February 11, 2016

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

/s/ DAVID L. PORGES David L. Porges (Principal Executive Officer)	Chairman and Chief Executive Officer	February 11, 2016
/s/ PHILIP P. CONTI Philip P. Conti (Principal Financial Officer)	Senior Vice President and Chief Financial Officer	February 11, 2016
/s/ THERESA Z. BONE Theresa Z. Bone (Principal Accounting Officer)	Vice President, Finance and Chief Accounting Officer	February 11, 2016
/s/ VICKY A. BAILEY Vicky A. Bailey	Director	February 11, 2016
/s/ PHILIP G. BEHRMAN Philip G. Behrman	Director	February 11, 2016
/s/ KENNETH M. BURKE Kenneth M. Burke	Director	February 11, 2016
/s/ A. BRAY CARY JR. A. Bray Cary, Jr.	Director	February 11, 2016
/s/ MARGARET K. DORMAN Margaret K. Dorman	Director	February 11, 2016
/s/ GEORGE L. MILES, JR. George L. Miles, Jr.	Director	February 11, 2016
/s/ JAMES E. ROHR James E. Rohr	Director	February 11, 2016
/s/ DAVID S. SHAPIRA David S. Shapira	Director	February 11, 2016
/s/ STEPHEN A. THORINGTON Stephen A. Thorington	Director	February 11, 2016
/s/ LEE T. TODD, JR. Lee T. Todd, Jr.	Director	February 11, 2016
/s/ CHRISTINE J. TORETTI	Director	February 11, 2016

Christine J. Toretti

EQT CORPORATION
2016 INCENTIVE PERFORMANCE SHARE UNIT PROGRAM

EQT CORPORATION (the "Company") hereby establishes this EQT CORPORATION 2016 INCENTIVE PERFORMANCE SHARE UNIT PROGRAM (the "Program"), in accordance with the terms provided herein.

WHEREAS, the Company maintains certain long-term incentive award plans, including the EQT Corporation 2014 Long-Term Incentive Plan (as amended from time to time, the "2014 Plan"), for the benefit of its directors and employees, of which the Program is a subset; and

WHEREAS, in order to further align the interests of executives and key employees with the interests of the Company's shareholders, the Company desires to provide long-term incentive benefits through the Program, in the form of awards qualifying as "Performance Awards" under the 2014 Plan.

NOW, THEREFORE, the Company hereby provides for incentive benefits for executives and key employees of the Company and its Affiliates and adopts the terms of the Program on the following terms and conditions:

Section 1. Purpose. The main purpose of the Program is to provide long-term incentive opportunities to executives and key employees to further align their interests with those of the Company's shareholders and with the strategic objectives of the Company. Awards granted hereunder may be earned by achieving relative performance levels against a pre-determined peer group, are forfeited if defined performance levels are not achieved and are subject to negative adjustment if, among other things, certain other performance measures are not attained. By placing a portion of the employee's compensation at risk, the Company has an opportunity to reward exceptional performance or reduce the compensation opportunity when performance does not meet expectations. As a subset of the 2014 Plan, this Program is subject to and shall be governed by the terms and conditions of the 2014 Plan. Capitalized terms used herein and not otherwise defined shall have the meanings given to such terms in the 2014 Plan. The Performance Share Units (as defined in Section 4 below) granted under this Program are intended to meet the performance-based compensation exemption under Section 162(m) of the Code.

Section 2. Effective Date. The effective date of this Program is January 1, 2016 (the "Effective Date"). The Program will remain in effect until the earlier of (i) December 31, 2018 or (ii) the closing date of a Qualifying Change of Control event pursuant to which all awards under the Program are paid in accordance with Section 6, unless otherwise amended or terminated as provided in Section 20. For purposes of this Program, a "Qualifying Change of Control" means a Change of Control (as then defined in the 2014 Plan) unless (a) all outstanding Performance Share Units under the Program are assumed by the surviving entity of the Change of Control (or otherwise equitably converted or substituted in connection with the Change of Control in a manner approved by the Committee) or (b) the Company is the surviving entity of the Change of Control.

Section 3. Eligibility. The Chief Executive Officer of the Company (the "CEO") shall, in his or her sole discretion, select the employees of the Company and its Affiliates who shall be eligible to participate in the Program from those individuals eligible to participate in the 2014 Plan. The CEO's selections will become participants in the Program (the "Participants") only upon approval by the Committee, comprised in accordance with the requirements of the 2014 Plan, to the extent such individuals are, or are expected to be, Covered Employees. In the event that an employee is hired by the Company or an Affiliate during the Performance Period (as defined in Section 5 below), the CEO shall, in his or her sole discretion, determine whether the employee will be eligible to participate in the Program; provided that the Committee must approve all new Participants to the Program who are, or are expected to be, Covered Employees; provided further that individuals who are, or are expected to be, Covered Employees may only become eligible during the first 90 days of the Performance Period.

Section 4. Incentive Performance Share Unit Awards. Awards under the Program are designated in the form of incentive performance share units (as adjusted from time to time in accordance with Section 14, the "Performance Share Units"), which are awards to be settled in shares of the Company's common stock ("Common Stock"), the amount per unit of which is determined by reference to one share of Common Stock. Upon being selected to participate in the Program, each Participant shall be awarded a number of Performance Share Units, which award shall be proposed by the CEO and approved by the Committee. Unless otherwise indicated herein in a particular context, the term "Performance Share Units" includes any Dividend Units (as defined in Section 5 below) accumulated with respect to an award of Performance Share Units, as provided in Section 5.

The Performance Share Units shall be held in bookkeeping accounts on behalf of the Participants and do not represent actual shares of Common Stock. A Participant shall have no right to exchange the Performance Share Units for cash, stock or any other benefit and shall be a mere unsecured creditor of the Company with respect to such Performance Share Units and any future rights to benefits.

Section 5. Performance Conditions. Subject to Section 7, the amount to be distributed to a Participant will be based on the following performance conditions (the "Performance Conditions"): (i) the Company's total shareholder return relative to the peer group's (see Attachment A) total shareholder return calculated as described in subsection (a) below for the Performance Period and (ii) the Company's total sales volume growth calculated as described in subsection (b) below for the Performance Period. For purposes of this Program, the "Performance Period" shall mean the period commencing on January 1, 2016 and continuing thereafter until the earlier of (a) December 31, 2018 and (b) the closing date of a Qualifying Change of Control.

(a) Total Shareholder Return. For purposes of this Program, total shareholder return will be calculated as follows:

Step 1

The "Beginning Point" for the Company and each company in the peer group is defined as one share of common stock with a value equal to the average closing stock price as reported in the Nationally Recognized Reporting Service (as defined below) for the ten (10) consecutive business day period preceding the date of the commencement of the Performance Period, for each company. All references in this Program to the "Nationally Recognized Reporting Service" shall be references to either the print or electronic version of a nationally recognized publication that reports the daily closing stock price of the Company and each member of the peer group.

Step 2

Dividends paid for each company from the beginning of the Performance Period will be cumulatively added to the Beginning Point as additional shares of such company's common stock. The closing price on the last business day of the month in which the record date for the dividend occurs will be used as the basis for determining the number of shares to be added. The resulting total number of shares accumulated during the Performance Period is referred to as the "Total Shares Held at End of Period."

Step 3

Except as provided in the following sentence, the "Ending Point" for each company is defined as Total Shares Held at End of Period for that company times the average of the closing price of such company's common stock as reported in the Nationally Recognized Reporting Service for the last ten (10) business days of the Performance Period for that company. In the event of a Qualifying Change of Control, the "Ending Point" for each company in the peer group is defined as Total Shares Held at End of Period for that company times the average of the closing price of such company's common stock as reported in the Nationally Recognized Reporting Service for the ten (10) business days preceding the closing of the Qualifying Change of Control transaction.

Step 4

Total Shareholder Return ("TSR") will be expressed as a percentage and is calculated by dividing the Ending Point by the Beginning Point and then subtracting 1 from the result. Each company including the Company will be ranked in descending order by the TSR so calculated.

If (i) any company in the peer group announces during the Performance Period that it has entered into an agreement that shall cause its common stock to cease to be publicly traded on the New York Stock Exchange (“NYSE”) or The NASDAQ Stock Market (“NASDAQ”) and does not announce during such period a termination of such agreement or (ii) the common stock of any company in the peer group ceases to be publicly traded on NYSE or NASDAQ during the Performance Period, such company shall be assigned a TSR value of negative 100% for purposes of the Program.

(b) Total Sales Volume Growth. For purposes of this Program, the Company’s total sales volume growth for the Performance Period (the “Total Sales Volume Growth”) shall equal the compound annual growth rate of the Company’s total production sales volumes (Bcfe), as calculated in accordance with Attachment B to this Program, during the Performance Period.

(c) Application of Performance Condition. A Participant’s “Awarded Value” shall be calculated by multiplying (i) the number of such Participant’s Performance Share Units, by (ii) the payout multiple identified on the payout matrix (Attachment B) that corresponds to the Company’s TSR ranking and Total Sales Volume Growth performance on the payout matrix for the Performance Period by (iii) the closing price of the Company’s Common Stock at the end of the Performance Period or, in the case of a Qualifying Change of Control, the closing price of the Company’s Common Stock on the business day immediately preceding the date of the Qualifying Change of Control, in each case as reported in the Nationally Recognized Reporting Service. If Performance Share Units are outstanding on the record date for dividends or other distributions with respect to the Company’s Common Stock, then: (1) if such dividends or distributions are paid on or before the payment date for the Participant’s award as determined in accordance with Section 6 below, the dollar value or fair market value of such dividends or distributions with respect to the number of shares of Common Stock then underlying the Performance Share Units shall be converted into additional Performance Share Units in the Participant’s name (such additional Performance Share Units, the “Dividend Units”), based on the Fair Market Value of the Common Stock as of the date such dividends or distributions are paid; or (2) if such dividends or distributions are paid after the payment date for the Participant’s award as determined in accordance with Section 6 below, the Participant shall receive a cash payment in respect of such dividends or distributions. Any Dividend Units shall be subject to the same performance conditions and transfer restrictions as apply to the Performance Share Units with respect to which they relate.

Payments under the Program are expressly contingent upon achievement of the Performance Conditions.

Section 6. Payment; Overall Limit. Subject to Section 7 and except as provided in the remainder of this Section 6, each Participant's Awarded Value will be distributed in shares of Common Stock no later than March 15, 2019. Subject to Section 7, in the event of a Qualifying Change of Control, the Awarded Value will be distributed in shares of Common Stock on the closing date of the transaction. Notwithstanding the first two sentences of this Section 6, the Committee may determine, in its discretion and for any reason, that the Awarded Value will be paid, in whole or in part, in cash. If a Participant receives payment in the form of Common Stock, the Performance Share Units shall be paid, in whole or in part, in shares of Common Stock equal to the Awarded Value (or portion thereof determined by the Committee) divided by the closing price of the Company's Common Stock at the end of the Performance Period or, in the case of a Qualifying Change of Control, the closing price of the Company's Common Stock on the business day immediately preceding the date of the Qualifying Change of Control. The maximum amount payable to any one Participant under the Program with respect to any one calendar year within the Performance Period shall be the amount set forth and as calculated in the 2014 Plan with respect to Performance Awards, which limit has been approved by the shareholders of the Company. No elections shall be permitted with respect to the timing of any payments.

Section 7. Change of Status. In making decisions regarding employees' participation in the Program and the extent to which awards are payable in the case of an employee whose employment ceases prior to payment, the Committee may consider any factors that it deems to be relevant. Unless otherwise determined by the Committee, and subject to the terms of any written employment-related agreement that a Participant has with the Company (including any confidentiality, non-solicitation, non-competition, change of control or similar agreement), the following shall apply in the case of a Participant whose employment ceases prior to payment of the Awarded Value:

(a) Termination After Change of Control. With respect to any Participant's award under the Program, and notwithstanding Section 9 of the 2014 Plan, in the event that following a Change of Control that is not a Qualifying Change of Control, (i) such Participant's employment is terminated and such termination is a Qualifying Termination (as defined below) or (ii) such Participant resigns for Good Reason (as defined below), in each case prior to the second anniversary of the effective date of the Change of Control, the Participant shall retain all of his or her Performance Share Units, contingent upon achievement of the Performance Conditions set forth in Section 5.

Solely for purposes of this Program, a "Qualifying Termination" shall mean the involuntary termination by the Company (or, as applicable, its successor) of a Participant's employment as a result of (i) the sale, consolidation or full or partial shutdown of a facility, department or business unit; (ii) a position elimination because of a reorganization or lack of work; or (iii) such Participant's death or Disability.

Solely for purposes of this Program, "Good Reason" shall mean a Participant's resignation within 90 days after (but in all cases prior to the second anniversary of such Change of Control): (i) a reduction in such Participant's base salary of 10% or more (unless the reduction is applicable to all similarly situated employees); (ii) a reduction in such Participant's annual short-term bonus target of 10% or more (unless the reduction is applicable to all similarly situated employees); (iii) a significant diminution in such Participant's job responsibilities, duties or authority; (iv) a change in the geographic location of such Participant's primary reporting location of more than 50 miles; and/or (v) any other action or inaction that constitutes a material breach by the Company of such Participant's award agreement under the Program.

A termination by a Participant shall not constitute termination for Good Reason unless such Participant first delivers to the General Counsel of the Company written notice: (i) stating that such Participant intends to resign for Good Reason pursuant to his or her award agreement; and (ii) setting forth with specificity the occurrence deemed to give rise to a right to terminate for Good Reason (which notice must be given no later than 90 days after the initial occurrence of such event). The Company shall have a reasonable period of time (not less than 30 days) to take action to correct, rescind or substantially reverse the occurrence supporting termination for Good Reason as identified by such Participant. Failure by the Company to act or respond to the written notice shall not be deemed to be an admission that Good Reason exists.

(b) Retirement and Resignation. If a Participant's employment is terminated voluntarily (including retirement) or such termination is a Qualifying Termination and the Participant remains on the board of directors of the Company, EQT Midstream Services, LLC or EQT GP Services, LLC following such termination of employment, then, notwithstanding any prior agreement to the contrary (including an agreement to enter into a form of an executive alternative work arrangement), the Participant shall retain all of his or her Performance Share Units, contingent upon achievement of the Performance Conditions set forth in Section 5, for as long as the Participant remains on such board of directors, in which case any references herein to such Participant's employment shall be deemed to include his or her continued service on such board. Except as set forth in the preceding sentence and subsection (a) above, a Participant's Performance Share Units shall be forfeited upon his or her retirement or resignation as an employee of the Company or an Affiliate.

(c) Other Termination. If a Participant's employment is involuntarily terminated and such termination is not a Qualifying Termination, the Participant's Performance Share Units shall be forfeited. Except as provided in subsections

(a) and (b) above, if the termination is a Qualifying Termination, the Participant (or the Participant's estate or beneficiary) will retain his or her Performance Share Units, contingent upon (i) the Participant executing and not revoking a full release of claims in a form acceptable to the Company within 30 days of his or her Qualifying Termination, and (ii) achievement of the Performance Conditions set forth in Section 5, as follows, and the remainder shall be forfeited:

Termination Date	Percent Retained
Prior to January 1, 2017	0%
January 1, 2017 – December 31, 2017	25%
January 1, 2018 – December 31, 2018	50%

(d) Change of Position. Except as provided in subsections (a) and (b) above, a Participant whose position within the Company or an Affiliate changes to a non-Program eligible position as determined by the Company's Chief Human Resources Officer (or if such Participant is an executive officer of the Company, as determined by the Committee) but who remains employed through the date of payment of the Awarded Value will retain his or her Performance Share Units, contingent upon achievement of the Performance Conditions set forth in Section 5, as follows, and the remainder shall be forfeited:

Change of Position Date	Percent Retained
Prior to January 1, 2017	0%
January 1, 2017 – December 31, 2017	25%
January 1, 2018 – December 31, 2018	50%

In such events, any Performance Share Units that are retained shall be payable at the time specified in Section 6. Notwithstanding any other provisions of the Program, Participants shall have no vested rights to any Performance Share Units prior to payment.

Section 8. Administration of the Plan. The Committee has responsibility for all aspects of the Program's administration, including:

- Determining and certifying, in writing, the extent to which the Performance Conditions have been achieved prior to any payments under the Program,
- Ensuring that the Program is administered in accordance with its provisions and the 2014 Plan,
- Approving Program Participants,

- Authorizing Performance Share Unit awards to Participants,
- Adjusting Performance Share Unit awards to account for extraordinary events,
- Serving as the final arbiter of any disagreement between Program Participants, Company management, Program administrators, and any other interested parties to the Program, and
- Maintaining final authority to amend, modify or terminate the Program at any time.

Notwithstanding anything to the contrary in this Program, the Committee shall at all times retain the discretion with respect to all awards under this Program to reduce, eliminate, or determine the source of, any payment or award hereunder without regard to any particular factors specified in this Program. The interpretation and construction by the Committee of any provisions of the Program or of any adjusted Performance Share Units shall be final. No member of the Committee shall be liable for any action or determination made in good faith on the Program or any Performance Share Units thereunder. The Committee may designate another party to administer the Program, including Company management or an outside party to the extent permitted under Code Section 162(m). All conditions of the Performance Share Units must be approved by the Committee. As early as practicable prior to or during the Performance Period, the Committee shall approve the number of Performance Share Units to be awarded to each Participant. The associated terms and conditions of the Program will be communicated to Participants as close as administratively practicable to the date an award is made. The Participants will acknowledge receipt of the participant agreement and will agree to the terms of this Program in accordance with the Company's procedures.

Section 9. Limitation of Rights. The Performance Share Units do not confer to Participants or their beneficiaries, executors or administrators any rights as shareholders of the Company (including voting and other shareholder rights) unless and until shares of Common Stock are in fact registered to or on behalf of a Participant in connection with the payment of the Performance Share Units. Upon conversion of the Performance Share Units into shares of Common Stock, a Participant will obtain full voting and other rights as a shareholder of the Company.

Section 10. Tax Consequences to Participants/Payment of Taxes.

(a) It is intended that: (i) until the Performance Conditions are satisfied, a Participant's right to payment for an award under this Program shall be considered to be subject to a substantial risk of forfeiture in accordance with those terms as defined or referenced in Sections 83(a), 409A and 3121(v)(2) of the Code; (ii) the Awarded Value shall be subject to employment taxes only upon the satisfaction of the Performance Conditions; and (iii) until the Awarded Value is actually paid to a Participant, the Participant shall have merely an unfunded, unsecured promise to be paid the benefit, and such unfunded promise shall not consist of a transfer of "property" within the meaning of Code Section 83. It is further intended that Participants will not be in actual or constructive receipt of compensation with respect to the Performance Share Units within the meaning of Code Section 451 until the Awarded Value is paid.

(b) The Company or any Affiliate employing the Participant has the authority and the right to deduct or withhold, or require a Participant to remit to the employer, an amount sufficient to satisfy federal, state, and local taxes (including the Participant's FICA obligation) required by law to be withheld with respect to any taxable event arising as a result of an award under the Program. With respect to withholding required upon any taxable event arising as a result of an award, the employer may satisfy the tax withholding required by withholding shares of Common Stock having a Fair Market Value as of the date that the amount of tax to be withheld is to be determined as nearly equal as possible to (but no more than) the total minimum statutory tax required to be withheld. The obligations of the Company under this Program will be conditioned upon such payment or arrangements, and the Company, and, where applicable, its Affiliates will, to the extent permitted by law, have the right to deduct any such taxes from any payment of any kind otherwise due to a Participant.

Section 11. Recoupment Policy. Any shares of Common Stock distributed or amounts paid to a Participant under the Program, and any cash or other benefit acquired upon the sale of shares of Common Stock distributed to a Participant under the Program, shall be subject to the terms and conditions of any compensation recoupment policy adopted from time to time by the Company's board of directors or any committee of such board, to the extent such policy is applicable to this Program and the Participant.

Section 12. Nonassignment. A Participant shall not be permitted to assign, alienate or otherwise transfer his or her Performance Share Units, and any attempt to do so shall be void.

Section 13. Impact on Benefit Plans. Payments under the Program shall not be considered as earnings for purposes of the Company's or its Affiliates' qualified retirement plans or any other retirement, compensation or benefit plan or program of the Company or its Affiliates unless specifically provided for and defined under such other plan or program. Nothing herein shall prevent the Company or its Affiliates from maintaining additional compensation plans and arrangements; provided, however, that no payments shall be made under such plans and arrangements if the effect thereof would be the payment of compensation otherwise payable under this Program regardless of whether the Performance Conditions were attained.

Section 14. Successors; Changes in Stock. The obligations of the Company under the Program shall be binding upon the successors and assigns of the Company. In the event of any spin-off, split-off or split-up, or dividend in partial liquidation, dividend in property other than cash or Common Stock, or extraordinary distribution to holders of Common Stock, each Participant's Performance Share Units shall be appropriately adjusted to prevent dilution or enlargement of the rights of Participants that would otherwise result from any such transaction, provided such adjustment shall be consistent with Section 409A of the Code.

In the case of a Change of Control, any obligation under the Program shall be handled in accordance with the terms of Sections 5 and 6 hereof. In any case not constituting a Change of Control in which the Common Stock is changed into or becomes exchangeable for a different number or kind of shares of stock or other securities of the Company or another corporation, or cash or other property, whether through reorganization, reclassification, recapitalization, stock split-up, combination of shares, merger or consolidation, then (i) the Awarded Value shall be calculated based on the closing price of such common stock on the closing date of the transaction on the principal market on which such common stock is traded, and (ii) there shall be substituted for each Performance Share Unit constituting an award the number and kind of shares of stock or other securities (or cash or other property) into which each outstanding share of Common Stock shall be so changed or for which each such share shall be exchangeable. In the case of any such adjustment, the Performance Share Units shall remain subject to the terms of the Program and the 2014 Plan.

Section 15. Notice. Except as may be otherwise provided by the 2014 Plan or determined by the Committee and communicated to a Participant, notices and communications hereunder must be in writing and shall be deemed sufficiently given if either hand-delivered or if sent by fax or overnight courier, or by postage paid first class mail. Notices sent by mail shall be deemed received five (5) business days after mailed, but in no event later than the date of actual receipt. Notices shall be directed, if to a Participant, at such Participant's address indicated by the Company's records or, if to the Company, at the Company's principal executive office, Attention: Corporate Director, Compensation and Benefits.

Section 16. Dispute Resolution. Any dispute regarding the payment of benefits under this the Program or the 2014 Plan shall be resolved in accordance with the EQT Corporation Long-Term Incentive Dispute Resolution Procedures as in effect at the time of such dispute. A copy of such procedures is available on the Fidelity NetBenefits website, which can be found at www.netbenefits.fidelity.com.

Section 17. Applicable Law. This Program shall be governed by and construed under the laws of the Commonwealth of Pennsylvania without regard to its conflict of law provisions.

Section 18. Severability. In the event that any one or more of the provisions of this Program shall be held to be invalid, illegal or unenforceable, the validity, legality or enforceability of the remaining provisions shall not in any way be affected or impaired thereby.

Section 19. Headings. The descriptive headings of the Sections of this Program are inserted for convenience of reference only and shall not constitute a part of this Program.

Section 20. Amendment or Termination of this Program. This Program may be amended, suspended or terminated by the Company at any time upon approval by the Committee and following a determination that the Program is no longer meaningful in relation to the Company's strategy. Notwithstanding the foregoing, (i) no amendment, suspension or termination shall adversely affect a Participant's rights to his or her award after the date of the award; provided, however, that the Company may amend this Program from time to time without any Participant's consent to the extent deemed to be necessary or appropriate, in its sole discretion, to effect compliance with Code Section 409A or any other provision of the Code, including regulations and interpretations thereunder, which amendments may result in a reduction of benefits provided hereunder and/or other unfavorable changes to Participants, (ii) no amendment may alter the time of payment as provided in Section 6 of the Program, and (iii) no amendment may be made following a Change of Control.

Attachment A

2016 Incentive Performance Share Unit Program

Peer Group

CABOT OIL & GAS CORPORATION
CHESAPEAKE ENERGY CORPORATION
CIMAREX ENERGY CO.
CONCHO RESOURCES INC.
CONSOL ENERGY INC.
CONTINENTAL RESOURCES, INC.
ENERGEN CORPORATION
EOG RESOURCES, INC.
EXCO RESOURCES, INC.
MARATHON OIL CORPORATION
NATIONAL FUEL GAS COMPANY
NEWFIELD EXPLORATION COMPANY
NOBLE ENERGY, INC.
ONEOK, INC.
PIONEER NATURAL RESOURCES COMPANY
QEP RESOURCES, INC.
RANGE RESOURCES CORPORATION
SM ENERGY COMPANY
SOUTHWESTERN ENERGY COMPANY
SPECTRA ENERGY CORP
ULTRA PETROLEUM CORP.
WHITING PETROLEUM CORPORATION

Attachment B

2016 Incentive Performance Share Unit Program

Payout Matrix

		Payout Factor*							
Total Sales Volume Growth**	25% Compound Annual Growth Rate	**.75**	**1.00**	**1.50**	**2.00**	**2.40**	**2.60**	**2.80**	**3.00**
	20% Compound Annual Growth Rate	**.55**	**.95**	**1.35**	**1.75**	**2.15**	**2.35**	**2.55**	**2.75**
	15% Compound Annual Growth Rate	**.30**	**.70**	**1.10**	**1.50**	**1.90**	**2.10**	**2.30**	**2.50**
	5% Compound Annual Growth Rate	**.00**	**.20**	**.60**	**1.00**	**1.40**	**1.60**	**1.80**	**2.00**
	0% Compound Annual Growth Rate	**.00**	**.00**	**.00**	**.50**	**.90**	**1.10**	**1.30**	**1.50**
		23-21	**20-18**	**17-15**	**14-12**	**11-10**	**9-7**	**6-4**	**3-1**
		Total Shareholder Return Rank							

* Payout Factor shall be interpolated between stated levels of Total Sales Volume Growth.

** Total Sales Volume Growth is equal to the compound annual growth rate ("CAGR") of the Company's total production sales volumes (Bcfe) during the Performance Period, calculated as follows:

$$CAGR = \left(\frac{EndingVolume}{BeginningVolume}\right)^{\left(\frac{1}{Period}\right)} - 1$$

where:

- "BeginningVolume" is equal to the Company's total production sales volumes (Bcfe) during 2015 as reported in the Company's 2015 annual report on Form 10-K.
- "EndingVolume" is equal to:
  - In the event the Performance Period expires on December 31, 2018 and no Qualifying Change of Control occurs prior to the filing date of the Company's 2018 annual report on Form 10-K (the "2018 Form 10-K"), the Company's total production sales volumes (Bcfe) during 2018 as reported in the 2018 Form 10-K.

- Except as set forth in the following paragraph, in the event of a Qualifying Change of Control prior to the filing date of the 2018 Form 10-K, the sum of the Company's total production sales volumes (Bcfe) for the four (4) quarters actually completed which precede the closing date of the Qualifying Change of Control and for which a Form 10-Q (or, in the case of the fourth quarter of any such year, a Form 10-K), is filed prior to such closing date. The total production sales volumes (Bcfe) for such quarters shall be the total production sales volumes as reported in the applicable Forms 10-Q (and, in the case of the fourth quarter of any year, the total production sales volumes calculated for the fourth quarter by reducing the annual total production sales volumes reported in the applicable Form 10-K by the quarterly total production sales volumes reported in the Forms 10-Q for the first three quarters of such year).

- In the event of a Qualifying Change of Control prior to the filing date of the Company's 2016 annual report on Form 10-K, the sum of the Company's total production sales volumes (Bcfe) for the quarters actually completed during the Performance Period which precede the closing date of the Qualifying Change of Control and for which Forms 10-Q were filed prior to such closing date, annualized for 2016 total production sales volumes. By way of example only, the quarterly total production sales volumes would be annualized as follows:

  Example: If a Qualifying Change of Control occurred during the third quarter of 2016 on or following the filing date of the Company's quarterly report on Form 10-Q for the second quarter of 2016, and the Company's total production sales volumes for the first two quarters totaled 250 Bcfe, the EndingVolume, or annualized 2016 total production sales volumes, would equal 500 Bcfe.

- "Period" is equal to (i) in the event the Performance Period expires on December 31, 2018 and no Qualifying Change of Control occurs prior to the filing date of the 2018 Form 10-K, three (3) years, or (ii) in the event of a Qualifying Change of Control prior to the filing date of the 2018 Form 10-K, the number of calendar quarters actually completed during the Performance Period and for which a Form 10-Q (or, in the case of the fourth quarter of any year, a Form 10-K) is filed prior to the closing date of the Qualifying Change of Control, expressed as an annualized period. For example, if the closing date of a Qualifying Change of Control occurs on August 1, 2017 and the Company filed its Form 10-Q for the second quarter of 2017 prior to such date, the "Period" would equal one and one-half (1.5) years.

For the avoidance of doubt, Total Sales Volume Growth (i) is determined solely by the volumes reported, regardless of any subsequently identified prior period adjustment; (ii) represents the Company's interest in natural gas, natural gas liquids and oil sales during the applicable period; (iii) does not include gathered volumes; and (iv) will be measured at the sales meter.

PARTICIPANT AWARD AGREEMENT
(2016 Incentive PSU Program)

[Grant Date], 2016

Dear [Name]:

Pursuant to the terms and conditions of the EQT Corporation 2014 Long-Term Incentive Plan (as amended from time to time, the “Plan”) and the 2016 Incentive Performance Share Unit Program (the “Program”), effective January 1, 2016, the Management Development and Compensation Committee (the “Committee”) of the Board of Directors of EQT Corporation (the “Company”) grants you **«NumberUnits» Target Performance Share Units** (the “Award”), the value of which is determined by reference to the Company’s common stock. The terms and conditions of the Award, including, without limitation, vesting and distribution, shall be governed by the provisions of this Participant Award Agreement and the Program document attached hereto as Exhibit A; provided that the Award is also subject to the terms and limits included within the Plan. The Committee retains the discretion to distribute the Award in cash, Company stock or any combination thereof.

The terms contained in the Plan and the Program are hereby incorporated into and made a part of this Participant Award Agreement, and this Participant Award Agreement shall be governed by and construed in accordance with the Program and the Plan. In the event of any actual or alleged conflict between (a) the provisions of the Plan and the provisions of this Participant Award Agreement, the provisions of the Plan shall be controlling and determinative, and (b) the provisions of this Participant Award Agreement and the terms of any written employment-related agreement that you have with the Company (including any confidentiality, non-solicitation, non-competition, change of control or similar agreement), the terms of such employment-related agreement shall be controlling and determinative.

You may access important information about the Company and the Plan through the Company’s website. Copies of the Plan and Plan Prospectus can be found by logging into the Fidelity NetBenefits website, which can be found at www.netbenefits.fidelity.com, and clicking on the “Stock Plans” tab and then following the prompts for your Plan documents. Copies of the Company’s most recent Annual Report on Form 10-K, Proxy Statement and other information generally delivered to the Company’s shareholders can be found at www.eqt.com by clicking on the “Investors” link on the main page and then “SEC Filings.” Paper copies of such documents are available upon request made to the Company’s Corporate Secretary.

Your Award under the Program will be effective only if, no later than 45 days after the date of this Participant Award Agreement, (a) you accept your Award through the Fidelity NetBenefits website and (b) to the extent you are not already subject to a confidentiality, non-solicitation and non-competition agreement with the Company, you execute a confidentiality, non-solicitation and non-competition agreement acceptable to the Company.

When you accept your Award through the Fidelity NetBenefits website, you shall be deemed to have (a) acknowledged receipt of this Award granted on the date of this Participant Award Agreement (the terms of which are subject to the terms and conditions of this Participant Award Agreement, the Program document and the Plan) and copies of this Participant Award Agreement, the Program document and the Plan, and (b) agreed to be bound by all the provisions of this Participant Award Agreement, the Program document and the Plan.

Exhibit 10.12(b)

AMENDMENT TO AMENDED AND RESTATED CONFIDENTIALITY, NON-SOLICITATION AND NON-COMPETITION AGREEMENT

THIS AMENDMENT TO AMENDED AND RESTATED CONFIDENTIALITY, NON-SOLICITATION AND NON-COMPETITION AGREEMENT ("Non-Compete Amendment") is made effective as of January 1, 2016 (the "Effective Date"), by and between EQT Corporation (together with its subsidiary companies, the "Company") and Randall L. Crawford ("Employee") and amends the Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of July 29, 2015, by and between the Company and Employee ("Agreement").

W I T N E S S E T H:

WHEREAS, the Company and Employee entered into the Agreement on or about July 29, 2015;

WHEREAS, the Agreement authorizes the parties to amend the Agreement by a written instrument signed by both parties;

WHEREAS, the Company and Employee express their intent to modify the Agreement in accordance with the terms of this Non-Compete Amendment;

NOW, THEREFORE, the Company and Employee, intending to be legally bound, hereby agree as follows:

1. In exchange for the mutual covenants set forth in the Executive Alternative Work Arrangement Employment Agreement attached hereto as Exhibit A, the parties agree to amend the Agreement by deleting paragraph 9 of the Agreement and substituting the following paragraph:

> 9. Executive Alternative Work Arrangement Employment Status. Employee has elected to participate in the “Executive Alternative Work Arrangement” program upon Employee’s voluntary discontinuance of full-time status. The Executive Alternative Work Arrangement classification will be automatically assigned to Employee if and when Employee incurs a termination of employment that meets each of the following conditions (an “Eligible Termination”): (a) Employee’s employment is terminated by the Company for any reason other than Cause ***or*** Employee gives the Company (delivered to the Vice President and Chief Human Resources Officer) at least 90 days’ advance written notice of Employee’s intention to discontinue employment, (b) Employee is a board-designated executive officer in good standing with EQT Corporation as of the time of his/her termination of employment, and (c) Employee’s employment shall not have been terminated by Employee for Good Reason. The terms and conditions of Employee’s Executive Alternative Work Arrangement are set

forth in the form of Executive Alternative Work Arrangement Employment Agreement attached as Exhibit A. Employee agrees to execute an Executive Alternative Work Arrangement Employment Agreement, in a form substantially similar to the one attached as Exhibit A, within 90 days prior to Employee's relinquishment of full-time status, which agreement will become effective automatically on the day following Employee's Eligible Termination. Without limiting the foregoing, Employee agrees that he/she will not be eligible for the Executive Alternative Work Arrangement, including the post-employment benefits described therein if Employee's termination of employment is not an Eligible Termination.

2. This Non-Compete Amendment, including Exhibit A attached hereto, is hereby incorporated into the Agreement. Except as expressly amended by this Non-Compete Amendment, all provisions of the Agreement shall remain in full force and effect.

3. This Non-Compete Amendment shall be governed by and construed in accordance with the laws of the Commonwealth of Pennsylvania.

4. The parties acknowledge that this Non-Compete Amendment is a written instrument and that by their signatures below they are agreeing to the terms and conditions contained in this Non-Compete Amendment.

IN WITNESS WHEREOF, the parties hereto have duly executed and delivered this Non-Compete Amendment as of the date first above written.

EQT Corporation

By: /s/ Charlene Petrelli

Name: Charlene Petrelli

Title: Vice President &
Chief Human Resources Officer

Employee:

/s/ Randall L. Crawford
Randall L. Crawford

EXHIBIT A

EXECUTIVE ALTERNATIVE WORK ARRANGEMENT EMPLOYMENT AGREEMENT

This is an Executive Alternative Work Arrangement Employment Agreement (“Agreement”) entered into between EQT Corporation (together with its subsidiaries, “EQT” or the “Company”) and Randall L. Crawford (“Employee”).

WHEREAS, Employee is an executive officer of EQT who desires to relinquish that status and discontinue full-time employment with EQT but continue employment with EQT on a part-time basis; and

WHEREAS, EQT is interested in continuing to retain the services of Employee on a part-time basis for at least 100 (but no more than 400) hours per year; and

WHEREAS, Employee has elected to modify his/her employment status to Executive Alternative Work Arrangement;

NOW, THEREFORE, in consideration of the respective representations, acknowledgements, and agreements of the parties set forth herein, and intending to be legally bound, the parties agree as follows:

1. The term of this Agreement is for the one-year period commencing on the day after Employee’s full-time status with EQT ceases. During that period, Employee will hold the position of an Executive Alternative Work Arrangement employee of EQT. Employee’s status as Executive Alternative Work Arrangement (and this one-year Agreement) will automatically renew annually unless either party terminates this Agreement by written notice to the other not less than 30 days prior to the renewal date. The automatic annual renewals of this Agreement will cease, however, at the end of five years of Executive Alternative Work Arrangement employment status.

2. During each one-year period in Executive Alternative Work Arrangement employment status, Employee is required to provide no less than 100 hours of service to EQT. During each one-year period, Employee will also make himself/herself available for up to 300 additional hours of service upon request from the Company. All such hours of service will occur during the Company’s regularly scheduled business hours (unless otherwise agreed by the parties), and no more than fifty (50) hours will be scheduled per month (unless otherwise agreed by the parties).

3. Employee shall be paid an hourly rate for Employee’s actual services provided under this Agreement. The hourly rate shall be Employee’s annual base salary in effect immediately prior to Employee’s change in employee classification to Executive Alternative Work Arrangement employment status divided by 2080. Employee shall submit monthly time sheets in a form agreed upon by the parties, and Employee will be paid on regularly scheduled payroll dates in accordance with the Company’s standard payroll practices following submission of his/her time sheets. Notwithstanding the foregoing, in the event that during any one-year

period in Executive Alternative Work Arrangement employment status, EQT requests Employee to provide less than 100 hours of service, EQT shall pay Employee for a minimum of 100 hours of service (regardless of the actual number of hours of service), with any remaining amount owed payable on the next regularly scheduled payroll date following the end of the applicable one-year period. If either party terminates the Executive Alternative Work Arrangement prior to the fifth anniversary hereof, no additional compensation will be paid to Employee pursuant to this Section 3.

4. Employee shall be eligible to continue to participate in the group medical (including prescription drug), dental and vision programs in which Employee participated immediately before the classification change to Executive Alternative Work Arrangement (as such plans might be modified by the Company from time-to-time), but Employee will be required to pay 100% of the Company's premium (or premium equivalent) rates to the carriers (the full active employee premium rates – both the employee portion and the employer portion - as adjusted year-to-year) for participation in such group insurance programs. If Employee completes five years of Executive Alternative Work Arrangement employment status or if the Company terminates the Executive Alternative Work Arrangement prior to the fifth anniversary hereof other than pursuant to paragraph 17 hereof, Employee will be allowed to participate in such group insurance programs at 102% of the then-applicable full active employee premium rates (both the employee portion and the employer portion) until the earlier of: (i) Employee becomes eligible to receive Medicare benefits and (ii) Employee reaches age 70, even though Employee is no longer employed by EQT. Employee acknowledges that, to the extent, if at all, the Company's cost to include Employee in the group insurance programs pursuant to this paragraph exceeds the cost paid by the Employee, the benefits provided hereunder may result in taxable income to the Employee. All amounts required to be paid by Employee pursuant to this paragraph shall be due not later than 30 days after written notice thereof is sent by the Company. Company may terminate the benefits provided under this Agreement upon 30 days written notice of any failure by Employee to timely perform his/her payment obligation hereunder, unless such failure is earlier cured.

5. During the term of this Agreement, Employee will continue to receive service credit for purposes of calculating the value of the Medical Spending Account.

6. Employee shall not be eligible to participate in the Company's life insurance and disability insurance programs, 401(k) Plan, ESPP, or any other retirement or welfare benefit programs or perquisites of the Company. Likewise, Employee shall not receive any paid vacation, paid holidays or car allowance.

7. Employee is not eligible to receive bonus payments under any short-term incentive plans of EQT, and is not eligible to receive any new grants under EQT's long-term incentive plans, programs or arrangements.

8. Effective not later than the commencement of this Executive Alternative Work Arrangement, Employee shall be deemed to have retired for purposes of measuring vesting and/or post-termination exercise periods of all forms of long term incentive awards. The timing of

any payments for such awards will be as provided in the underlying plans, programs or arrangements and is subject to any required six-month delay in payment if Employee is a "specified employee" under Section 409A of the Internal Revenue Code of 1986, as amended (the "Code") at the time of Employee's separation from service, with respect to payments made by reason of Employee's separation from service. Nothing in this paragraph 8, or in paragraph 7, shall prevent (a) the continued vesting of previously granted long-term incentive awards to the extent the award agreement therefore expressly contemplates continued vesting while the recipient serves as a member of the Board of Directors of the Company or an affiliate or (b) grants of non-employee director awards to an individual solely because such individual serves on the Board of Directors of the Company or an affiliate. Notwithstanding anything contained herein to the contrary, any special vesting and/or payment provisions applicable to Employee's long-term incentive awards pursuant to that certain Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement between EQT and Employee dated July 29, 2015 (as amended from time to time, the "Non-Competition Agreement") shall apply and be given effect.

9. The Company shall either pay on behalf of Employee or reimburse Employee for the cost of (i) monthly dues for one country club and one dining club (such clubs to be approved by the Company's Chief Executive Officer), and (ii) executive level physicals (currently "gold" level) and related health and wellness services for Employee and Employee's spouse (up to a maximum annual benefit of $15,000), in each case during the term of this Agreement or, if the Company terminates the Executive Alternative Work Arrangement prior to the fifth anniversary hereof other than pursuant to paragraph 17 hereof, through the fifth anniversary hereof in accordance with and on the dates specified in the Company's policies; *provided, however,* that no such payments or reimbursements shall be made until the first day following the six-month anniversary of Employee's separation from service if Employee is a specified employee at the time of separation from service, all within the meaning of Section 409A of the Code; *provided, further,* that to the extent reimbursed or paid, all reimbursements and payments with respect to expenses incurred within a particular year shall be made no later than the end of Employee's taxable year following the taxable year in which the expense was incurred. The amount of payments or reimbursable expenses incurred in one taxable year of Employee shall not affect the amount of reimbursable expenses in a different taxable year, and such payments or reimbursement shall not be subject to liquidation or exchange for another benefit.

10. Employee shall continue to have mobile telephone service and reasonable access to the Company's Help Desk during the term of this Agreement or, if the Company terminates the Executive Alternative Work Arrangement prior to the fifth anniversary hereof other than pursuant to paragraph 17 hereof, through the fifth anniversary hereof; provided, however, if the provision of such service will result in taxable income to Employee, then no such taxable service shall be provided until the first day following the six-month anniversary of Employee's separation from service if Employee is a specified employee at the time of separation from service, all within the meaning of Section 409A of the Code.

11. Employee shall receive tax, estate and financial planning services from providers approved in advance by the Company during the term of this Agreement or, if the Company

terminates the Executive Alternative Work Arrangement prior to the fifth anniversary hereof other than pursuant to paragraph 17 hereof, through the fifth anniversary hereof, in amount not to exceed $15,000 per calendar year, to be paid directly by the Company in accordance with and on the dates specified in the Company's policies; *provided, however,* that no such payments or reimbursements shall be made until the first day following the six-month anniversary of Employee's separation from service if Employee is a specified employee at the time of separation from service, all within the meaning of Section 409A of Code; *provided, further,* that to the extent reimbursed or paid, all reimbursements and payments with respect to expenses incurred within a particular year shall be made no later than the end of Employee's taxable year following the taxable year in which the expense was incurred. The amount of payments or reimbursable expenses incurred in one taxable year of Employee shall not affect the amount of payments or reimbursable expenses in a different taxable year, and such payments or reimbursement shall not be subject to liquidation or exchange for another benefit.

12. During the term of this Agreement, Employee shall maintain an ownership level of Company stock equal to not less than one-half of the value last required as a full-time Employee. In the event that at any time during the term of this Agreement Employee does not maintain the required ownership level, Employee shall promptly notify the Company and increase his or her ownership to at least the required level. Any failure of Employee to maintain at least the required ownership level for more than three months during the term of this Agreement shall constitute and be deemed to be an immediate termination by Employee of his or her Executive Alternative Work Arrangement.

13. This Agreement sets forth all of the payments, benefits, perquisites and entitlements to which Employee shall be entitled upon assuming Executive Alternative Work Arrangement employment status. Employee shall not be entitled to receive any gross-up payments for any taxes or other amounts with respect to amounts payable under this Agreement.

14. Nothing in this Agreement shall prevent or prohibit the Company from modifying any of its employee benefits plans, programs, or policies.

15. <u>Non-Competition and Non-Solicitation</u>. The covenants as to non-competition and non-solicitation contained in Section 1, and as to notification of subsequent employment in Section 12, in each case of the Non-Competition Agreement shall remain in effect throughout Employee's employment with EQT in Executive Alternative Work Arrangement employment status and for a period of twenty-four (24) months, in the case of non-competition covenants; twenty-four (24) months, in the case of non-solicitation covenants relating to customers and prospective customers; and thirty-six (36) months, in the case of non-solicitation covenants relating to employees, consultants, vendors or independent contractors, in each case after the termination of Employee's employment as an Executive Alternative Work Arrangement employee. It is understood and agreed that if Employee's employment as an Executive Alternative Work Arrangement employee terminates for any reason in the midst of any one-year term period as provided under this Agreement (including, without limitation, a termination pursuant to Sections 4, 12 or 17 of this Agreement), the covenants as to non-competition and non-solicitation contained in the Non-Competition Agreement shall remain in effect throughout

the remainder of that one-year term and for a period of twenty-four (24) months, in the case of non-competition covenants, and thirty-six (36) months, in the case of non-solicitation covenants, months thereafter.

16. Confidential Information and Non-Disclosure. Employee acknowledges and agrees that Employee's employment by the Company necessarily involves Employee's knowledge of and access to confidential and proprietary information pertaining to the business of the Company. Accordingly, Employee agrees that at all times during the term of this Agreement and for as long as the information remains confidential after the termination of Employee's employment, Employee will not, directly or indirectly, without the express written authority of the Company, unless directed by applicable legal authority having jurisdiction over Employee, disclose to or use, or knowingly permit to be so disclosed or used, for the benefit of Employee, any person, corporation or other entity other than the Company, (i) any information concerning any financial matters, employees of the Company, customer relationships, competitive status, supplier matters, internal organizational matters, current or future plans, or other business affairs of or relating to the Company, (ii) any management, operational, trade, technical or other secrets or any other proprietary information or other data of the Company, or (iii) any other information related to the Company which has not been published and is not generally known outside of the Company. Employee acknowledges that all of the foregoing constitutes confidential and proprietary information, which is the exclusive property of the Company. Nothing in this Section 16 prohibits Employee from reporting possible violations of federal, state, or local law or regulation to any governmental agency or entity, or from making other disclosures that are protected under the whistleblower provisions of federal, state, or local law or regulation.

17. EQT may terminate this Agreement and Employee's employment at any time for Cause. Solely for purposes of this Agreement, "Cause" shall mean: (i) Employee's conviction of a felony, a crime of moral turpitude or fraud or Employee having committed fraud, misappropriation or embezzlement in connection with the performance of his/her duties; (ii) Employee's willful and repeated failures to substantially perform assigned duties; or (iii) Employee's violation of any provision of this Agreement or express significant policies of the Company. If the Company terminates Employee's employment for Cause, the Company shall give Employee written notice setting forth the reason for his/her termination not later than 30 days after such termination.

18. Except as otherwise provided herein, in the event of any controversy, dispute or claim arising out of, or relating to this Agreement, or the breach thereof, or arising out of any other matter relating to the Employee's employment with EQT or the termination of such employment, EQT may seek recourse for injunctive relief to the courts having jurisdiction thereof and if any relief other than injunctive relief is sought, EQT and the Employee agree that such underlying controversy, dispute or claim shall be settled by arbitration conducted in Pittsburgh, Pennsylvania in accordance with this Section 18 of this Agreement and the Commercial Arbitration Rules of the American Arbitration Association ("AAA"). The matter shall be heard and decided, and awards, if any, rendered by a panel of three (3) arbitrators (the "Arbitration Panel"). EQT and the Employee shall each select one arbitrator from the AAA

National Panel of Commercial Arbitrators (the "Commercial Panel") and AAA shall select a third arbitrator from the Commercial Panel. Any award rendered by the Arbitration Panel shall be final, binding and confidential as between the parties hereto and their heirs, executors, administrators, successors and assigns, and judgment on the award may be entered by any court having jurisdiction thereof.

19. EQT shall have the authority and the right to deduct or withhold, or require Employee to remit to EQT, an amount sufficient to satisfy federal, state, and local taxes (including Employee's FICA obligation) required by law to be withheld with respect to any payment or benefit provided pursuant to this Agreement. The obligations of EQT under this Agreement will be conditioned on such payment or arrangements and EQT will, to the extent permitted by law, have the right to deduct any such taxes from any payment of any kind otherwise due to Employee.

20. It is understood and agreed that upon Employee's discontinuation of full-time employment and transition to Executive Alternative Work Arrangement employment status hereunder, Employee has no continuing rights under Section 3 of the Non-Competition Agreement and such section shall have no further force or effect.

21. The provisions of this Agreement are severable. To the extent that any provision of this Agreement is deemed unenforceable in any court of law, the parties intend that such provision be construed by such court in a manner to make it enforceable.

22. This Agreement shall be binding upon and inure to the benefit of the successors and assigns of the Company.

23. This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Pennsylvania without regard to conflict of law principles.

24. This Agreement supersedes all prior agreements and understandings between EQT and Employee with respect to the subject matter hereof (oral or written), including but not limited to Section 3 of the Non-Competition Agreement. It is understood and agreed, however, that the covenants as to non-competition, non-solicitation, confidentiality and nondisclosure contained in Sections 1 and 2 of the Non-Competition Agreement remain in effect as modified herein, along with the provisions in Sections 4, 5, 6, 7, 8, 11 and 12 of the Non-Competition Agreement.

25. This Agreement may not be changed, amended, or modified except by a written instrument signed by both parties, provided that the Company may amend this Agreement from time to time without Employee's consent to the extent deemed necessary or appropriate, in its sole discretion, to effect compliance with Section 409A of the Code, including regulations and interpretations thereunder, which amendments may result in a reduction of benefits provided hereunder and/or other unfavorable changes to Employee.

(Signatures on following page)

IN WITNESS WHEREOF, the parties have executed this Agreement on the dates set forth below.

EQT CORPORATION

By:________________________________

____
Title

____
Date

EMPLOYEE

____
Name: Randall L. Crawford

____
Date

Exhibit 21

SUBSIDIARIES OF EQT CORPORATION
(as of December 31, 2015)

Pursuant to Item 601(b)(21) of Regulation S-K, we have omitted some subsidiaries that, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of December 31, 2014 under Rule 1-02(w) of Regulation S-X.

Entity	Jurisdiction
Allegheny Valley Connector, LLC	Delaware
Antrim Midstream, LLC	Delaware
EPC Investments, Inc.	Delaware
EQM Gathering, LLC	Delaware
EQM Gathering Holdings, LLC	Delaware
EQM Gathering Opco, LLC	Delaware
EQT Capital Corporation	Delaware
EQT CNG, LLC	Delaware
EQT Energy, LLC	Delaware
EQT Energy Supply, LLC	Delaware
EQT Energy Supply Holdings, LP	Delaware
EQT Gathering, LLC	Delaware
EQT Gathering Holdings, LLC	Delaware
EQT GP Corporation	Delaware
EQT GP Holdings, LP	Delaware
EQT GP Services, LLC	Delaware
EQT Investments Holdings, LLC	Delaware
EQT IP Ventures, LLC	Delaware
EQT Midstream Finance Corporation	Delaware
EQT Midstream Partners, LP	Delaware
EQT Midstream Services, LLC	Delaware
EQT Production Company	Pennsylvania
EQT Production Texas, LLC	Delaware
Equitrans Construction, LLC	Delaware
Equitrans Investments, LLC	Delaware
Equitrans Services, LLC	Delaware
Equitrans, L.P.	Pennsylvania
ET Blue Grass Clearing, LLC	Pennsylvania
ET Blue Grass, LLC	Delaware
MVP Holdco, LLC	Delaware
Rager Mountain Storage Company, LLC	Delaware

Exhibit 23.01

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

- Registration Statement (Form S-3 No. 333-158198) pertaining to the 2009 Dividend Reinvestment and Stock Purchase Plan,
- Registration Statement (Form S-3 No. 333-191781) pertaining to the registration of Debt Securities, Preferred Stock and Common Stock,
- Registration Statement (Form S-8 No. 333-185845) pertaining to the Employee Savings Plan,
- Registration Statement (Form S-8 No. 333-82193) pertaining to the 1999 Non-Employee Directors' Stock Incentive Plan,
- Registration Statement (Form S-8 No. 333-32410) pertaining to the Deferred Compensation Plan and the Directors' Deferred Compensation Plan,
- Registration Statement (Form S-8 No. 333-122382) pertaining to the 2005 Employee Deferred Compensation Plan and the 2005 Directors' Deferred Compensation Plan,
- Registration Statement (Form S-8 No. 333-152044) pertaining to the 2008 Employee Stock Purchase Plan,
- Registration Statement (Form S-8 No. 333-158682) pertaining to the 2009 Long-Term Incentive Plan, and
- Registration Statement (Form S-8 No. 333-195625) pertaining to the 2014 Long-Term Incentive Plan;

of our reports dated February 11, 2016, with respect to the consolidated financial statements and schedule of EQT Corporation and Subsidiaries and the effectiveness of internal control over financial reporting of EQT Corporation and Subsidiaries included in this Annual Report (Form 10-K) of EQT Corporation and Subsidiaries for the year ended December 31, 2015.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania
February 11, 2016

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.02

CONSENT OF INDEPENDENT PETROLEUM AND NATURAL GAS CONSULTANTS

As independent petroleum and natural gas consultants, we hereby consent to the inclusion of our audit report as an exhibit to and reference of our name in the Annual Report on Form 10-K for the year ended December 31, 2015 of EQT Corporation and to the incorporation of our audit report and our name by reference into EQT Corporation's effective registration statements under the Securities Act of 1933, as amended. We have no interest of a substantial or material nature in EQT Corporation or in any affiliate. We have not been employed on a contingent basis, and we are not connected with EQT Corporation, or any affiliate, as a promoter, underwriter, voting trustee, director, officer, employee or affiliate.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 11, 2016

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

Exhibit 31.01

CERTIFICATION

I, David L. Porges, certify that:

1. I have reviewed this Annual Report on Form 10-K of EQT Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditor and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 11, 2016

/s/ David L. Porges

David L. Porges
Chief Executive Officer

Exhibit 31.02

CERTIFICATION

I, Philip P. Conti, certify that:

1. I have reviewed this Annual Report on Form 10-K of EQT Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditor and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 11, 2016

/s/ Philip P. Conti

Philip P. Conti
Senior Vice President and Chief Financial Officer

Exhibit 32

CERTIFICATION

In connection with the Annual Report of EQT Corporation ("EQT") on Form 10-K for the period ended December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned certify pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of EQT.

/s/ David L. Porges February 11, 2016

David L. Porges
Chief Executive Officer

/s/ Philip P. Conti February 11, 2016

Philip P. Conti
Senior Vice President and Chief Financial Officer

Exhibit 99

EQT CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2015

\s\ Gabrielle Guerre

Gabrielle Guerre, P. E.
TBPE License No. 109935
Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

February 11, 2016

EQT Corporation
EQT Plaza
625 Liberty Avenue, Suite 1700
Pittsburgh, PA 15212-5861

Gentlemen:

At the request of EQT Corporation (EQT), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2015, prepared by EQT's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 22, 2016, and presented herein, was prepared for public disclosure by EQT in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent EQT's estimated net reserves attributable to the leasehold and royalty interests in certain properties owned by EQT as of December 31, 2015. The properties reviewed by Ryder Scott incorporate EQT reserve determinations and are located in the states of Kentucky, Ohio, Pennsylvania, Virginia, Texas, and West Virginia.

The properties covered by Ryder Scott's review account for 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves prepared by EQT as of December 31, 2015. However, not all properties were reviewed to the same level. Ryder Scott conducted a detailed, well by well, audit of the Company's largest properties, which consisted of 1,419 cases. This audit covered 81 percent of the Company's proved developed reserves. Ryder Scott's audit of the remaining 19 percent of the Company's proved developed properties consisted of an audit of aggregated groups not exceeding 200 wells per case for operated wells and 230 wells per case for non-operated wells, 75 cases in total (12,253 wells). For undeveloped locations, EQT determined, and Ryder Scott reviewed and approved, which areas within EQT's acreage were to be considered proven. Reserves were assigned and projected by EQT for locations within these proven areas and approved by Ryder Scott based on analogous type curves and offset production information.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities."

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Based on our review, including the data, technical processes and interpretations presented by EQT, it is our opinion that the overall procedures and methodologies utilized by EQT in preparing their estimates of the proved reserves as of December 31, 2015 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by EQT are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. EQT has informed us that in the preparation of their reserve and income projections, as of December 31, 2015, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by EQT attributable to EQT's interest in properties that we reviewed are summarized as follows:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold and Royalty Interests of
EQT Corporation

As of December 31, 2015

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Audited by Ryder Scott				
Net Reserves				
Gas – MMCF	5,217,258	435,732	3,457,318	9,110,308
Plant Products - MBarrels	93,591	4,937	39,954	138,482
Oil/Condensate - MBarrels	5,900	0	0	5,900

Liquid hydrocarbons are expressed in thousands of standard 42 gallon barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of shut-in and behind pipe categories.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At EQT’s request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves 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.” The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.”

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely than not to be achieved.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by EQT, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 98 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through November 2015, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by EQT and were considered sufficient for the purpose thereof. The remaining 2 percent of the proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

One hundred percent of the proved developed non-producing and undeveloped reserves that we reviewed were estimated primarily by the analogy method. The data utilized from the analogues were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by EQT relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by EQT for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2015 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. EQT has provided a detailed table (see Table 1) which summarizes the "benchmark prices" and "price reference" used by EQT for the various "take points" within Appalachia. In certain cases, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by EQT to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees, and/or distance from market, referred to herein as "differentials." The differentials used by EQT were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by EQT.

The table below summarizes EQT's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as EQT's "average realized prices." The average realized prices shown in the table below were determined from EQT's estimate of the total future gross revenue before production taxes for the properties reviewed by us and EQT's estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Average Realized Prices
North America		
United States, Appalachia and Texas regions	Gas	$0.985/MCF
	Plant Products	$6.16/Bbl
	Oil/Condensate	$41.18/Bbl

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in EQT's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserve estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by EQT are based on the operating expense reports of EQT. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. We have not conducted an independent verification of the data used by EQT. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by EQT are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by EQT were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by EQT. All development costs beyond 5 years are associated with the completion and fracturing of wells drilled within EQT's five year development plan. EQT's estimates of zero abandonment costs after salvage value for onshore properties were accepted without independent verification. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for EQT's estimate.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with EQT's plans to develop these reserves as of December 31, 2015. The implementation of EQT's development plans as presented to us is subject to the approval process adopted by EQT's management. As the result of our inquiries during the course of our review, EQT has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by EQT's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to EQT. Additionally, EQT has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2015, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by EQT were held constant throughout the life of the properties.

EQT's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by EQT to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by EQT. Wells or locations that are not currently producing may start producing earlier or later than anticipated in EQT's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

EQT's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which EQT owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by EQT for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of EQT are responsible for the preparation of reserve estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner.

We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

EQT has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of EQT's forecast of future proved production, we have relied upon data furnished by EQT with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by EQT. We consider the factual data furnished to us by EQT to be appropriate and sufficient for the purpose of our review of EQT's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by EQT and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by EQT, it is our opinion that the overall procedures and methodologies utilized by EQT in preparing their estimates of the proved reserves as of December 31, 2015 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by EQT are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to EQT. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by EQT.

EQT makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, EQT has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of EQT of the references to our name as well as to the references to our third party report for EQT, which appears in the December 31, 2015 annual report on Form 10-K of EQT. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by EQT.

We have provided EQT with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by EQT and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Gabrielle Guerre

Gabrielle Guerre, P.E.
TBPE License No. 109935
Vice President

[SEAL]

GG (DPR)/pl

TABLE 1

EQT 2015 YERR PRICING

	Brenton	Madison	Weston, Non Marcellus	Weston, Marcellus	KY West	Pikeville	BSG - NORA	BSG - RF	Carnegie	Equitrans	Utica	Permian	Royalty
INDEX (NYMEX + Basis)	2.228	1.505	1.394	1.421(PA) 1.428(WV)	2.449	2.506	2.430	2.491	1.428	1.428	1.394	2.473	1.701
SHRINK	14.04%	14.73%	5.54%	1.72%(PA) 1.50%(WV)	11.86%	11.78%	11.16%	11.16%	9.50%	9.50%	2.00%	6.00%	0.0%
BTU	1.090	1.163	1.242	1.043(PA) 1.094(WV)	1.149	1.220	1.033	1.033	1.166	1.203	1.054	1.005	1.000
G&C, $/mcf	0.610	0.570	0.062	0.584(PA) 0.764(WV)	0.582	0.549	0.723	0.788	0.788	0.734	0.525	0.517	0.000
NET GAS PRICE, $/mcf	**$1.477**	**$0.923**	**$1.573**	**$0.874(PA) $0.775(WV)**	**$1.897**	**$2.148**	**$1.507**	**$1.703**	**$0.803**	**$0.821**	**$0.914**	**$1.819**	**$1.701**

Source:

2015 Crude Oil Price based on first day of each month pricing for WTI, less area-specific Appalachian Basin Adjustment

2015 NGL price based on first day of each month pricing for Butane, ISO – Butane, Natural Gasoline, and Propane

	Brenton	Madison	Weston, Non Marcellus	Weston, Marcellus	KY West	Pikeville	BSG - NORA	BSG - RF	Carnegie	Equitrans	Utica	Permian	Royalty
NET CRUDE OIL, $/BBL	**43.271**	**43.271**	**43.271**	**30.638**	**45.256**	**45.256**	**44.530**	**44.530**	**43.271**	**43.271**	**45.259**	**47.282**	**-**
NET NGL PRICES, $/BBL				**3.937 (WV)**	**10.352**						**-0.598**	**9.669**	
Severance Tax Rates as % of revenue	6.14%	6.14%	6.14%	6.14% (WV)	4.40%	4.40%	2.68%	2.68%	6.14%	6.14%	0.58%	7.53%	0.00%
Property Tax Rates as % of revenue	1.34%	1.34%	1.34%	1.34% (WV)	1.69%	1.69%	6.64%	6.64%	1.34%	1.34%	3.27%	2.05%	0.00%
Sev & Property Tax Rates	7.48%	7.48%	0% PA 7.48% WV	0% PA 7.48% WV	6.09%	6.09%	9.32%	9.32%	0% PA 7.48% WV	0% PA 7.48% WV	3.85%	9.58%	0.00%

* The West Virginia state worker's compensation tax of $0.047/mcf is included in the severance tax percentages above.
* The Pennsylvania Impact Fee is included as a tax for all Pennsylvania horizontal Marcellus, Upper Devonian, and Utica wells.

	TCO	DTI	ETENN	M2	TGP Z4	TGP Z2	DEO	NFG	Waha	WTI (Cushing)	NYMEX
	$/Dth	$/Dth	$/Dth	$/Dth	$/Dth	$/Dth	$/Dth	$/Dth	$/Dth	$/Dth	$/Dth
Basis	-0.078	-1.190	-0.032	-1.155	-1.505	-0.154	-1.190	-1.190	-0.110	-	-
Index	**2.506**	**1.394**	**2.552**	**1.428**	**1.079**	**2.430**	**1.394**	**1.394**	**2.473**	**50.28**	**2.583**

Based on Gas Daily for TCO , DTI, TETCO (M2), and TGP for flow on the first day of each month in 2015.

Sales Point Percentages									
	TCO	DTI	ETENN	M2	DEO	TGP Z4	TGP Z2	NFG	WAHA
Kentucky West	25.0%	0.0%	0.0%	0.0%	0.0%	0.0%	75.0%	0.0%	0.0%
Pikeville	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Big Stone Gap - Nora	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%
Big Stone Gap - Roaring Fork	0.0%	0.0%	50.0%	0.0%	0.0%	0.0%	50.0%	0.0%	0.0%
Weston, Non Marcellus	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Weston, Marcellus - PA	0.8%	11.4%	0.0%	83.1%	0.0%	2.9%	0.0%	1.8%	0.0%
Weston, Marcellus - WV	0.1%	0.0%	0.0%	99.9%	0.0%	0.0%	0.0%	0.0%	0.0%
Permian	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Utica - OH	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Equitrans	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Carnegie	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Madison	10.0%	90.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brenton	75.0%	25.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Gabrielle Guerre was the primary technical person responsible for overseeing the estimate of the reserves prepared by Ryder Scott presented herein.

Mrs. Guerre, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2009, is a Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mrs. Guerre served in a number of reservoir engineering positions with ExxonMobil. For more information regarding Mrs. Guerre's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mrs. Guerre earned a Bachelor of Science degree in Mechanical Engineering from Kansas State University in 2005. She was given the department awards, Most Outstanding Engineer and Extraordinary Leadership & Service, upon completion of her degree. Mrs. Guerre is a registered Professional Engineer in the State of Texas. She is also a member of the Society of Petroleum Engineers, where she has served on the Gulf Coast Section Board of Directors for the past 4 years and is still an active Director.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mrs. Guerre fulfills. As part of her 2015 continuing education hours, Mrs. Guerre attended 1 hour of formalized training from various professional society presentations specifically relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mrs. Guerre attended an additional 10 hours of formalized in-house training as well as 6 hours of formalized external training during 2015 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on her educational background, professional training and more than 10 years of practical experience in the estimation and evaluation of petroleum reserves, Mrs. Guerre has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basincentered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

> *(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*
>
> *(B) The project has been approved for development by all necessary parties and entities, including governmental entities.*

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
1. *completion intervals which are open at the time of the estimate, but which have not started producing;*
2. *wells which were shut-in for market conditions or pipeline connections; or*
3. *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.