EQT Corp
Form 10-K
February 21, 2013

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, 2012

or

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

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, 2012: $8.0 billion

The number of shares of common stock outstanding
as of January 31, 2013: 150,347,211

DOCUMENTS INCORPORATED BY REFERENCE

The Company s definitive proxy statement relating to the annual meeting of shareholders (to be held April 17, 2013) will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2012 and is incorporated by reference in Part III to the extent described therein.

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Glossary of Commonly Used Terms, Abbreviations and Measurements

Commonly Used Terms

AFUDC Allowance for Funds Used During Construction carrying costs for the construction of certain long-term 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 comprised of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky and Virginia that lie in the Appalachian Mountains.

basis when referring to natural gas, 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.

cash flow hedge a derivative instrument that is used to reduce the exposure to variability in cash flows from the forecasted underlying transaction whereby the gains (losses) on the derivative are anticipated to offset the losses (gains) on the forecasted underlying transaction.

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.

farm tap natural gas supply service in which the customer is served directly from a well or a gathering pipeline.

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.

heating degree days measure used to assess weather s impact on natural gas usage calculated by adding the difference between 65 degrees Fahrenheit and the average temperature of each day in the period (if less than 65 degrees Fahrenheit). Each degree of temperature by which the average temperature falls below 65 degrees Fahrenheit represents one heating degree day. For example, a day with an average temperature of 50 degrees Fahrenheit will have 15 heating degree days.

Glossary of Commonly Used Terms, Abbreviations and Measurements

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.

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 futures contract to guarantee fulfillment of contract obligations.

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, ethane and iso-butane.

net net gas and oil wells or net acres are determined by summing 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 royalty interests (equal to 100% minus all royalties on a well or property).

proved reserves 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.

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, 1/6 or 1/4.

throughput total volumes of natural gas sold or transported by an entity.

transportation moving gas through pipelines on a contract basis for others.

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
IPO initial public offering
IRS Internal Revenue Service
KY PSC Kentucky Public Service Commission
NYMEX New York Mercantile Exchange
OTC over the counter
PA PUC Pennsylvania Public Utility Commission
SEC Securities and Exchange Commission
WV PSC West Virginia Public Service Commission

Measurements

Bbl = barrel
Btu = one British thermal unit
BBtu = billion British thermal units
Bcf = billion cubic feet
Bcfe = billion cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas
Dth = million British thermal units
Mcf = thousand cubic feet
Mcfe = thousand cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas
Mgal = thousand gallons
Mbbl = thousand barrels
MMBtu = million British thermal units
MMcf = million cubic feet
MMcfe = million cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas
Tcfe = trillion cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of 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, m forecast, approximate, expect, project, intend, plan, believe and other words of similar meaning in connection with any discussion of f operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this Annual Report include the matters discussed in the sections captioned Strategy in Business and Outlook in 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 the Company s strategy to develop its Marcellus and other reserves; drilling plans and programs (including the number, type, feet of pay and location of wells to be drilled, the conversion of drilling rigs to utilize natural gas and the availability of capital to complete these plans and programs); the expiration of leasehold terms before production can be established and the Company s ability to pool lease acreage; production and sales volumes and growth rates; gathering and transmission growth and volumes (including the subscription of additional capacity related to the expiration of Equitrans, LP firm transportation contracts); infrastructure programs (including the transmission and gathering expansion projects); technology (including drilling techniques); monetization transactions, including midstream asset sales (dropdowns) to EQT Midstream Partners, LP, the Company s publicly-traded master limited partnership formed in 2012 (the Partnership) and other asset sales, the proposed transfer of Equitable Gas Company, LLC (Equitable Gas) to PNG Companies LLC, joint ventures or other transactions involving the Company s assets); the timing of receipt of required approvals for the proposed Equitable Gas transaction; natural gas prices; reserves; capital expenditures, including funding sources and availability; financing requirements and availability; hedging strategy; the effects of government regulation and pending and future litigation; and tax position. The forward-looking statements 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, most of which are difficult to predict and many of which are beyond the Company s control. With respect to the proposed Equitable Gas transaction, these risks and uncertainties include, among others, the ability to obtain regulatory approvals for the transaction on the proposed terms and schedule; disruption to the Company s business, including customer, employee and supplier relationships resulting from the transaction; and risks that the conditions to closing may not be satisfied. 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 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 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 three business segments: EQT Production, EQT Midstream and Distribution. EQT Production is one of the largest natural gas producers in the Appalachian Basin with 6.0 Tcfe of proved natural gas and crude oil reserves across approximately 3.5 million gross acres, including approximately 540,000 gross acres in the Marcellus play, as of December 31, 2012. 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. The Distribution segment distributes and sells natural gas to residential, commercial and industrial customers through the Company s regulated distribution subsidiary, Equitable Gas Company, LLC (Equitable Gas). As a local distribution company, Equitable Gas has customers in southwestern Pennsylvania, West Virginia and eastern Kentucky. Equitable Gas also operates a small gathering system in Pennsylvania, and provides off-system sales activities that include the purchase and delivery of natural gas.

Key Events in 2012

In January 2012, EQT announced it would indefinitely suspend development of its Huron assets in favor of investing in its higher return Marcellus play. The decision was based on lower commodity pricing of natural gas, which resulted in a reduction in projected cash flow. A similar decision was made in December 2010, when the Company suspended the development of its CBM play in Virginia. The Company includes only proved developed reserves in these fields in its determination of proved reserves. The Company expects to continue to produce from existing wells in the Huron and CBM plays; however, contributions to the Company s total production sales volumes will gradually decline as the Company focuses the majority of its future drilling program in the Marcellus play. The Huron and CBM plays accounted for approximately 42% of production sales volumes in 2012 and are expected to account for approximately 27% of production sales volumes in 2013.

On February 13, 2012, EQT filed a registration statement with the SEC for an IPO of common units in a master limited partnership known as EQT Midstream Partners, LP (the Partnership). EQT pursued this strategy as a means of raising capital to further enhance and accelerate its economically attractive drilling and development programs, as well as to provide EQT Midstream with capital to continue pursuing additional opportunities. On July 2, 2012, the Partnership completed its underwritten IPO of 14,375,000 common units at $21.00 per unit (NYSE: EQM). EQT received net cash proceeds of approximately $231 million upon closing of the IPO, and retained a 57.4% limited partner interest and a 2% general partner interest in the Partnership. Prior to the IPO, the Company contributed to the Partnership 100% of Equitrans, LP (Equitrans), the Company s FERC-regulated transmission, storage and gathering subsidiary. An indirect wholly-owned subsidiary of EQT serves as the general partner of the Partnership and the Company continues to operate the Equitrans business pursuant to contractual arrangements signed in conjunction with the IPO. EQT records the non-controlling interest of the public limited partners in EQT s financial statements.

On December 19, 2012, EQT and its direct wholly-owned subsidiary, Distribution Holdco, LLC (Holdco), executed a Master Purchase Agreement with PNG Companies LLC (PNG Companies), the parent company of Peoples Natural Gas Company LLC (Peoples), to transfer 100% ownership of Equitable Gas and Equitable Homeworks, LLC (Homeworks) to PNG Companies. As part of the transfer, EQT will receive cash proceeds of $720 million, subject to adjustment, select midstream assets and commercial arrangements with PNG Companies and its affiliates. Homeworks and Equitable Gas are direct wholly-owned subsidiaries of Holdco. Peoples is a portfolio company of SteelRiver

Infrastructure Partners. The transaction is subject to various conditions, including receipt of the approval of the PA PUC, the WV PSC, the KY PSC and the FERC. The transaction is also subject to review under the Hart-Scott-Rodino Antitrust Improvement Act. The agreements provide that such approvals and review must be complete by December 19, 2013, subject to certain extension rights. These approvals and review may not be received or completed within the time allowed.

EQT Production Business Segment

EQT believes that it is a technology leader in extended lateral horizontal drilling in the Appalachian Basin and continues to improve its operations through the use of new drilling and completion technology which increases lateral length drilled and reserves per foot of pay. The Company s strategy is to maximize value by maintaining an industry leading cost structure and profitably developing its undeveloped Marcellus reserves. EQT s proved reserves increased by 12% in 2012, to a total of 6.0 Tcfe primarily across the Marcellus and Huron shale plays, and including CBM and other vertical wells. The Company s Marcellus assets contribute approximately 4.3 Tcfe in total proved reserves.

The following illustrations depict the southwestern portion of the Marcellus Shale formation (top left), while the larger map highlights EQT s acreage position within the Marcellus:

As of December 31, 2012, the Company s proved reserves are as follows:

(Bcfe)	Marcellus	Huron *	CBM	Total
Proved Developed	1,072	1,585	141	2,798
Proved Undeveloped	3,206			3,206
Total Proved Reserves	4,278	1,585	141	6,004

* Includes the Lower Huron, Cleveland, Berea sandstone and other Devonian age formations. Also included in the Huron play is 620 Bcfe of reserves from non-shale formations accessed through vertical wells.

The Company s natural gas wells are generally low-risk with long lives and low development and production costs. Assuming that future annual production from these reserves is consistent with 2012, the remaining reserve life of the Company s total proved reserves as calculated by dividing total proved reserves by 2012 produced volumes is 23 years.

The Company invested approximately $857 million on well development in 2012 and production sales volumes increased 33% compared to 2011. Capital spending for EQT Production is expected to be approximately $1.15 billion in 2013, the majority of which will be used to support the drilling of approximately 172 gross wells, including 153 Marcellus wells, 11 Upper Devonian wells and eight wells in the Utica Shale of Ohio. Production sales volumes are expected to be approximately 31% higher for 2013, with a range expected between 335 and 340 Bcfe, including 3,900 4,000 Mbbls of NGL production. Over the past three years, the Company s wells drilled and related capital expenditures for well development were:

	Years Ended December 31,		
Gross wells drilled:	**2012**	**2011**	**2010**
Horizontal Marcellus	127	105	90
Horizontal Huron	7	115	236
Horizontal Utica	1		
Total horizontal	135	220	326
Other		2	163
Total	135	222	489
Capital expenditures for well development: (in millions):			
Horizontal Marcellus	$ 810	$ 686	$ 436
Horizontal Huron	22	226	346
Horizontal Utica	4		
Total horizontal	836	912	782
Other	21	26	106
Total	$ 857	$ 938	$ 888

EQT Midstream Business Segment

During 2012, the Company completed various gathering line expansion projects and had a year-end gathering capacity of 1,115 MMcf per day, an increase of approximately 455 MMcf per day from 2011. With approximately 10,300 miles of gathering lines, EQT has Marcellus gathering capacity of 765 MMcf per day in Pennsylvania and 350 MMcf per day in West Virginia. To support the growth of production in the Marcellus play, EQT Midstream plans to add approximately 400 MMcf per day of incremental gathering capacity in 2013, all in Pennsylvania. See the map below (left) for a depiction of EQT s gathering lines, and compressor stations, in relationship to the overall Marcellus Shale formation.

The Company s transmission and storage system includes a FERC-regulated interstate pipeline system of approximately 700 miles that connects to five interstate pipelines and multiple distribution companies and is supported by 14 associated natural gas storage reservoirs with approximately 400 MMcf per day of peak delivery capability and 32 Bcf of working gas capacity. The map below (right) is a depiction of EQT s transmission lines, storage pools and compressor stations in relationship to the overall Marcellus Shale formation. Equitrans includes, among other things, the 2010 Marcellus Expansion Project completed in December 2010 and the Sunrise Pipeline which Equitrans operates under a lease from an EQT affiliate. EQT s storage reservoirs are clustered in two geographic areas connected to its Equitrans pipeline, with eight in northern West Virginia and six in southwestern Pennsylvania. During 2012, the Company completed construction of the Sunrise Pipeline, Blacksville compressor station and Braden Run interconnect projects resulting in 700 MMcf per day of increased transmission capacity. During 2013, EQT Midstream expects to add approximately 450 MMcf per day of incremental transmission capacity through the Morris III interconnect expansion and the Low Pressure East uprate projects for a total of 2,150 MMcf per day by the end of 2013.

In 2012, the Partnership was formed by EQT Corporation to own, operate, acquire and develop midstream assets in the Appalachian Basin. The Partnership provides midstream services to EQT and other third-party companies through its two primary assets: its transmission and storage system and its gathering system. The Partnership owns the approximately 700 mile FERC-regulated, interstate pipeline system, as well as approximately 2,000 miles of FERC-regulated, low-pressure gathering lines. EQT retained a 57.4% limited partner interest and a 2% general partner interest in the Partnership, whose results are consolidated in the Company s financial results.

EQT also has a gas marketing subsidiary, EQT Energy, LLC (EQT Energy), which provides optimization of capacity and storage assets, NGL sales and gas sales to commercial and industrial customers within its operational footprint through 4.9 Bcf of leased storage-related assets and approximately 1,100,000 Dth per day of third-party contractual pipeline capacity.

Strategy

EQT s strategy is to maximize shareholder value by maintaining an industry leading cost structure, profitably developing its undeveloped Marcellus reserves, and effectively and efficiently utilizing its extensive gathering and transmission assets that are uniquely positioned in the Marcellus Shale and in close proximity to the northeastern United States markets.

The Company continues to improve its use of technology by increasing lateral lengths, reducing cluster spacing and developing multi-well pads. EQT expects to continue increasing the average lateral lengths over time; however, lateral lengths will be limited by lease boundaries in the Marcellus play unless the Company is able to pool acreage with neighboring leaseholders. Because substantially all of the Company s acreage is held by production or in fee, 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 longer laterals and multi-well pads has the additional benefit of reducing the surface environmental footprint of the Company s drilling.

The Company believes the location of its midstream assets across a wide area of the Marcellus play in southwestern Pennsylvania and northern West Virginia is a competitive advantage which uniquely positions it for growth. In light of the growth of EQT Production and other producers in the Marcellus play, EQT Midstream intends to capitalize on the growing need for gathering and transmission infrastructure in the region, especially the need for midstream header connectivity to interstate pipelines in Pennsylvania and West Virginia. The 2013 gathering and transmission investments are expected to provide a platform for growth, mitigate curtailments and increase the flexibility and reliability of the Company s gathering and transmission systems.

In July 2012, the Company formed the Partnership, which is a growth-oriented master limited partnership designed to own, operate, acquire and develop midstream assets in the Appalachian Basin. Through pursuing accretive acquisitions from the Company, capitalizing on economically attractive organic growth opportunities and attracting additional third-party volumes, the Partnership is expected to provide an ongoing source of capital to the Company.

The Company is also helping to build additional demand for natural gas. With the assistance of a $700,000 grant received from the Pennsylvania Department of Environmental Protection, the Company opened a public-access natural gas fueling station in Pittsburgh, Pennsylvania during 2011. Investment break-even is expected during 2013 and plans are underway for an expansion of the station. In conjunction with this project, the Company is promoting the use of natural gas fleet vehicles, including its own. EQT plans to operate 14% of its vehicle fleet, more than 200 vehicles, on natural gas by the end of 2013. In addition, the Company converted two drilling rigs to utilize natural gas in 2012, with an additional two to three expected by the end of 2013.

See Capital Resources and Liquidity in Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K for details regarding the Company s capital expenditures.

Markets and Customers

No single customer accounted for more than 10% of revenues in 2012, 2011 or 2010.

Natural Gas Sales: EQT s produced natural gas is sold to marketers, utilities and industrial customers located mainly in the Appalachian area. Natural gas is a commodity and therefore the Company receives market-based pricing. The market price for natural gas can be volatile as demonstrated by significant declines in late 2011 and early 2012. Changes in the market price for natural gas impact the Company s revenues, earnings and liquidity. The Company is unable to predict potential future movements in the market price for natural gas and thus cannot predict the ultimate impact of prices on its operations; however, the Company monitors the market for natural gas and adjusts strategy and operations as deemed appropriate. 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. The Company s hedging strategy and information regarding its derivative instruments is set forth in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, and in Notes 1 and 4 to the Consolidated Financial Statements.

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. Until February 2011, when the Company sold its Langley natural gas processing complex (Langley), the Company processed 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 were recovered at Langley and transported to a fractionation plant owned by a third party for separation into commercial components. The third party marketed these components for a fee. The Company also had contractual processing arrangements whereby the Company sold gas to a third-party processor at a weighted average liquids component price. Subsequent to the closing of the sale of Langley to MarkWest Energy Partners, L.P. in February 2011, the processing of the Company s produced natural gas has been performed by a third-party vendor.

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

	2012	2011	2010
Average wellhead sales price per Mcfe sold (including hedges)	$ 4.26	$ 5.37	$ 5.62
Average wellhead sales price per Mcfe sold (excluding hedges)	$ 3.14	$ 4.85	$ 5.12

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 interconnects with Equitrans. Maintaining these interconnects provides the Company with access to geographically diverse markets.

Gathering system transportation volumes for 2012 totaled 335.4 BBtu, of which approximately 77% related to gathering for EQT Production, 13% related to third-party volumes and 10% related to volumes for other affiliates of the Company. Revenues from EQT Production and other affiliates accounted for approximately 88% of 2012 gathering revenues.

Natural Gas Transmission, Storage and Marketing: Services offered by EQT include commodity procurement, sales, delivery, risk management and other services. These operations are executed using Company owned and operated transmission and underground storage facilities as well as other contractual capacity arrangements with major pipeline and storage service providers in the eastern United States. EQT Energy uses leased storage capacity and firm transportation capacity to take advantage of price differentials and arbitrage opportunities when available. EQT Energy also engages in risk management and energy trading activities, the objective of which is to limit the Company s exposure to shifts in market prices and to optimize the use of the Company s assets.

Customers of EQT Midstream s gas transportation, storage, risk management and related services are affiliates and third parties in the northeastern United States, including, but not limited to, Dominion Resources, Inc., Keyspan Corporation, NiSource, Inc., PECO Energy Company and UGI Energy Services, Inc. EQT Energy s commodity procurement, sales, delivery, risk management and other services are offered to natural gas producers and energy consumers, including large industrial, utility, commercial and institutional end-users.

Equitrans firm transportation contracts expire between 2013 and 2023. The Company anticipates that the capacity associated with these expiring contracts will be remarketed or used by affiliates such that the capacity will remain fully subscribed. In 2012, approximately 84% of transportation volumes and 81% of revenues were from affiliates.

Natural Gas Distribution: The Company s Distribution segment provides natural gas distribution services to approximately 277,400 customers, consisting of 258,500 residential customers and 18,900 commercial and industrial customers in southwestern Pennsylvania, municipalities in northern West Virginia and field line sales, also referred to as farm tap service, in eastern Kentucky and West Virginia. Distribution s service areas have a rather static population and economy.

Equitable Gas purchases gas through contracts with various sources including major and independent producers in the Appalachian area and gas marketers (including an affiliate). The gas purchase contracts contain various pricing mechanisms, ranging from fixed prices to several different index-related prices. The cost of purchased gas is Equitable Gas largest operating expense and is passed through to customers utilizing mechanisms approved by the PA PUC, WV PSC and KY PSC. Equitable Gas is not permitted to profit from fluctuations in gas costs and does not purchase gas produced by EQT Production in order to maintain certain federal tax benefits for EQT.

Because most of its customers use natural gas for heating purposes, Equitable Gas revenues are seasonal, with approximately 67% of calendar year 2012 revenues occurring during the winter heating season (the months of January, February, March, November and December). Significant quantities of purchased natural gas are placed in underground storage inventory during the off-peak season to accommodate higher demand during the winter heating season.

Competition

Natural gas producers compete in the acquisition of properties, the search for and development of reserves, the production 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. Key competitors for new gathering systems include independent gas gatherers and integrated energy companies. EQT competes with numerous other companies offering the natural gas marketing services. Some of these competitors are affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. As a regulated utility, Equitable Gas distribution operation experiences only limited competition with other local distribution companies in its operating area, but experiences usage pressures as a result of alternative fuels and conservation.

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 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 taxes; and the gathering of production in certain circumstances. These regulations 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; 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. Both Kentucky and Virginia allow the statutory pooling or integration of tracts to facilitate development and exploration, while in West Virginia and Pennsylvania it is necessary to rely on voluntary pooling of lands and leases. In addition, state conservation and oil and gas laws generally limit the venting or flaring of natural gas.

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; 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. These regulations may affect the costs of or increase the time of developing new or expanded pipelines and compressor stations.

EQT Midstream has both non-regulated and regulated operations. The interstate natural gas transmission systems and storage operations are regulated by the FERC, and certain gathering lines are also subject to rate regulation by the FERC. For instance, the FERC approves tariffs that establish Equitrans rates, cost recovery mechanisms and other terms and conditions of service to Equitrans customers. The fees or rates established under Equitrans 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 and gathering also extends to: storage and related services; certification and construction of new facilities; extension or abandonment of 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.

EQT Production and EQT Midstream each engage in natural gas hedging activities, which include swaps and other derivatives that are regulated by, among others, the CFTC. In July 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) that, among other things, established federal oversight and regulation of swaps and certain entities that participate in swap markets. The Dodd-Frank Act authorized the CFTC to develop comprehensive regulation for types of swaps the Company may use. Among the most significant provisions of the Dodd-Frank Act are: mandatory clearing of swaps through regulated central clearing organizations and mandatory trading of such swaps on regulated exchanges or swap execution facilities (in each case, subject to certain key exceptions). The Dodd-Frank Act also required the registration and comprehensive oversight of swap dealers, which may act as swap counterparties to EQT Production and EQT Midstream.

In October 2012, joint rules of the CFTC and the SEC defining swap became effective and enabled the CFTC to begin implementing the new regulatory framework for swaps. As of the date of this report, the CFTC has adopted many final rules that will impose regulatory obligations on all market participants, including EQT Production and EQT Midstream. Compliance with many of these new rules will be phased in throughout 2013 and into at least 2014. The new rules may be directly applicable to EQT Production and EQT Midstream or may have an indirect effect where the rules apply to EQT Production and EQT Midstream s counterparties, which may include registered swap dealers. Other CFTC rules that may be relevant to EQT Production and EQT Midstream have yet to be finalized. Because many CFTC final rules do not have final compliance dates and other rules are still at the proposal stage, it is not possible at this time to predict the extent of the impact of the Dodd-Frank Act and new regulations on the Company s hedging program or regulatory compliance obligations. The Company anticipates, however, increased compliance costs and significant changes to current market practices as participants adapt to a new regulatory environment.

Equitable Gas distribution rates, terms of service and certain contracts with affiliates are subject to comprehensive regulation by the PA PUC and the WV PSC. The field line sales rates in Kentucky are subject to rate regulation by the KY PSC.

Equitable Gas must usually seek the approval of one or more of its regulators prior to changing its rates. Currently, Equitable Gas passes through to its regulated customers the cost of its purchased gas and transportation activities. Equitable Gas is provided an opportunity to recover a return in addition to the costs of its distribution and gathering delivery activities. However, Equitable Gas regulators do not guarantee recovery and may require that certain costs of operation be recovered over an extended term.

As required by Pennsylvania law, Equitable Gas has a customer assistance program that assists low-income customers with paying their gas bills. The cost of this program is recovered through rates charged to other residential customers.

Regulators periodically 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.

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; and the pollution, preservation, remediation or protection of human health and safety, natural resources, wildlife or 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. In most instances, the regulatory frameworks relate to the handling of drilling, production and processing materials and emissions, the disposal of drilling, production and processing wastes, the protection of water and air and the protection of people and aquatic life.

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, we conduct baseline and 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.

Climate Change

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. Effective January 1, 2011, the EPA began regulating greenhouse gas emissions by subjecting new facilities and major modifications to existing facilities that emit large amounts of greenhouse gases to the permitting requirements of the federal Clean Air Act. In addition, the U.S. Congress has been considering bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. 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 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 1,873 employees at the end of 2012. As of December 31, 2012, approximately 10% of the Company s workforce was subject to collective bargaining agreements. The collective bargaining agreement which covers approximately 8% of the Company s workforce will expire on July 8, 2015. The collective bargaining agreement which covers approximately 2% of the Company s workforce was extended in the fourth quarter of 2012 to January 22, 2016.

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. The Company s press releases and recent analyst presentations are also available on the Company s website.

Composition of Segment Operating Revenues

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

	For the year ended December 31,		
	2012	**2011**	**2010**
EQT Production:			
Natural gas sales	47%	41%	27%
EQT Midstream:			
Gathering revenue	17%	14%	13%
Distribution:			
Residential natural gas sales	12%	15%	20%

Financial Information about Segments

See Note 3 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.

Environmental

See Note 18 to the Consolidated Financial Statements for information regarding environmental matters.

Item 1A. Risk Factors

Risks Relating to Our Business

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 price volatility may have an adverse effect upon our revenue, profitability, future rate of growth and liquidity.

Our revenue, profitability, future rate of growth and liquidity depend upon the price for natural gas. The markets for natural gas are volatile and fluctuations in prices will affect our financial results. Natural gas prices are affected by a number of factors beyond our control, which include: weather conditions; the supply of and demand for natural gas; national and worldwide economic and political conditions; 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.

Lower natural gas prices may result in decreases in the revenue, margin and cash flow for each of our businesses, a reduction in drilling activity and the construction of new transportation capacity and downward adjustments to the value of oil and gas properties which may cause us to incur non-cash charges to earnings. Moreover, if we fail to control our operating costs during periods of lower natural gas prices, we could further reduce our margin. A reduction in margin or cash flow will reduce our funds available for capital expenditures and, correspondingly, our opportunities for growth. 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 prices may be accompanied by or result in increased well drilling costs, increased deferral of purchased gas costs for our distribution operations, increased production taxes, increased lease operating expenses, increased exposure to credit losses resulting from potential increases in uncollectible accounts receivable from our distribution customers, increased volatility in seasonal gas price spreads for our storage assets and increased customer conservation or conversion to alternative fuels. Significant price increases may subject us to margin calls on our commodity price derivative contracts (hedging arrangements, including futures contracts, 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 hedged transaction. 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 operations are subject to all of the inherent hazards and risks normally incidental to the production, transportation, storage and distribution of natural gas and NGLs, 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 security risks, including cyber security threats to gain unauthorized access to sensitive information or render data or systems unusable, and threats to the security of our or third parties facilities and infrastructure, such as processing plants 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 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 or maintain the necessary infrastructure to successfully deliver gas to market may adversely affect our earnings, cash flows and results of operations.

Our delivery of gas depends upon the availability, proximity and capacity of pipelines, other transportation facilities and gathering and processing facilities. In the Marcellus play, the capacity of transportation, gathering and processing facilities may be insufficient to accommodate potential production from existing and new wells. Competition for pipeline infrastructure within the region 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 is intended to address a lack of capacity on, and access to, existing gathering and transportation 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, gas price volatility, government approvals, title and property access problems, geology, compliance by third parties with their contractual obligations to us and other factors. We also deliver to and are served by third-party gas transportation, gathering, processing and storage facilities which 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 could result in adverse consequences to us, such as delays in producing and selling our natural gas. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those quoted on NYMEX or than we currently project. In addition, some of our third-party contracts may involve significant long-term financial commitments on our part. Moreover, our usage of third parties for transportation, 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 to market.

Also, our producing properties and operations are limited to 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 gas 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 growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our 2013 business plan, we considered allocating capital and other resources to various aspects of our businesses, including well development (primarily drilling), reserve acquisitions, exploratory activities, midstream infrastructure, distribution infrastructure, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2013 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 2013 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

On December 19, 2012, we signed an agreement to transfer Equitable Gas Company to PNG Companies in exchange for $720 million in cash, subject to adjustment, and select midstream assets and commercial arrangements. Acquisitions, dispositions and other strategic 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 acquisition or disposition of the assets. In addition, various factors including prevailing market conditions could negatively impact the benefits we receive from transactions. 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 results of operations.

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 systems, pipelines and distribution systems. 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, transportation, storage and distribution businesses are, in many cases, subject to state or federal regulation. The agencies that regulate our rates may prohibit us from realizing a level of return which we believe is appropriate. These restrictions may take the form of imputed revenue credits, cost disallowances (including purchased gas cost recoveries) and/or expense deferrals. Additionally, we may be required to provide additional assistance to low income residential customers to help pay their bills without the ability to recover some or all of the additional assistance in rates.

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. For instance, several initiatives aimed at greenhouse gas emissions and air pollution have recently been enacted or are being considered. On January 1, 2011, the EPA began regulating greenhouse gas emissions by subjecting new facilities and major modifications to existing facilities that emit large emissions of greenhouse gas emissions to the permitting requirements of the federal Clean Air Act.

Moreover, the U.S. Congress and various states have been evaluating climate-related legislation and other regulatory initiatives that would 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.

Additionally, on April 7, 2012, the EPA issued final rules that subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) programs. The EPA s rules also include NSPS standards for the completions of hydraulically fractured gas wells, applicable to newly drilled and fractured wells as well as existing wells that are refractured. The rules under NESHAP include maximum achievable control technology standards for certain equipment not currently subject to such standards. Compliance with these initiatives and rules could result in an increase to our costs or require changes that reduce our production.

Another area of potential 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 has been proposed or is under discussion at the federal and state levels. We cannot predict whether any such federal or state legislation or regulation will be enacted and, if enacted, how it may impact our operations, but enactment of additional laws or regulations could increase our operating costs.

Recent discussions regarding the federal budget have included proposals which 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 cash flows and profitability.

In July 2010, Congress enacted the Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) that, among other things, authorized the CFTC to develop comprehensive regulation for the swap markets. The Dodd-Frank Act created a new structure for trading OTC swaps, a market in which we are currently a market participant. Among other things, the Dodd-Frank Act established mandatory clearing of certain standardized swaps through regulated central clearing organizations and mandatory trade execution of those swaps on regulated exchanges or swap execution facilities (in each case, subject to certain key exceptions). The CFTC s new regulatory regime requires the registration and comprehensive oversight of swap dealers. The CFTC has finalized new rules directly applicable to EQT Production and EQT Midstream. In addition, the CFTC s finalized new rules may have an indirect effect on EQT Production and EQT Midstream s counterparties, which may include registered swap dealers. As of the date of this report, certain CFTC rules that may be relevant to EQT Production and EQT Midstream remain in the proposal stage. Furthermore, there is ongoing regulatory uncertainty regarding compliance dates for finalized CFTC rules. Throughout 2012 the CFTC repeatedly delayed compliance dates for numerous new rules. Other CFTC rules have also been challenged by industry groups in federal court, further adding to regulatory uncertainty.

We anticipate that the CFTC rules will increase regulatory compliance costs for EQT Production and EQT Midstream. Additionally, any counterparties of EQT Production or EQT Midstream that register as swap dealers will be required to comply with substantial and burdensome new regulatory obligations. Compliance costs incurred by these swap dealers may make it more expensive for entities that hedge, such as EQT Production and EQT Midstream, to hedge their risks with swaps. Accordingly, it is not possible at this time to predict the extent of the impact of the Dodd-Frank Act and new regulatory regime on our hedging program. It is possible, however, that the Dodd-Frank Act and regulatory regime for swaps will make hedging more expensive, uneconomic or unavailable, which could lead to increased costs or commodity price volatility or a combination of both.

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

We 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 flow from operations or other sources. Future challenges in the global financial system, including the capital markets, may adversely affect our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. 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 which could have a negative impact on our revenues and our credit ratings.

Any downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to raise capital through the issuance of debt or equity securities or other borrowing arrangements, which could adversely affect our business, results of operations and liquidity. We cannot be sure that our current ratings will remain in effect for any given period of time or that our rating will not be lowered or withdrawn entirely by a rating agency. An increase in the level of our indebtedness in the future may result in a downgrade in the ratings that are assigned to our debt. Any downgrade in our ratings could result in an increase in our borrowing costs, which would diminish financial results.

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 gas to market. Successfully identifying production opportunities involves a high degree of business experience, knowledge and careful evaluation of potential opportunities, along with subjective judgments and assumptions which may prove to be incorrect. In addition, any exploration projects increase the risks inherent in our natural gas activities. Specifically, seismic data is subject to interpretation and may not accurately identify the presence of natural gas or other hydrocarbons, which could adversely affect the results of our operations. 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.

The amount and timing of actual future gas 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 and a qualified work force, as well as weather conditions, gas price volatility, government approvals, title and property access problems, geology, equipment failure or accidents and other factors. Drilling for natural gas 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 operations.

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 lines and concerns raised by advocacy groups about hydraulic fracturing, 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.

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.

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 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 and oil reserves. In accordance with SEC requirements, we based the discounted future net cash flows from our proved reserves on the 12-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 and the amount, timing and cost of actual production. In addition, the 10% discount factor we use when calculating 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. These estimates and assumptions are inherently imprecise. 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 3.5 million gross acres (approximately 62% of which are considered undeveloped), which encompass substantially all of the Company s acreage of proved developed and undeveloped natural gas and oil production properties. Approximately 540,000 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, 2012, the Company estimated its total proved reserves to be 6,004 Bcfe, consisting of proved developed producing reserves of 2,735 Bcfe, proved developed non-producing reserves of 63 Bcfe and proved undeveloped reserves of 3,206 Bcfe. Substantially all of the Company s reserves reside in continuous accumulations.

The Company s estimate of proved natural gas and oil reserves are prepared by Company engineers. The engineer primarily responsible for preparing the reserve report and the technical aspects of the reserves audit received a bachelor s degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University and has 24 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 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. Ryder Scott reviewed 100% of the total net gas and liquid hydrocarbon proved reserves attributable to the Company s interests as of December 31, 2012. Ryder Scott conducted a detailed, well by well, audit of the Company s largest properties. This audit covered 80% of the Company s proved reserves. Ryder Scott s audit of the remaining 20% of the Company s properties consisted of an audit of aggregated groups not exceeding 200 wells per group. Ryder Scott s audit report has been filed herewith as Exhibit 99.01.

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 and crude oil reserves and future net cash flows is provided in Note 21 (unaudited) to the Consolidated Financial Statements.

In 2012, the Company commenced drilling operations (spud or drilled) on 127 gross horizontal wells with an aggregate of approximately 700,000 feet of pay in the Marcellus play. Total proved reserves in the Marcellus play increased 25% to 4.3 Tcfe in 2012 primarily as a result of the Company s 2012 drilling program. In the Huron play, the Company drilled 7 gross horizontal wells during 2012 with an aggregate of approximately 37,000 feet of pay. Total proved reserves in the Huron play (including vertical non-shale formations) decreased approximately 11% to 1.6 Tcfe, as the Company has indefinitely ceased development in the Huron play and plans to focus its capital expenditures during the next five years on developing the Marcellus play. The Company did not drill any gross CBM wells in 2012. The CBM play had total proved reserves of 0.1 Tcfe at December 31, 2012, slightly down from 2011. Natural gas production sales volumes in 2012 from the Marcellus, Huron and CBM plays were 150.5 Bcfe, 94.9 Bcfe and 13.1 Bcfe, respectively. Over the past three years, the Company has experienced a 99% developmental drilling success rate.

Natural gas, BTU premium, NGL and crude oil production and pricing:

[redacted]

For additional information on production and pricing, see   Consolidated Operational Data   in   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 and crude oil during 2012, 2011 and 2010 was $0.18, $0.20 and $0.24 per Mcfe, respectively. At December 31, 2012, the Company had approximately 51 multiple completion wells.

[redacted]

Summary of proved oil and gas reserves as of December 31, 2012 based on average fiscal year prices:

[redacted]

[redacted]

As of December 31, 2012, the Company did not have any reserves that have been classified as proved undeveloped reserves for more than five years.

Certain lease and acquisition agreements require the Company to drill a specific number of wells in 2013. A drilling obligation exists to drill 2 wells in the Lower Huron formation and approximately 20,000 gross undeveloped acres could expire if this obligation is not met. Within the Marcellus formation, the Company is required to drill 5 wells in 2013 and could incur the potential loss of approximately 14,000 gross undeveloped acres if this obligation is not met. The Company intends to satisfy such requirements either directly through its 2013 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, 2012, leases associated with approximately 20,000 gross undeveloped acres expire in 2013 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, however, has an active lease renewal program in areas targeted for development.

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

[redacted]

Selected data by state (at December 31, 2012 unless otherwise noted):

[redacted]

[redacted]

Capital expenditures at EQT Production totaled $991.8 million during 2012, including $134.6 million for the acquisition of undeveloped property. The Company invested approximately $607 million during 2012 converting undeveloped reserves to developed reserves and $250 million on wells still in progress at year end. During the year, the Company converted 159 Bcfe of proved undeveloped reserves to proved developed reserves. The Company had additions to proved developed reserves of 214 Bcfe, the majority of which were from wells drilled that had not previously been classified as proved. Downward revisions of 171 Bcfe in proved developed reserves were spread across all areas and all plays. New proved undeveloped reserves of 1,442 Bcfe were added during 2012. These reserve extensions and discoveries were mainly due to decreased lateral spacing in one of the Company s Greene County, Pennsylvania fields and additional proved locations in the Company s Wetzel and Doddridge County, West Virginia development areas. This increase was partially offset by negative revisions of 475 Bcfe. This reduction was primarily due to the decrease in the average NYMEX natural gas price for the year and caused certain existing proved undeveloped reserves to become uneconomical in accordance with SEC pricing requirements. As of December 31, 2012, the Company s proved undeveloped reserves totaled 3.2 Tcfe and all were associated with the development of the Marcellus play. All proved undeveloped drilling locations are expected to be drilled within five years.

Proved developed non-producing reserves decreased 401 Bcfe during 2012 as compared to 2011. During 2012, the Company incurred a higher percentage of its costs on the well completion phase compared to the drilling phase because of longer laterals, reduced cluster spacing and multi-well pads. As a result, the Company changed its methodology for classifying wells as proved developed non-producing reserves until only after the fracturing process has been completed.

The Company s 2012 extensions, discoveries and other additions resulting from extensions of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery of 1,656 Bcfe exceeded the 2012 production of 261 Bcfe.

Wells located in Kentucky are primarily in Huron formations with depths ranging from 2,500 feet to 6,000 feet. Wells located in West Virginia are primarily in Huron and Marcellus formations with depths ranging from 2,500 feet to 6,500 feet. Wells located in Virginia are primarily in CBM formations with depths ranging from 2,000 feet to 3,000 feet. Wells located in Pennsylvania are primarily in Marcellus formations with depths ranging from 5,000 feet to 8,000 feet.

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

EQT Midstream: EQT Midstream owns or operates approximately 10,300 miles of gathering lines and 244 compressor units with approximately 285,000 horsepower of installed capacity, as well as other general property and equipment.

	Kentucky	**West Virginia**	**Virginia**	**Pennsylvania**	**Total**
Approximate miles of gathering lines	3,550	4,200	1,700	850	10,300

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 700 mile FERC-regulated interstate pipeline system that connects to five interstate pipelines and multiple distribution companies. The system is supported by 14 associated natural gas storage reservoirs with approximately 400 MMcf per day of peak delivery capability and 32 Bcf of working gas capacity. The transmission and storage system stretches throughout north central West Virginia and southwestern Pennsylvania.

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

Distribution: This segment owns and operates natural gas distribution and gathering facilities as well as other general property and equipment in western Pennsylvania, West Virginia and Kentucky. The distribution operations consist of approximately 4,000 miles of pipe in Pennsylvania, West Virginia and Kentucky.

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

See Capital Resources and Liquidity in 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 and its subsidiaries. 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.

The Company has received a number of Notices of Violation (NOVs) from the Pennsylvania Department of Environmental Protection (PA DEP), which primarily allege violations of the Pennsylvania Oil and Gas Act, the Pennsylvania Solid Waste Management Act and/or the Pennsylvania Clean Streams Law, and the rules and regulations thereunder. The Company has responded to these NOVs and has generally 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 and Health Administration Data

Not Applicable.

Executive Officers of the Registrant (as of February 21, 2013)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Theresa Z. Bone (49)	Vice President and Corporate Controller (2007)	Elected to present position July 2007. Ms. Bone is also Vice President and Principal Accounting Officer of EQT Midstream Services, LLC, the general partner of the Partnership, the Company s publicly-traded master limited partnership, since January 2012.
Philip P. Conti (53)	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 EQT Midstream Services, LLC, the general partner of the Partnership, since January 2012.
Randall L. Crawford (50)	Senior Vice President and President, Midstream, Distribution and Commercial (2003)	Elected to present position April 2010; Senior Vice President and President, Midstream and Distribution from January 2008 to April 2010. Mr. Crawford is also Executive Vice President and a Director of EQT Midstream Services, LLC, the general partner of the Partnership, since January 2012.
Martin A. Fritz (48)	Vice President and President, Midstream Operations (2006)	Elected to present position April 2010; Vice President and President Midstream from January 2008 to April 2010.
Lewis B. Gardner (55)	General Counsel and Vice President, External Affairs (2008)	Elected to present position March 2008; Managing Director External Affairs and Labor Relations from January 2008 to March 2008. Mr. Gardner is also a Director of EQT Midstream Services, LLC, the general partner of the Partnership, since January 2012.
M. Elise Hyland (53)	Vice President and President, Commercial Operations (2008)	Elected to present position April 2010; Vice President and President, Equitable Gas from February 2008 to April 2010; President Equitable Gas from November 2007 to February 2008.
Charlene Petrelli (52)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007.
David L. Porges (55)	Chairman, President and Chief Executive Officer (1998)	Elected to present position May 2011; President, Chief Executive Officer and Director from April 2010 to May 2011; President, Chief Operating Officer and Director from February 2007 to April 2010. Mr. Porges is also Chairman, President and Chief Executive Officer of EQT Midstream Services, LLC, the general partner of the Partnership, since January 2012.
Steven T. Schlotterbeck (47)	Senior Vice President and President, Exploration and Production (2008)	Elected to present position April 2010; Vice President and President, Production from January 2008 to April 2010.

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 chosen and qualified.

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 2012 and 2011 are summarized as follows (in U.S. dollars per share):

	2012			2011		
	High	Low	Dividend	High	Low	Dividend
1st Quarter	$ 56.56	$ 46.04	$ 0.22	$ 49.99	$ 43.18	$ 0.22
2nd Quarter	55.20	43.69	0.22	54.25	45.68	0.22
3rd Quarter	59.46	52.20	0.22	65.97	47.86	0.22
4th Quarter	62.74	56.45	0.22	73.10	49.54	0.22

As of January 31, 2013, there were 3,056 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, result of operations and financial conditions, strategic direction and other factors. During the period reported above, the Company paid a dividend at an annual rate of $0.88 per share. In December 2012, concurrent with the announcement of entering into a definitive agreement to transfer Equitable Gas to PNG Companies, the Company announced a new annual dividend rate, effective January 2013, of $0.12 per share which the Company believes better reflects the blend of the Company s core businesses remaining after giving effect to the pending transaction a dividend supporting midstream business and a capital-intensive, rapidly growing production business. The Board of Directors has the discretion to change this new annual dividend rate at any time for the reasons described above.

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 have occurred in the three months ended December 31, 2012:

Period	Total number of shares (or units) purchased (a)	Average price paid per share (or unit)	Total number of shares (or units) purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 2012 (October 1 October 31)				
November 2012 (November 1 November 30)	274.00	$ 59.87		
December 2012 (December 1 December 31)	1.00	$ 60.20		

Total	275.00	$	59.87

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

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 25 companies (the Self-Constructed Peer Group), whose individual companies are listed in footnote (a) below. An investment of $100 (with reinvestment of all dividends) is assumed to have been made at the close of business on December 31, 2007 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, 2012.

	12/07	12/08	12/09	12/10	12/11	12/12
EQT Corporation	**100.00**	**64.12**	**85.87**	**89.61**	**111.27**	**121.76**
S&P 500	**100.00**	**63.00**	**79.67**	**91.67**	**93.61**	**108.59**
Self-Constructed Peer Group	**100.00**	**58.74**	**90.68**	**99.17**	**104.45**	**109.98**

(a) The Self-Constructed Peer Group includes 25 companies, which are: Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., CONSOL Energy Inc., Energen Corporation, EOG Resources, Inc., EXCO Resources, Inc., MarkWest Energy Partners, L.P., MDU Resources Group, Inc., National Fuel Gas Company, NSTAR, ONEOK, Inc., Penn Virginia Corporation, Pioneer Natural Resources Company, Plains Exploration & Production Company, Questar Corporation, Quicksilver Resources Inc., Range Resources Corporation, Sempra Energy, SM Energy Company, Southwestern Energy Company, Spectra Energy Corp, Ultra Petroleum Corp., Whiting Petroleum Corporation and The Williams Companies, Inc. NSTAR was acquired during 2012 and is included in the calculation from December 31, 2007 through December 31, 2011, at which time it was removed from the peer group calculation.

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,				
	2012	2011	2010	2009	2008
	(Thousands, except per share amounts)				
Operating revenues	$ 1,641,608	$ 1,639,934	$ 1,374,395	$ 1,311,356	$ 1,609,384
Net income attributable to EQT Corporation	$ 183,395	$ 479,769	$ 227,700	$ 156,929	$ 255,604
Earnings per share:					
Basic	$ 1.23	$ 3.21	$ 1.58	$ 1.20	$ 2.01
Diluted	$ 1.22	$ 3.19	$ 1.57	$ 1.19	$ 2.00
Total assets	$ 8,849,862	$ 8,772,719	$ 7,098,438	$ 5,957,257	$ 5,329,662
Long-term debt	$ 2,526,173	$ 2,746,942	$ 1,949,200	$ 1,949,200	$ 1,249,200
Cash dividends declared per share of common stock	$ 0.88	$ 0.88	$ 0.88	$ 0.88	$ 0.88

See Item 1A, Risk Factors and Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Notes 2, 3, 6 and 7 to the Consolidated Financial Statements for a discussion of an adjustment to operating revenues for all periods and other 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 Operations

In 2012, EQT highlights included the following:

- Record annual production sales volumes of 258.5 Bcfe, 33% higher than 2011
- Record Marcellus sales volumes of 150.6 Bcfe, 85% higher than 2011
- Record gathered volumes of 335.4 TBtu, 30% higher than 2011
- Increased proved reserves by 12% to 6.0 Tcfe
- Completed the Partnership s IPO
- Announced an agreement to sell Equitable Gas

Net income attributable to EQT Corporation for 2012 was $183.4 million, $1.22 per diluted share, compared with $479.8 million, $3.19 per diluted share, in 2011. In 2011, the Company recorded $202.9 million of pre-tax gains on dispositions related to the sales of the Big Sandy Pipeline (Big Sandy) and Langley. The Company was negatively impacted in 2012 by lower realized sales prices for production sales volumes, higher depreciation, depletion and amortization (DD&A) and higher interest expense partially offset by increases in both production and gathered volumes and lower income tax expense.

Operating income was $470.5 million in 2012 compared to $861.3 million in 2011, a decrease of $390.8 million. In addition to the $202.9 million gain in 2011 on the dispositions of Big Sandy and Langley, the decrease from 2011 was a result of approximately 25% lower realized sales prices for production sales volumes, a 23% higher production depletion rate and higher other operating expenses, partially offset by a 33% increase in production volumes, a 30% increase in gathering volumes and higher transmission revenues.

Production sales volumes increased primarily as a result of increased production from the 2011 and 2012 drilling programs in the Marcellus play acreage. This increase was partially offset by the normal production decline in the Company s producing wells. The average wellhead sales price to EQT Corporation including the effect of the Company s hedging program was $4.26 per Mcfe in 2012 compared to $5.37 per Mcfe in 2011. Hedging activities resulted in an increase in the average natural gas sales price of $1.19 per Mcf in 2012 and $0.55 per Mcf in 2011. Gathering net operating revenues increased due to a 30% increase in gathered volumes, partially offset by a 7% decrease in the average gathering fee. The gathered volume increase was driven by higher volumes gathered for EQT Production in the Marcellus play.

Operating expenses for 2012 were $1,171.1 million compared to $981.5 million in 2011, an increase of $189.6 million. This increase was primarily attributable to higher DD&A charges from higher production volumes at a production depletion rate of $1.54/Mcfe compared to $1.25/Mcfe in 2011 and higher production-related and selling, general and administrative (SG&A) costs consistent with the growth in produced volumes and midstream throughput.

On July 2, 2012, the Partnership, a subsidiary of the Company, completed its IPO of 14,375,000 common units representing limited partner interests in the Partnership, which represented 40.6% of the Partnership s outstanding equity. The Company retained a 59.4% equity interest in the Partnership, including 2,964,718 common units, 17,339,718 subordinated units and a 2% general partner interest. The Company continues to consolidate the results of the Partnership. EQT records the noncontrolling interest of the public limited partners in EQT s financial statements.

EQT s consolidated net income for 2011 was $479.8 million, $3.19 per diluted share, compared with $227.7 million, $1.57 per diluted share, for 2010. In 2011, the Company recorded $128.3 million of after-tax gains on dispositions related to the sales of Langley and Big Sandy.

Operating income increased to $861.3 million in 2011 from $470.5 million in 2010. In addition to the $202.9 million gain on the dispositions of Big Sandy and Langley and the absence of revenues and expenses associated with these assets, operating income was favorably impacted by increased production sales volumes and higher gathering and transmission revenues which more than offset the increase in operating expenses associated with higher volumes, lower storage and marketing net operating revenues and a lower average wellhead sales price to EQT Corporation.

Production sales volumes increased more than 44% in 2011 from 2010, largely associated with the Marcellus play, as a result of increased production from the 2010 and 2011 drilling programs partially offset by the normal production decline in the Company s producing wells. Gathered revenues increased as a result of a 32% increase in gathered volumes primarily related to the Company s production growth. Transmission net revenues increased as a result of higher firm transportation activity and capacity from the Equitrans 2010 Marcellus expansion project. The average wellhead sales price to EQT Corporation including the effect of the Company s hedging program was $5.37 per Mcfe in 2011 compared to $5.62 per Mcfe in 2010. Hedging activities resulted in an increase in the average natural gas sales price of $0.55 per Mcf in both 2011 and 2010.

Operating expenses for 2011 increased $77.6 million compared to 2010 primarily as a result of increased production depletion and expenses on higher produced volumes as well as higher selling, general and administrative expenses consistent with the growth of the business. These increases were partially offset by the absence of expenses associated with Big Sandy and Langley, primarily operating and maintenance expenses, and favorable adjustments for certain non-income tax matters.

See Other Income Statement Items for a discussion of other income, interest expense and income taxes and Investing Activities in Capital Resources and Liquidity for a discussion of capital expenditures.

Consolidated Operational Data

EQT Production s average wellhead sales price is calculated by allocating some of its revenues to EQT Midstream for the gathering and transportation of produced gas. The following operational information presents detailed gross liquid and natural gas operational information as well as midstream deductions to assist the understanding of the Company s consolidated operations.

in thousands (unless noted)	2012	Years Ended December 31, 2011	2010
LIQUIDS			
NGLs:			
Sales Volume (MMcfe)	13,052	11,579	10,454
Sales Volume (Mbbls)	3,484	3,076	2,712
Gross Price ($/Mbbls)	$ 44.75	$ 60.42	$ 48.76
Gross NGL Revenue	$ 155,926	$ 185,845	$ 132,244
BTU Premium (Ethane sold as natural gas):			
Sales Volume (MMbtu)	22,494	16,124	11,404
Price ($/MMbtu)	$ 2.83	$ 4.04	$ 4.35
BTU Premium Revenue	$ 63,668	$ 65,168	$ 49,622
Oil:			
Sales Volume (MMcfe)	1,587	1,248	718
Sales Volume (Mbbls)	264	208	120
Net Price ($/Mbbls)	$ 83.95	$ 81.58	$ 70.42
Net Oil Revenue	$ 22,161	$ 16,968	$ 8,428
Total Liquids Revenue	$ 241,755	$ 267,981	$ 190,294
GAS			
Sales Volume (MMcf)	243,886	181,566	123,442
NYMEX Price ($/Mcf) (a)	$ 2.83	$ 4.04	$ 4.35
Gas Revenues	$ 690,293	$ 733,814	$ 537,150
Basis	(960)	24,047	17,527
Gross Gas Revenue (unhedged)	$ 689,333	$ 757,861	$ 554,677
Total Gross Gas & Liquids Revenue (unhedged)	$ 931,088	$ 1,025,842	$ 744,972
Hedge impact	290,557	101,047	67,449
Total Gross Gas & Liquid Revenue	$ 1,221,645	$ 1,126,889	$ 812,421
Total Sales Volume (MMcfe)	258,525	194,393	134,614
Average hedge adjusted price ($/Mcfe)	$ 4.72	$ 5.80	$ 6.04
Midstream Revenue Deductions ($ / Mcfe)			
Gathering to EQT Midstream	$ (1.02)	$ (1.11)	$ (1.32)
Transmission to EQT Midstream	(0.19)	(0.22)	(0.37)
Third-party gathering and transmission*	(0.36)	(0.31)	(0.42)
Third-party processing	(0.10)	(0.12)	-
Total midstream revenue deductions	(1.67)	(1.76)	(2.11)
Average wellhead sales price to EQT Production	$ 3.05	$ 4.04	$ 3.93
EQT Revenue ($ / Mcfe)			
Revenues to EQT Midstream	$ 1.21	$ 1.33	$ 1.69
Revenues to EQT Production	3.05	4.04	3.93
Average wellhead sales price to EQT Corporation	$ 4.26	$ 5.37	$ 5.62

(a) The Company s annual volume weighted NYMEX price (average NYMEX natural gas price ($/Mcf) was $2.79, $4.04 and $4.39 in the years ended December 31, 2012, 2011 and 2010, respectively).

* Due to the sale of unused capacity on the El Paso 300 line that was not under long-term resale agreements at prices below the capacity charge, third-party gathering and transmission rates increased by $0.04 per Mcfe for the year ended 2012. In 2011, the unused capacity on the El Paso 300 line not under long-term resale agreements was sold at prices above the capacity charge,

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decreasing third-party gathering and transmission rates by $0.03 per Mcfe for the year ended 2011. The El Paso 300 line came online in 2011 and thus, there was no unused capacity sold in the year ended 2010.

Business Segment Results

Business segment operating results 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. Differences between budget and actual headquarters expenses totaling $23.3 million, $29.3 million and $15.1 million were not allocated to the operating segments for the years ended December 31, 2012, 2011 and 2010, respectively. As part of the 2012 budgeting process, the Company allocated additional corporate overhead charges to the operating segments.

The Company has reported the components of each segment s operating income and various operational measures in the sections below, and where appropriate, has provided information describing how a measure was derived. EQT s management believes that presentation of this information provides useful information to management and investors regarding the financial condition, operations and trends of each of EQT s business segments without being obscured by the financial condition, operations and trends for the other segments or by the effects of corporate allocations of interest, income taxes and other income. In addition, management uses these measures for budget planning purposes. The Company s management reviews and reports the EQT Production segment results for operating revenues and purchased gas costs with transportation costs reflected as a deduction from operating revenues as management believes this presentation provides a more useful view of net wellhead price and is consistent with industry practices. Third-party transportation costs are reported as a component of purchased gas costs in the consolidated results. The Company has reconciled each segment s operating income to the Company s consolidated operating income and net income in Note 3 to the Consolidated Financial Statements.

EQT Production

Results of Operations

	Years Ended December 31,				
	2012	2011	% change 2012 - 2011	2010	% change 2011 - 2010
OPERATIONAL DATA					
Natural gas, NGL and crude oil production (MMcfe) (a)	260,963	198,821	31.3	139,021	43.0
Company usage, line loss (MMcfe)	(2,438)	(4,428)	(44.9)	(4,407)	0.5
Total production sales volumes (MMcfe)	258,525	194,393	33.0	134,614	44.4
Average daily sales volumes (MMcfe/d)	706	533	32.5	369	44.4
Sales volume detail (MMcfe):					
Horizontal Marcellus Play	150,552	81,602	84.5	25,474	220.3
Horizontal Huron Play	36,934	40,081	(7.9)	38,816	3.3
CBM Play	13,084	13,682	(4.4)	13,493	1.4
Other (vertical non-CBM)	57,955	59,028	(1.8)	56,831	3.9
Total production sales volumes	258,525	194,393	33.0	134,614	44.4
Average wellhead sales price to EQT Production ($/Mcfe)	$ 3.05	$ 4.04	(24.5)	$ 3.93	2.8
Lease operating expenses, excluding production taxes (LOE) ($/Mcfe)	$ 0.18	$ 0.20	(10.0)	$ 0.24	(16.7)
Production taxes ($/Mcfe) (b)	$ 0.16	$ 0.20	(20.0)	$ 0.24	(16.7)
Production depletion ($/Mcfe)	$ 1.54	$ 1.25	23.2	$ 1.26	(0.8)
Depreciation, depletion and amortization (DD&A) (thousands):					
Production depletion	$ 401,456	$ 248,286	61.7	$ 175,629	41.4
Other DD&A	8,172	8,858	(7.7)	8,070	9.8
Total DD&A (thousands)	$ 409,628	$ 257,144	59.3	$ 183,699	40.0
Capital expenditures (thousands) (c)	$ 991,775	$ 1,087,840	(8.8)	$ 1,245,914	(12.7)

		Years Ended December 31,			
FINANCIAL DATA (thousands)	2012	2011	% change 2012 - 2011	2010	% change 2011 - 2010
Total net operating revenues	$ 793,773	$ 791,285	0.3	$ 537,657	47.2
Operating expenses:					
LOE, excluding production taxes	46,212	40,369	14.5	33,784	19.5
Production taxes (b)	49,943	40,542	23.2	33,630	20.6
Exploration expense	10,370	4,932	110.3	5,368	(8.1)
Selling, general and administrative (SG&A)	89,707	61,200	46.6	57,689	6.1
DD&A	409,628	257,144	59.3	183,699	40.0
Total operating expenses	605,860	404,187	49.9	314,170	28.7
Operating income	$ 187,913	$ 387,098	(51.5)	$ 223,487	73.2

(a) Natural gas, NGL and oil production represents the Company s interest in natural gas, NGL and oil production measured at the wellhead. It is equal to the sum of total sales volumes and Company usage and line loss.

(b) Production taxes include severance and production-related ad valorem and other property taxes. In 2012, production taxes also include the Pennsylvania impact fee of $15.3 million. The production taxes unit rate for 2012 excludes the impact of $6.7 million paid upon enactment in that year for pre-2012 Marcellus wells.

(c) Capital expenditures in the EQT Production segment include $92.6 million of liabilities assumed in exchange for producing properties as part of the ANPI transaction in 2011 and $230.7 million of undeveloped property which was acquired with EQT common stock in 2010.

Year Ended December 31, 2012 vs. December 31, 2011

EQT Production s operating income totaled $187.9 million for 2012 compared to $387.1 million for 2011. The $199.2 million decrease in operating income was primarily due to a lower average wellhead sales price and an increase in operating expenses partially offset by increased sales of produced natural gas and NGLs.

Total operating revenues were $793.8 million for 2012 compared to $791.3 million for 2011. The $2.5 million increase in operating revenues was primarily due to a 33% increase in production sales volumes which offset a 25% decrease in the average wellhead sales price to EQT Production. The increase in production sales volumes was primarily the result of increased production from the 2011 and 2012 drilling programs in the Marcellus play, as well as the acquisition of producing properties associated with the ANPI transaction in May 2011 which added 2.6 Bcfe of sales volumes in 2012. This increase was partially offset by the normal production decline in the Company s producing wells. The $0.99 per Mcfe decrease in the average wellhead sales price to EQT Production was primarily due to a 31% decrease in the average NYMEX gas price as well as lower basis and NGL prices, partially offset by higher hedging gains and lower affiliated gathering rates compared to 2011. The average wellhead sales price was also impacted unfavorably in 2012 by $0.03 per Mcfe as a result of an $8.2 million adjustment to recognize financial instrument put premiums which should have been recorded ratably over 2010 and 2011 and by $0.04 per Mcfe for the cost of transmission capacity on the El Paso 300 line, including long-term resale agreements. Management evaluated the size and nature of the put premium adjustment and concluded that the adjustment was not material to the financial statements.

Operating expenses totaled $605.9 million for 2012 compared to $404.2 million for 2011. The increase in operating expenses was the result of increases in DD&A, SG&A, production taxes, LOE and exploration expense.

Depletion expense increased as a result of a higher overall depletion rate and higher produced volumes in 2012. The increase in the depletion rate was primarily due to an increase in costs to complete wells, higher capitalized overhead and interest costs and the removal of proved reserves due to lower natural gas prices and the suspension of drilling activity in the Huron play. The increase in SG&A was primarily a result of higher corporate overhead and commercial services allocations of $22.0 million, increased labor and relocation expenses of $4.0 million associated with increased Marcellus drilling and an increase in franchise taxes of $1.9 million.

In February 2012, the Commonwealth of Pennsylvania passed legislation imposing a natural gas impact fee. The legislation, which covers a significant portion of EQT s Marcellus Shale acreage, imposes an annual fee for a period of fifteen years on each well drilled in Pennsylvania. The impact fee adjusts annually based on three factors: age of the well, changes in the Consumer Price Index and the average monthly NYMEX gas price. Production taxes increased primarily due to the Pennsylvania impact fee in 2012 of $15.3 million, of which $6.7 million represents the retroactive fee for pre-2012 Marcellus wells, as well as an increase in property taxes partially offset by a decrease in severance taxes due to the decrease in average wellhead sales price in 2012.

The increase in LOE was mainly a result of increased Marcellus activity in 2012 primarily related to a $3.0 million increase in salt water disposal expenses and a $2.1 million increase in labor expenses, as well as the elimination of $2.3 million of third-party operating expense reimbursements, as part of the ANPI transaction. Exploration expense increased in 2012 primarily due to increased impairments of unproved lease acreage of $3.0 million and also an increase in geophysical activity in 2012 related to the Ohio Utica formation.

Year Ended December 31, 2011 vs. December 31, 2010

EQT Production s operating income totaled $387.1 million for 2011 compared to $223.5 million for 2010, an increase of $163.6 million between years, primarily due to increased production sales volumes and higher wellhead sales prices to EQT Production, partially offset by an increase in DD&A and other operating costs resulting from higher volumes.

Total net operating revenues were $791.3 million for 2011 compared to $537.7 million for 2010. The $253.6 million increase in operating revenues was primarily due to a 44% increase in production sales volumes as well as a 3% increase in the average wellhead sales price to EQT Production. The increase in sales volumes was the result of increased production from the 2010 and 2011 drilling programs, primarily in the Marcellus play, as well as the acquisition of producing properties associated with acquiring the Class A interest in a trust thereby acquiring 100% of the net profits interest associated with the producing properties (the ANPI transaction), as described in Note 7 to the Consolidated Financial Statements in May 2011 which added 5.5 Bcfe of sales volumes in 2011. This increase was partially offset by the normal production decline in the Company s producing wells. The $0.11 per Mcfe increase in the average wellhead sales price to EQT Production was primarily due to lower gathering rates and higher sales prices for NGLs and oil in 2011 partially offset by an 8% decrease in the average NYMEX price compared to 2010. The average wellhead sales price was also impacted favorably from selling excess transmission capacity on the Tennessee Gas Pipeline 300-Line in the fourth quarter of 2011.

Operating expenses totaled $404.2 million for 2011 compared to $314.2 million for 2010. The 29% increase in operating expenses was primarily the result of increased DD&A, production taxes and LOE. The depletion expense increased as a result of higher volumes in 2011 partially offset by a slightly lower overall depletion rate. Production taxes increased due to higher revenues and increased assessments in certain jurisdictions that impose these taxes in the year of production. The increase in LOE was primarily the result of increased activity in 2011 as well as the elimination, as part of the ANPI transaction, of certain operating expense reimbursement agreements. Lower costs for road and location maintenance due to less severe weather in 2011 partly offset these increases. SG&A increased due to higher overhead and commercial services costs associated with the growth of the company and higher franchise tax expense. These increases were partially mitigated by a charge in 2010 related to the buy-out of excess contractual capacity for water treatment and lower professional services, hiring and relocation costs in 2011.

EQT Midstream

Results of Operations

		Years Ended December 31,			
	2012	2011	% change 2012 - 2011	2010	% change 2011 2010
OPERATIONAL DATA					
Gathered volumes (BBtu)	335,407	258,179	29.9	195,642	32.0
Average gathering fee ($/MMBtu)	$ 0.90	$ 0.97	(7.2)	$ 1.11	(12.6)
Gathering and compression expense ($/MMBtu) (a)	$ 0.24	$ 0.30	(20.0)	$ 0.37	(18.9)
Transmission pipeline throughput (BBtu)	221,944	159,384	39.3	109,165	46.0
Net operating revenues (thousands):					
Gathering	$ 302,255	$ 249,607	21.1	$ 212,170	17.6
Transmission	104,501	90,405	15.6	84,190	7.4
Storage, marketing and other	42,693	64,614	(33.9)	100,097	(35.4)
Total net operating revenues	$ 449,449	$ 404,626	11.1	$ 396,457	2.1
Unrealized losses on derivatives and inventory (thousands) (b)	$ 9,225	$ 755	1,121.9	$ 379	99.2
Capital expenditures (thousands)	$ 375,731	$ 242,886	54.7	$ 193,128	25.8
FINANCIAL DATA (thousands)					
Total operating revenues	$ 505,498	$ 525,345	(3.8)	$ 580,698	(9.5)
Purchased gas costs	56,049	120,719	(53.6)	184,241	(34.5)
Total net operating revenues	449,449	404,626	11.1	396,457	2.1
Operating expenses:					
Operating and maintenance (O&M)	97,400	83,907	16.1	107,601	(22.0)
SG&A	49,943	49,901	0.1	48,127	3.7
DD&A	64,782	57,135	13.4	61,863	(7.6)
Total operating expenses	212,125	190,943	11.1	217,591	(12.2)
Gain on dispositions		202,928	(100.0)		100.0
Operating income	$ 237,324	$ 416,611	(43.0)	$ 178,866	132.9

(a) Gathering and compression expense for the full year 2011 excludes $7.1 million of favorable adjustments for certain non-income tax reserves.

(b) Included in storage, marketing and other net operating revenues.

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Year Ended December 31, 2012 vs. December 31, 2011

EQT Midstream s operating income totaled $237.3 million for 2012 compared to $416.6 million for 2011. The decrease in operating income was primarily the result of the $202.9 million pre-tax gain on the sales of Langley and Big Sandy in 2011 and increased operating expenses in 2012 partly offset by an increase in 2012 net operating revenues.

Total net operating revenues were $449.4 million for 2012 compared to $404.6 million for 2011. The increase in total net operating revenues was due to a $52.6 million increase in gathering net operating revenues and a $14.1 million increase in transmission net operating revenues, partly offset by a $21.9 million decrease in storage, marketing and other net operating revenues.

Gathering net operating revenues increased due to a 30% increase in gathered volumes, partly offset by a 7% decrease in the average gathering fee. The gathered volume increase was driven by higher volumes gathered for EQT Production in the Marcellus play. The average gathering fee decreased due to the mix of gathered volumes as Marcellus volumes increased while Huron and other volumes, which have a higher gathering fee, decreased.

Transmission net operating revenues in 2012 increased from the prior year primarily as a result of $15.8 million of increased capacity reservation revenues resulting from the Sunrise Pipeline project and the Equitrans 2010 Marcellus expansion project and higher firm transportation activity from affiliated shippers due to increased Marcellus volumes. These revenues were negatively impacted year over year by the absence of $16.0 million of revenues recorded on Big Sandy in the first half of 2011.

Storage, marketing and other net operating revenues decreased from the prior year primarily as a result of unrealized losses on derivatives and inventory, lower margins and activity due to lower price spreads and volatility, and a $4.3 million decrease in net operating revenue from NGLs marketed for non-affiliated producers primarily as a result of lower liquids pricing.

Total operating revenues decreased $19.8 million primarily as a result of lower sales prices on decreased commercial activity and a lower gathering rate partly offset by an increase in gathered volumes and increased transmission revenue. Total purchased gas costs decreased $64.7 million primarily as a result of lower commodity prices on decreased commercial activity.

Operating expenses totaled $212.1 million for 2012 compared to $190.9 million for 2011. The increase in O&M was primarily the result of a $13.3 million decrease in non-income taxes largely as a result of favorable property tax settlements recorded in 2011 combined with increases in 2012 in line with the growth of the business. In addition, personnel cost increases in 2012 were partly offset by the absence of $2.8 million in operating costs for Langley and Big Sandy in 2011. SG&A was flat year over year as the EQT Midstream segment recovered approximately $2.9 million from the Lehman Brothers bankruptcy, reversed $2.5 million in reserves for the recovery of a long-term, volume-based regulatory asset and allocated $5.2 million more in expenses to affiliates, offsetting increases in personnel costs and $1.2 million of increased expenses related to the Partnership s IPO and subsequent operation as a public company. DD&A increased as a result of higher assets placed in service.

Year Ended December 31, 2011 vs. December 31, 2010

EQT Midstream s operating income totaled $416.6 million for 2011, including gains on the dispositions of Langley and Big Sandy of $202.9 million, compared to $178.9 million for 2010. In addition to the gains, operating income increased as a result of increased gathering and transmission volumes combined with lower operating expenses. These favorable variances were partially offset by decreased storage, marketing and other net operating revenues and a lower average gathering fee.

Total net operating revenues were $404.6 million for 2011 compared to $396.5 million for 2010. The increase in total net operating revenues was due to a $37.4 million increase in gathering net operating revenues and a $6.2 million increase in transmission net operating revenues, partly offset by a $35.5 million decrease in storage, marketing and other net operating revenues.

Gathering net operating revenues increased due to a 32% increase in gathered volumes, partially offset by a 13% decrease in the average gathering fee. This increase in gathered volumes was driven primarily by higher produced natural gas volumes gathered for EQT Production in the Marcellus play. The decrease in the average gathering fee was a result of lower gathering rates charged to affiliates and other shippers in the Marcellus play.

Transmission net operating revenues increased in 2011 as a result of higher firm transportation activity from affiliated shippers due to the increased Marcellus volumes and increased capacity from the Equitrans 2010 Marcellus expansion project, partly offset by the absence of revenues from the sale of Big Sandy.

Storage, marketing and other net operating revenue decreased from the prior year primarily as a result of a decrease in natural gas volumes marketed for third parties utilizing pipeline capacity, lower net revenue from NGLs marketed for non-affiliated producers, lower margins due to reduced commodity prices and lower price spreads and volatility. Higher NGL prices were more than offset by the loss of processing fees associated with the sale of Langley.

Total operating revenues decreased in 2011 by $55.4 million primarily as a result of lower sales prices on decreased commercial activity and a lower gathering rate partially offset by an increase in gathered volumes and increased transmission revenue. Total purchased gas costs decreased as a result of decreased commercial activity.

Operating expenses totaled $190.9 million for 2011 compared to $217.6 million for 2010. The decrease in operating expenses was primarily due to decreases of $23.7 million in O&M and $4.7 million in DD&A. The decrease in O&M was primarily due to the absence of operating expenses associated with Langley and Big Sandy and reductions in certain non-income property tax reserves partly offset by increased compensation costs. The decrease in DD&A was primarily due to the sales of Big Sandy and Langley, partly offset by increased depreciation on increased investment in gathering and compression infrastructure.

Distribution

Results of Operations

	Years Ended December 31,				
	2012	2011	% change 2012 - 2011	2010	% change 2011 2010
OPERATIONAL DATA					
Heating degree days (30-year average = 5,710)	4,693	5,189	(9.6)	5,516	(5.9)
Residential sales and transportation volume (MMcf)	19,326	22,333	(13.5)	23,132	(3.5)
Commercial and industrial volume (MMcf)	27,651	28,752	(3.8)	27,124	6.0
Total throughput (MMcf)	46,977	51,085	(8.0)	50,256	1.6
Net operating revenues (thousands):					
Residential	$ 105,382	$ 115,912	(9.1)	$ 117,418	(1.3)
Commercial and industrial	45,084	48,968	(7.9)	48,614	0.7
Off-system and energy services	19,557	22,672	(13.7)	21,365	6.1
Total net operating revenues	$ 170,023	$ 187,552	(9.3)	$ 187,397	0.1
Capital expenditures (thousands)	$ 28,745	$ 31,313	(8.2)	$ 36,619	(14.5)
FINANCIAL DATA (thousands)					
Total operating revenues	$ 313,990	$ 419,678	(25.2)	$ 474,143	(11.5)
Purchased gas costs	143,967	232,126	(38.0)	286,746	(19.0)
Net operating revenues	170,023	187,552	(9.3)	187,397	0.1
Operating expenses:					
O&M	42,838	43,383	(1.3)	44,047	(1.5)
SG&A	34,117	31,524	8.2	35,994	(12.4)
DD&A	24,454	25,747	(5.0)	24,174	6.5
Total operating expenses	101,409	100,654	0.8	104,215	(3.4)
Operating income	$ 68,614	$ 86,898	(21.0)	$ 83,182	4.5

Year Ended December 31, 2012 vs. December 31, 2011

Distribution s operating income totaled $68.6 million for 2012 compared to $86.9 million for 2011. The decrease in operating income was primarily due to record warm weather during 2012.

Net operating revenues were $170.0 million for 2012 compared to $187.6 million for 2011. Net operating revenues from residential customers decreased $10.5 million as a result of weather and related customer usage patterns. Weather was 10% warmer in 2012 as compared to 2011 and 18% warmer than the 30-year National Oceanic and Atmospheric Administration (NOAA) average for the Company s service territory. According to NOAA, it was the warmest twelve-month calendar period on record in the Company s service territory. Commercial and industrial net operating revenues also decreased by $3.9 million primarily due to warmer weather and related customer usage patterns of $3.0 million and lower revenue associated with competitive contract renewals in 2012. Off-system and energy services net operating revenues decreased $3.1 million primarily due to a $2.4 million favorable change in estimated recoverable costs in 2011 and $2.0 million in fewer asset optimization opportunities realized during 2012 as compared to 2011. These declines were partially offset by higher revenues from gathering activities resulting from increased rates.

Decreases in total operating revenues and purchased gas costs were primarily due to lower customer throughput as a result of warmer weather during 2012, a decrease in the commodity component of tariff rates and a decrease in asset optimization off-system and energy services revenues.

Operating expenses totaled $101.4 million for 2012 compared to $100.7 million for 2011, as a $2.6 million increase in SG&A expenses was partly offset by a decrease in DD&A and O&M expenses. The increase in SG&A expenses was primarily due to a $3.0 million reduction of certain non-income tax reserves in 2011 as a result of settlements with tax authorities partly offset by lower bad debt expense of $0.9 million, which was primarily the result of a lower commodity component of residential tariff rates in 2012 and the Company s favorable collections experience. The Company will continue to closely monitor its collection rates and adjust its reserve for uncollectible accounts as necessary. The decrease in DD&A was primarily due to a change in the assumptions used in valuing the segment s asset retirement obligation.

Year Ended December 31, 2011 vs. December 31, 2010

Distribution s operating income totaled $86.9 million for 2011 compared to $83.2 million for 2010. The increase in operating income was primarily the result of an increase in estimated recoverable costs in 2011, an increase in the Company s West Virginia base rates and lower operating expenses. These increases were partly offset by warmer weather in 2011.

Net operating revenues were $187.6 million for 2011 compared to $187.4 million for 2010 as an increase in estimated recoverable costs in 2011 was substantially offset by a decrease in residential net operating revenues. Net operating revenues from residential customers decreased $1.5 million as a result of warmer weather partially offset by the full year impact of the Company s West Virginia base rate increase, which was approved in August 2010. The weather in Distribution s service territory in 2011 was 6% warmer than 2010 and 9% warmer than the territory s 30-year NOAA average. Commercial and industrial net operating revenues increased $0.4 million primarily as a result of an increase in usage by one industrial customer. The high volume sales to this industrial customer had low unit margins and did not ratably impact total net operating revenues. Off-system and energy services net operating revenues were higher as a result of a change in estimated recoverable costs in 2011 offset by fewer asset optimization opportunities realized in 2011. A decrease in the commodity component of residential tariff rates and fewer asset optimization transactions resulted in a decrease in both total operating revenues and purchased gas costs.

Operating expenses totaled $100.7 million for 2011 compared to $104.2 million for 2010. The decrease in operating expenses was primarily the result of lower bad debt expense and the reduction of certain non-income tax reserves resulting from settlements with tax authorities. These decreases were partially offset by an increase in other compensation related costs and depreciation expense in 2011. The decrease in bad debt expense was primarily the result of a decrease in the commodity component of residential tariff rates and the Company s favorable collections experience.

Other Income Statement Items

Other Income

	Years Ended December 31,		
	2012	**2011**	**2010**
		(Thousands)	
Other income	$ 15,965	$ 34,138	$ 12,898

Other income includes equity in earnings of nonconsolidated investments, primarily the Company s investments in Nora Gathering, LLC of $6.1 million, $7.2 million and $9.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Other income for the year ended December 31, 2012 also included $6.9 million of AFUDC compared to $4.0 million in 2011, a $2.9 million increase as a result of further construction on the Equitrans Sunrise Pipeline project, which was placed into service during 2012.

Other income increased in 2011 compared to 2010 as a result of the $10.1 million pre-tax gain on the ANPI transaction, an $8.5 million gain on sales of available-for-sale securities and an increase in the equity portion of AFUDC as a result of construction on the Equitrans Sunrise Pipeline project.

Other income for the year ended December 31, 2010 also included a $2.1 million gain on sales of available-for-sale securities.

Interest Expense

	Years Ended December 31,		
	2012	**2011**	**2010**
		(Thousands)	
Interest expense	$ 184,786	$ 136,328	$ 128,157

Interest expense increased $48.5 million from 2011 to 2012 as a result of additional expense from the Company s November 2011 issuance of $750 million 4.875% notes due in 2021 and a $23.3 million payment to close a forward-starting interest rate swap settled in 2012. This increase was partially offset by higher capitalized interest on increased Marcellus well development and midstream pipeline construction in 2012.

During the third quarter of 2011, the Company entered into an interest rate hedge in anticipation of refinancing $200 million of long-term debt scheduled to mature in November 2012. Given the Company s strong liquidity position, the Company retired the debt using cash on hand and recognized a $23.3 million expense in the year ended December 31, 2012 to close the interest rate hedge.

Interest expense increased by $8.2 million from 2010 to 2011 as a result of the Company s increased debt to fund its continued investment in drilling and midstream infrastructure during the year. The increase in interest from the Company s November 2011 issuance of $750 million 4.875% notes and the debt assumed in the May 2011 ANPI transaction was partially offset by higher capitalized interest on increased Marcellus well development. The Company also paid higher commitment fees under the terms of its $1.5 billion revolving credit facility entered into on December 8, 2010 than under the previous facility.

Weighted average annual interest rates on the Company s long-term debt were 6.4%, 6.8% and 6.8% for 2012, 2011 and 2010, respectively. Weighted average annual interest rates on the Company s short-term debt were 1.8% and 0.7% for 2011 and 2010, respectively. The Company had no short-term debt in 2012.

Income Taxes

	Years Ended December 31,		
	2012	**2011**	**2010**
		(Thousands)	
Income taxes	$ 105,296	$ 279,360	$ 127,520

Income tax expense decreased by $174.1 million from 2011 to 2012 as a result of lower pre-tax income and a decrease in the Company s effective income tax rate from 36.8% to 34.9%. The decrease in the rate from 2011 to 2012 was primarily due to a reduction in pre-tax book income on state tax paying entities and the impact of the Partnership s IPO. The effective tax rate is impacted by the recent IPO which modified the Midstream ownership structure and now reflects Partnership earnings for which the noncontrolling public limited partners are directly responsible for the related income taxes. The Company consolidates the pre-tax income related to the noncontrolling public limited partners share of partnership earnings but excludes the related tax provision. Other rate reconciling items had a larger percentage impact on the effective tax rate in 2012 than 2011 due to significantly higher pre-tax income in 2011.

Income tax expense increased by $151.8 million from 2010 to 2011 as a result of higher pre-tax income and an increase in the Company s effective income tax rate from 35.9% to 36.8%. The Company s regulated business accounts for tax deductible repair costs as a permanent difference, as the related deferred taxes are recoverable in rates. The increase in the effective tax rate in 2011 was primarily the result of the tax benefit for these repair costs being higher in 2010 than in 2011. State income taxes were also higher in 2011 due to a shift in the Company s non-regulated business to states with higher income tax rates. Other rate reconciling items had a larger percentage impact on the effective tax rate in 2010 than 2011 due to significantly higher pre-tax income in 2011.

The Company was in an overall federal tax net operating loss (NOL) position for 2012, 2011 and 2010. For federal income tax purposes, the Company deducts approximately 83% of drilling costs as intangible drilling costs (IDC) in the year incurred. The primary reasons for the Company s net operating loss positions are the IDC deduction resulting from the Company s drilling program and the accelerated tax deprecation for expansion of gathering infrastructure which provide tax deductions in excess of book deductions. IDCs, however, are sometimes limited for purposes of the alternative minimum tax (AMT) and can result in the Company paying AMT even when generating a regular tax NOL. See Note 8 to the Consolidated Financial Statements for further discussion of the Company s income taxes.

Net Income Attributable to Noncontrolling Interests

As a result of the Partnership s IPO in 2012, net income attributable to noncontrolling interests was $13.0 million for the year ended December 31, 2012.

Outlook

The Company is committed to profitably developing its Marcellus reserves through environmentally responsible, cost-effective and technologically advanced horizontal drilling. The market price for natural gas can be volatile, as demonstrated by significant declines in late 2011 and early 2012, and these fluctuations can impact the Company s revenues, earnings and liquidity. The Company is unable to predict future movements in the market price for natural gas and thus cannot predict the ultimate impact of prices on its operations; however, the Company monitors the market for natural gas and adjusts its strategy and operations appropriately.

Capital spending for well development (primarily drilling) in 2013 is expected to be approximately $1.15 billion to support the drilling of approximately 172 gross wells, including 153 Marcellus wells, 11 Upper Devonian wells and eight wells in the Utica Shale of Ohio. Sales volumes are expected to be between 335 and 340 Bcfe for an anticipated production sales volume growth of approximately 31% in 2013.

In addition, the Company plans to spend $400 million on midstream infrastructure in 2013 to support its production growth and expects gathering and transmission volumes to increase as a result of this expansion. EQT Midstream expects to add approximately 400 MMcf per day of incremental gathering capacity and approximately 450 MMcf per day of transmission capacity in 2013. The 2013 capital spending plan is expected to be funded by cash on hand, cash flow generated from operations and proceeds from expected midstream asset sales (dropdowns) to the Partnership.

On December 19, 2012, the Company and its direct wholly-owned subsidiary Holdco executed the Master Purchase Agreement with PNG Companies, pursuant to which EQT and Holdco will transfer 100% of their ownership interests of Equitable Gas and Homeworks to PNG Companies in exchange for cash and select midstream assets of, and new commercial arrangements with, PNG Companies and its affiliates. Homeworks and Equitable Gas are direct wholly-owned subsidiaries of Holdco. Peoples is a portfolio company of SteelRiver Infrastructure Partners. The transaction (or portions thereof) requires the approval of the PA PUC, the WV PSC, the KY PSC and the FERC. In addition, the transaction is subject to review under the Hart-Scott-Rodino Act. The agreements provide that such approvals and review must be complete by December 19, 2013, subject to certain extension rights. These approvals and review may not be received or completed within the time allowed.

We continue to focus on achieving our objective of maximizing shareholder value via an overarching strategy of economically accelerating the monetization of our asset base and prudent pursuit of investment opportunities, all while maintaining a strong balance sheet with solid cash flow. While the tactics continue to evolve based on market conditions, the Company is considering arrangements, including asset sales to the Partnership or others and joint ventures, to monetize the value of mature assets for the re-deployment into higher-growth Marcellus Shale development.

Capital Resources and Liquidity

The Company s primary sources of cash for 2012 were cash flows from operating activities and a cash distribution from the Partnership in connection with the Partnership s issuance of common units in the IPO. The Company s primary use of cash in 2012 was for capital expenditures and repayments of long-term debt.

Operating Activities

The Company s net cash provided by operating activities decreased $94.4 million from $915.3 million in 2011 to $820.9 million in 2012. The decline in operating receipts was a result of several factors, including a 25% decline in average wellhead sales prices of natural gas, higher cash payments for interest of $58.4 million, a decrease in dividends received from Nora Gathering, LLC of $10.8 million, record warm weather and higher operating expenses. This decrease was partially offset by a 33% increase in the production of natural gas, a 30% increase in gathered volumes and a $19.6 million decrease in cash payments for income taxes.

The Company s net cash provided by operating activities during 2011 was $915.3 million compared to $789.7 million for the same period of 2010. The increase in cash flows provided by operating activities was primarily attributable to higher operating receipts as a result of increased production in 2011, which more than offset the negative cash flow impact of paying $47.2 million in taxes in 2011 compared to receiving tax refunds of $129.5 million in 2010.

Investing Activities

Cash flows used in investing activities totaled $1,394.5 million for 2012 as compared to $624.3 million for 2011. The $770.2 million increase in cash flows used was attributable to reduced proceeds received from the sale of assets in 2012 compared to the $620 million proceeds received for the sales of Langley and Big Sandy and $29.9 million received for the sales of available-for-sale securities, all in 2011. Additionally, as described below, the Company increased capital expenditures by $125.1 million from 2011 to 2012.

Cash flows used in investing activities totaled $624.3 million for 2011 as compared to $1,239.4 million for 2010. The decrease in cash flows used in investing activities was primarily attributable to 2011 proceeds from the sales of Big Sandy, Langley and available-for-sale securities. Capital expenditures increased $27.3 million to $1,274.3 million in 2011. See the discussion of capital expenditures below.

Capital Expenditures

	2013 Forecast		2012 Actual		2011 Actual		2010 Actual	
Well development (primarily drilling)	$	1,150 million	$	857 million	$	938 million	$	888 million

Property acquisitions*		$ 135 million	$ 150 million	$ 358 million
Midstream infrastructure	$ 400 million	$ 376 million	$ 243 million	$ 193 million
Distribution infrastructure and other corporate items	$ 45 million	$ 31 million	$ 36 million	$ 39 million
Total	$ 1,595 million	$ 1,399 million	$ 1,367 million	$ 1,478 million
Less: non-cash			$ 93 million	$ 231 million
Total cash capital expenditures	$ 1,595 million	$ 1,399 million	$ 1,274 million	$ 1,247 million

* The Company does not forecast property acquisitions within its capital spending plan.

Capital expenditures for drilling and development totaled $857 million and $938 million during 2012 and 2011, respectively. The Company drilled 135 gross wells (129 net wells) in 2012, including 127 horizontal Marcellus wells with approximately 700,000 feet of pay, 7 horizontal Huron wells with approximately 37,000 feet of pay and 1 horizontal Utica well with approximately 5,000 feet of pay, compared to 222 gross wells (213 net wells) in 2011, including 105 horizontal Marcellus wells with approximately 500,000 feet of pay and 115 horizontal Huron wells with approximately 550,000 feet of pay. The $81 million decrease in capital expenditures for well development was primarily due to the suspension of drilling wells in the Huron play in 2012. This was partially offset by additional development of the Marcellus play at a lower average cost per well in 2012 when compared to 2011 as a result of drilling efficiencies and lower service company costs. Capital expenditures for 2012 also included approximately $135 million for undeveloped property acquisitions, including $78 million within the Utica play and $57 million within the Marcellus play.

Capital expenditures for the midstream operations totaled $376 million for 2012. During the year, EQT Midstream turned in-line approximately 89 miles of pipeline and 36,000 horse power of compression primarily in the Marcellus play. EQT Midstream also added 455 MMcfe per day of incremental gathering capacity and 700 MMcfe per day of transmission capacity in 2012. During 2011, midstream capital expenditures were $243 million. EQT Midstream turned in-line 46 miles of pipeline and 20,000 horse power of compression primarily within the Marcellus play in 2011.

Capital expenditures at Distribution totaled $29 million and $31 million during 2012 and 2011, respectively, principally for pipeline replacement.

Capital expenditures for drilling and development totaled $938 million and $888 million during 2011 and 2010, respectively. The Company drilled 222 gross wells (213 net wells) in 2011, including 105 horizontal Marcellus wells with approximately 500,000 feet of pay and 115 horizontal Huron wells with approximately 550,000 feet of pay, compared to 489 gross wells (395 net wells) in 2010, including 90 horizontal Marcellus wells with approximately 300,000 feet of pay and 236 horizontal Huron wells with approximately 1.0 million feet of pay. Capital expenditures for 2011 also included $57 million for undeveloped property acquisitions, primarily within the Marcellus play and $93 million of liabilities assumed in exchange for producing properties in the ANPI transaction. Capital expenditures for 2010 included $358 million for undeveloped property acquisitions, $231 million of which was non-cash.

Capital expenditures for the midstream operations totaled $243 million for 2011. During the year, EQT Midstream turned in-line 46 miles of pipeline and 20,000 horse power of compression primarily in the Marcellus play. During 2010, midstream capital expenditures were $193 million. EQT Midstream turned in-line 132 miles of pipeline and 21,000 horse power of compression primarily within the Huron play in 2010.

Capital expenditures at Distribution totaled $31 million and $37 million during 2011 and 2010, respectively, principally for pipeline replacement.

Financing Activities

Cash flows used in financing activities totaled $75.5 million for 2012 as compared to cash flows provided by financing activities of $540.3 million in 2011. In 2012, the Company received $276.8 million in connection with the Partnership s issuance of common units, repaid maturing long-term debt of $219.3 million and paid the initial distribution to the Partnership s noncontrolling interests of $5.0 million. In 2011, the Company issued $750 million of 4.875% Senior Notes due November 15, 2021 and repaid short-term loans of $53.7 million.

Cash flows provided by financing activities totaled $540.3 million for 2011 as compared to $449.7 million for 2010. During 2011, the Company issued $750 million of 4.875% Senior Notes due November 15, 2021. The proceeds of these notes are to be used for general corporate purposes. The Company also repaid short-term loans of $53.7 million. In 2010, the Company received $537.2 million from a common stock offering.

In December 2012, in connection with its announcement of its definitive agreement to transfer Equitable Gas to PNG Companies, the Company announced its intent to reduce its annual dividend rate, effective January 2013, to $0.12 per share, which the Company believes better reflects the blend of the Company s core businesses remaining after giving effect to the pending transaction a dividend supporting midstream business and a capital-intensive, rapidly growing production business. The Company expects the favorable impact on cash provided by financing activities of the decline in the dividend rate to be partly offset by distributions to noncontrolling interests of the Partnership.

Short-term Borrowings

EQT primarily utilizes short-term borrowings to fund capital expenditures in excess of cash flow from operating activities until they can be permanently financed, to ensure sufficient levels of inventory and to fund required margin deposits on derivative commodity instruments. The amount of short-term borrowings used for inventory transactions is driven by the seasonal nature of the Company s natural gas distribution and marketing operations. Margin deposit requirements vary based on natural gas commodity prices, our credit ratings and the amount and type of derivative commodity instruments.

The Company has a $1.5 billion revolving credit facility that expires on December 8, 2016. The Company may request two one-year extensions of the expiration date 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 16 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 rating. Fixed period Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on the Company s then current credit rating.

The Company had no loans or letters of credit outstanding under its revolving credit facility as of December 31, 2012 and 2011. For the years ended December 31, 2012 and 2011, the Company incurred commitment fees averaging approximately 25 basis points and 30 basis points, respectively, to maintain credit availability under the revolving credit facility.

There were no short-term loans outstanding at any time during 2012. The maximum amount of outstanding short-term loans at any time during the year ended December 31, 2011 was $104.0 million. The average daily balance of short-term loans outstanding during the year ended December 31, 2011 was approximately $5.5 million at a weighted average annual interest rate of 1.81%.

The Company s short-term borrowings generally have original maturities of three months or less.

In connection with the IPO, the Partnership entered into a $350 million revolving credit facility that expires on July 2, 2017. 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 13 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Partnership. The Company is not a guarantor of the Partnership s obligations under the credit facility.

The Partnership s obligations under the revolving portion of the credit facility are unsecured.

The Partnership, which was formed in 2012, had no letters of credit and no loans outstanding under the revolving credit facility at any time during the year ended December 31, 2012. For the year ended December 31, 2012, the Partnership incurred commitment fees averaging approximately 25 basis points to maintain credit availability under the revolving credit facility.

Security Ratings and Financing Triggers

The table below reflects the credit ratings for debt instruments of the Company at December 31, 2012. 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 and its access to the credit markets.

Rating Service	Senior Notes	Short-Term Rating	Outlook
Moody s Investors Service (Moody s)			