EQT Corp
Form 10-K
February 24, 2011
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010

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	**15222**
Pittsburgh, Pennsylvania	(Zip Code)

(Address of principal executive offices)

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

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

Title of each class	**Name of each exchange on which registered**
Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes _X_ No ___

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ___ No _X

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes _X_ No ___

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes _X_ No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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, 2010: $5,389,512,917

The number of shares of common stock outstanding

as of January 31, 2011: 149,171,339

DOCUMENTS INCORPORATED BY REFERENCE

The Company s definitive proxy statement relating to the annual meeting of shareowners (to be held May 10, 2011) will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2010 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, including the cost of financing construction of assets subject to regulation; 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 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.

CAP Customer Assistance Program - a payment plan for low-income residential gas customers that sets a fixed payment for natural gas usage based on a percentage of total household income. The cost of the CAP is spread across non-CAP customers.

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

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.

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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.

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 or 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.

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

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

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.

Abbreviations

ASC - Accounting Standards Codification

CBM Coalbed Methane

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

IRS Internal Revenue Service

LDC Local Distribution Company

NGV Natural Gas Vehicle

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

Dth = million British thermal units

Mcf = thousand cubic feet

Mcfe = thousand cubic feet of natural gas equivalents

Mgal = thousand gallons

MBbl = thousand barrels

MMBtu = million British thermal units

MMcf = million cubic feet

MMcfe = million cubic feet of natural gas equivalents

Tcfe = trillion cubic feet of natural gas equivalents

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Cautionary Statements

The Company s finding and development costs are calculated from the production cost and reserve information provided in Footnote 22 to the Consolidated Financial Statements as costs of oil and gas producing activities less unproved properties divided by changes in reserves excluding production. The Company expects that additional costs will be required to bring proved undeveloped reserves to production. The Company provides an estimate of future development costs under the standard measure of discounted cash flows in Footnote 22. The Company believes that finding and development costs are an important analytical measure used within the Company s industry by investors and peers to evaluate, among other things, the profitability of drilling programs. However, there are limitations as to the usefulness of this measure. For instance, this measure may not be calculated consistently across the industry.

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 forecasts, approximate, expect, project, intend, plan, believe and other words of similar meaning in connection with any discussion of operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this report include the matters discussed in the sections captioned 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 guidance regarding the Company s drilling and infrastructure programs (including the Equitrans Marcellus expansion project) and technology, transactions, including asset sales and /or joint ventures involving the Company s assets, the timing of construction of public-access natural gas refueling stations, production and sales volumes, well drilling plans, revenue projections, reserves (including estimated reserve life), the expected lateral length of wells, new fracturing techniques, finding and development costs, operating costs, well costs, unit costs, capital expenditures, financing requirements and availability, hedging strategy, the effects of government regulation and tax position. These statements 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. 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 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 statements, whether as a result of new information, future events or otherwise.

In reviewing any agreements incorporated by reference in or filed with this 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.

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PART I

Item 1. Business

General

EQT Corporation (EQT or the Company) conducts its business through three business segments: EQT Production, EQT Midstream and Distribution. EQT Production is one of the largest natural gas producers in the Appalachian Basin with 5.2 Tcfe of proved reserves across 3.5 million acres as of December 31, 2010. EQT Midstream provides gathering, transmission and storage services for the Company s produced gas and to independent third parties in the Appalachian Basin. Until February 1, 2011, EQT Midstream also provided processing services. Distribution, through its regulated natural gas distribution subsidiary, Equitable Gas Company, LLC (Equitable Gas), distributes and sells natural gas to residential, commercial and industrial customers in southwestern Pennsylvania, West Virginia and eastern Kentucky, operates a small gathering system in Pennsylvania and provides off-system sales activities which include the purchase and delivery of gas to customers.

EQT has 5.2 Tcfe of proved reserves across three major plays: Marcellus Shale, Huron Shale and CBM, all located in the Appalachian Basin. The Company s strategy is to maximize value by profitably developing its extensive acreage position. EQT Production is focused on continuing its significant organic reserve and production growth through its drilling program and believes that it is a technological leader in drilling shale.

EQT s proved reserves increased by 28% in 2010 and by 121% over the past five years, while the Company s cost structure remained at an industry leading level. EQT s 2010 finding and development cost is among the lowest in the industry at $0.70 per Mcfe. As of December 31, 2010, the Company s proved reserves, including proved developed and proved undeveloped reserves, and the resource plays to which the reserves relate are as follows:

(Bcfe)	Marcellus Shale	Huron *	Coalbed Methane	Total
Proved Developed	577	1,797	161	2,535
Proved Undeveloped	2,302	383		2,685
Total Proved Reserves	2,879	2,180	161	5,220

* The Company includes the Lower Huron, Cleveland, Berea sandstone and other Devonian shales, except Marcellus, in its Huron play. Also included in the Huron play is 705 Bcfe of reserves from non-shale formations accessed through vertical wells.

A key assumption in booking proved undeveloped reserves is the Company s 5-year capital investment estimate. The five-year plan used in estimating the Company s proved reserves anticipates drilling expenditures of $2.5 billion, which is consistent with the pace of development that the Company believes can be funded using the Production segment s portion of internally-generated cash flows and does not require additional capital infusions or asset sales. Assuming that future annual production from these reserves is consistent with 2010, the remaining reserve life of the Company s total proved reserves as calculated by dividing total proved reserves by current year produced volumes is in excess of 37 years.

The Company s natural gas wells are generally low-risk with long lives and low development and production costs. The gas produced from these wells has a high energy content and is within close proximity to natural gas markets. Many of these wells have been producing for decades, with several in production since early in the 20th century. Also, the gas produced from most of the Company s Huron wells and some of its Marcellus Shale wells is liquids-rich.

In the Marcellus Shale play, EQT applies proprietary extended lateral horizontal drilling technology to its approximate 520,000 acres and 2.9 Tcfe of proved reserves. Marcellus Shale wells target depths ranging from 7,000 to 8,000 feet with an average lateral spacing of 1,000 feet.

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EQT is also focusing its highly successful horizontal drilling program in the Huron play where the Company has approximately 2.7 million acres and 2.2 Tcfe of proved reserves. This technology has been used in fractured horizontal single lateral wells, stacked horizontal wells and extended lateral wells. Wells in the Huron play are drilled to depths ranging from 2,500 to 6,500 feet with an average lateral spacing of 1,000 feet.

Less than 5% of the Company s proved reserves are attributable to CBM as of December 31, 2010. Substantially all of the Company s CBM wells are drilled vertically and do not contain natural gas liquids.

Horizontal wells drilled by the Company over the past five years are as follows:

	For the years ended December 31,				
Gross Horizontal Wells Drilled	**2010**	**2009**	**2008**	**2007**	**2006**
Marcellus Shale	90	46	7		
Huron	236	356	381	88	5
Other		1	1		
Total Horizontal	326	403	389	88	5

The Company invested approximately $888 million on well development (primarily drilling) in 2010. Sales volumes increased 34% in 2010 over 2009.

During 2010, the Company acquired approximately 58,000 net acres in the Marcellus Shale from a group of private operators and landowners. The acreage is located primarily in Cameron, Clearfield, Elk and Jefferson counties in Pennsylvania. The purchase included a 200 mile gathering system, with associated rights of way, and approximately 100 producing vertical wells.

To support the growth of the Marcellus Shale play, the Company is increasing its available gathering and transmission system capacity in the region. During 2010, the Company completed construction of the Ingram Gathering system which added 4,800 horsepower of compression and 105 MMcfe per day of delivery capacity to Equitrans L.P. (Equitrans, EQT s interstate pipeline subsidiary) piplines for EQT production in Greene County, Pennsylvania. Equitrans has a total Pennsylvania gathering capacity of 130 MMcfe. In northern West Virginia, EQT completed the Doddridge Gathering System Expansion which is capable of delivering 60 MMcfe per day of EQT s production from north central West Virginia into the western leg of the Equitrans system. This brings total Marcellus Shale gathering capacity in West Virginia to approximately 85 MMcfe per day. Equitrans also completed Phase 1 of the Equitrans Marcellus expansion project which added approximately 100,000 Dth per day of new delivery capacity to Equitrans interconnections with five interstate pipeline facilities: Texas Eastern Transmission, Columbia Gas Transmission, National Fuel Gas Supply, Tennessee Gas Pipeline and Dominion Transmission.

Also, the Company has approximately 10,900 miles of gathering lines and 770 miles of transmission lines. EQT s 14 natural gas storage reservoirs provide approximately 500 MMcf per day of peak delivery capability and 63 Bcf of storage capacity, of which 32 Bcf is working gas. 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.

Through EQT s gas marketing subsidiary, EQT Energy, LLC, (EQT Energy), the Company provides optimization of capacity and storage assets, NGL sales and gas sales to commercial and industrial customers within its operational footprint through 8.2 Bcf of leased storage related assets and approximately 420,000 Dth per day of contractual pipeline capacity from third parties.

At December 31, 2010, EQT also owned and operated Kentucky Hydrocarbon, a gas processing facility in Langley, Kentucky. On February 1, 2011, EQT Midstream sold the processing facility and associated NGL pipeline

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to MarkWest Energy Partners, L.P. (MarkWest) for $230 million subject to customary purchase price adjustments. MarkWest agreed to commence the installation of a new 60 MMcfd cryogenic processing plant to expand the Langley cryogenic processing capacity. In conjunction with the closing of the sale of the Langley plant, EQT executed a long-term agreement with MarkWest to provide processing services for its Kentucky Huron Shale gas and extended its existing agreement with MarkWest for NGL transportation, fractionation, and marketing services until 2022. In addition, MarkWest has agreed to construct a natural gas processing facility in Logansport, WV by the second quarter of 2012. MarkWest will then provide natural gas processing services for EQT s Marcellus Shale production in north central West Virginia, as well as NGL transportation, fractionation and marketing services.

In 2008, EQT Energy executed a binding precedent agreement with Tennessee Gas Pipeline Company (TGP), a wholly owned subsidiary of El Paso Corporation, for a 15-year term that awarded the Company capacity in TGP s 300-Line expansion project. EQT Energy s capacity in the project is expected to be 350,000 Dth per day, giving EQT access to consumer markets from the Gulf Coast to the Mid-Atlantic and the Northeast. TGP s expected turn in line date for the 300-Line expansion project is late 2011.

Capital spending for well development (primarily drilling) in 2011 is expected to be approximately $691 million to support the drilling of up to 167 gross wells, including 86 gross Marcellus Shale wells, and approximately $244 million for midstream infrastructure. Sales volumes are expected to exceed 175 Bcfe for an anticipated natural gas sales volume growth of 30% in 2011. A substantial portion of the Company s 2011 drilling efforts are expected to be focused on drilling extended lateral Marcellus Shale wells. The Company currently believes that the capital spending plan will not require the Company to access capital markets through the end of the year.

Strategy

EQT s strategy is to maximize value by profitably developing the Company s substantial acreage position enabled by the Company s extensive gathering and transmission assets, low cost structure, close proximity to the northeastern United States markets and the high Btu content of much of its produced natural gas. The Company is focused on continuing its significant organic reserve and production growth through its developmental drilling program, particularly in the Marcellus Shale. The Company is also investing in developmental geological and geophysical studies to optimize well placement.

The Company believes that it is a technological leader in drilling shale. In the Marcellus Shale play, EQT Production believes its state of the art drilling and completion techniques have produced industry leading results. In the Huron play, the use of air in horizontal drilling has proven to be a cost effective technology which the Company has efficiently deployed. In both plays, the Company has used technology to increase lateral length. Recoveries from extended laterals have been proportional to the length increase. These industry leading processes have also allowed the Company to reduce development costs. Based on these favorable results, the Company has incorporated extended lateral wells into its preferred standard operating procedures for the Marcellus and Huron Shale plays. The Company expects to continue increasing the average lateral length. In the Marcellus Shale, lateral lengths will be limited by lease boundaries 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 economic manner rather than focusing on drilling less economic wells in order to retain acreage. Additionally, the Company continues to demonstrate the quality of its Marcellus Shale acreage with recent successful wells in North Central West Virginia and Central Pennsylvania. The Company s core development area in Greene County, Pennsylvania continues to produce industry leading Marcellus Shale results in terms of initial production rates and finding and development costs.

The Company believes the location of the Company s midstream assets across a wide area of the Marcellus Shale in southwestern Pennsylvania and northern West Virginia uniquely positions the Company for growth. In support of the Marcellus Shale growth, EQT Midstream strives to increase gathering capacity and improve capital efficiency by utilizing existing high pressure assets and completing modular compression construction. In West Virginia, completion of a compression facility has added significant capacity in the core Doddridge County area that the Company expects to develop in 2011.

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In 2011, EQT plans to continue its investment in gathering and transmission capacity in the high-potential Marcellus Shale area. This investment includes 130 MMcfe per day of incremental gathering capacity. In addition, over the next two years, the Equitrans Marcellus expansion project is expected to add approximately 550 MMcfe per day of incremental transmission capacity. The combination of these investments with the existing assets in the Huron region provide a platform for sales growth and will help to mitigate curtailments and increase the flexibility and reliability of the Company s gathering systems in transporting gas to market.

In light of the anticipated Marcellus Shale production growth, the Company is also considering partnering with third parties and other arrangements, including a potential sale of the Big Sandy Pipeline, to unlock the value of mature assets and redeploy such value into higher-growth Marcellus Shale development.

The Company is also helping to build demand for natural gas. As a result of the $700,000 grant received from the Pennsylvania Department of Environmental Protection, Equitable Gas will be constructing a public-access natural gas fueling station in Pittsburgh, PA. In conjunction with this project, the Company is promoting the use of NGV fleet vehicles. Distribution is actively increasing the supply of locally produced Marcellus Shale gas flowing to its customers and assisting customers to obtain incentives and rebates as a result of conversions to natural gas from other fuel sources.

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

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 evidenced by the significant increase in natural gas prices in early through mid 2008 followed by decreases later in 2008 and in 2009. The market price for gas located in the Appalachian Basin is generally higher than the price for gas located in the Gulf Coast, largely due to the differential in the cost to transport gas to customers in the northeastern United States. 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 outlined in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, and in Notes 1 and 3 to the Consolidated Financial Statements. No single customer accounted for more than 10% of revenues in 2010 or 2009. Sales to one third-party marketer accounted for approximately 13% of revenues for EQT Production for the year ended December 31, 2008.

NGL Sales: As of December 31, 2010, 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 EQT s Kentucky Hydrocarbon facility 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 the Kentucky Hydrocarbon facility to MarkWest, the processing of the Company s produced natural gas has been performed by a third-party vendor.

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Average well-head sales price:

	2010	2009	2008
Average well-head sales price per Mcfe sold (net of hedges)	$ 3.93	$ 4.11	$ 5.51
Average well-head sales price per Mcfe sold (excluding hedges)	$ 3.43	$ 2.79	$ 8.42

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 three major interstate pipelines: Columbia Gas Transmission, East Tennessee Natural Gas Company and Dominion Transmission. 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 2010 totaled 195,642 BBtu, of which approximately 67% related to gathering for EQT Production, 19% related to third-party volumes and 2% related to volumes for other subsidiaries of the Company. The remainder related to volumes in which interests were sold by the Company but which the Company continued to operate for a fee. Revenues from other subsidiaries accounted for approximately 85% of 2010 gathering revenues.

Natural Gas Transmission and Storage: Services offered by EQT Energy include commodity procurement, sales, delivery, risk management and other services, including the processing of natural gas liquids for third parties. These operations are executed using Company owned and operated or contracted 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. EQT Energy also engages in risk management and energy trading activities for the Company. The objective of these activities 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 2011 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 2010, approximately 85% of transportation volumes and approximately 89% of transportation revenues were from affiliates.

Natural Gas Distribution: The Company s Distribution segment provides natural gas distribution services to approximately 276,500 customers, consisting of 257,900 residential customers and 18,600 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. These 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 Gulf Coast, local 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 and WV PSC. Equitable Gas is not permitted to profit from fluctuations in gas costs.

Because most of its customers use natural gas for heating purposes, Equitable Gas revenues are seasonal, with approximately 71% of calendar year 2010 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

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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. Natural gas marketing activities compete with numerous other companies offering the same 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, the Company s distribution operation experiences only limited competition with other local distribution companies in its operating area, but experiences usuage 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, such as safety regulations. These regulations may impact the costs 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 laws generally limit the venting or flaring of natural gas.

EQT Midstream has both non-regulated and regulated operations. The interstate natural gas transmission systems and storage operations are regulated 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 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 trading activities which are regulated by, among others, the United States Commodity Futures Trading Commission (CFTC). In July 2010, federal legislation was enacted to implement various financial and governance reforms. Although many of the legislative provisions were focused on the financial and banking industries, portions of the legislation may impact the Company s natural gas trading activities. The extent of the impact is uncertain at this time because various implementing regulations are yet to be adopted by the SEC and the CFTC.

Equitable Gas distribution rates, terms of service and 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 Kentucky Public Service Commission.

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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 allowed 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. On August 24, 2010, the WV PSC approved a settlement between Equitable Gas and certain parties with respect to a base rate increase in West Virginia. Equitable Gas implemented the new base rates in the third quarter of 2010.

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. However, laws and regulations applicable to the oil and gas industry are frequently amended or reinterpreted. Moreover, the recent oil spill in the Gulf of Mexico and explosion of a natural gas transmission line in California may lead to new regulations, guidelines and enforcement interpretations. Therefore, the Company is unable to predict the future costs or impact of compliance. Additional proposals that affect the oil and gas industry are regularly considered by 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, or otherwise relating to 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, drilling, operating and abandoning wells and related surface facilities. In most instances, the regulatory frameworks relate to the handling of drilling and production materials, the disposal of drilling and production wastes, the protection of water and air and the protection of people.

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 formations are geologically separated and isolated from fresh ground water supplies by protective 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. 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 obtain permits for or 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

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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 approximately 1,815 employees at the end of 2010. As of December 31, 2010, approximately 12% of the Company s workforce is subject to collective bargaining agreements, and the collective bargaining agreement which covers approximately 9% of the Company s workforce is scheduled to expire during September 2011.

Holding Company Reorganization

On June 30, 2008, the former Equitable Resources, Inc. (Old EQT) entered into and completed an Agreement and Plan of Merger (the Plan) under which Old EQT reorganized into a holding company structure such that a newly formed Pennsylvania corporation, also named Equitable Resources, Inc. (New EQT), became the publicly traded holding company of Old EQT and its subsidiaries. The primary purpose of this reorganization (the Reorganization) was to separate Old EQT s state-regulated distribution operations into a new subsidiary in order to better segregate its regulated and unregulated businesses and improve overall financing flexibility. To effect the Reorganization, Old EQT formed New EQT, a wholly-owned subsidiary, and New EQT, in turn, formed EGC Merger Co., a Pennsylvania corporation owned solely by New EQT (MergerSub). Under the Plan, MergerSub merged with and into Old EQT with Old EQT surviving (the Merger). The Merger resulted in Old EQT becoming a direct, wholly-owned subsidiary of New EQT. New EQT changed its name to EQT Corporation effective February 9, 2009. Throughout this Annual Report, references to EQT, EQT Corporation and the Company refer collectively to New EQT and its consolidated subsidiaries.

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.

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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 during the years 2010, 2009 and 2008.

	2010	2009	2008
EQT Production:			
Natural gas sales	25%	24%	20%
EQT Midstream:			
Gathering revenue	13%	11%	7%
Marketed natural gas sales	6%	5%	12%
Distribution:			
Residential natural gas sales	21%	26%	23%

Financial Information About Segments

On February 1, 2011, the Company sold its natural gas processing complex in Langley, Kentucky. Subsequent to the closing of the sale, the processing of the Company s produced natural gas has been performed by a third-party vendor. The revenue received as a result of the fractionation of NGLs which were extracted from the Company s produced natural gas (frac spread) was previously reported in the EQT Midstream segment in conjunction with the results of the processing activities. As a result of the sale of the Company s processing assets, management determined that this frac spread would be reported in the EQT Production segment as additional revenue for its produced NGL sales. The segment disclosures and discussions contained in this report have been reclassified to reflect all periods presented under the new methodology.

See Note 2 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.

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.

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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 proximity to, and availability of capacity on, transportation 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 the construction of new transportation capacity and downward adjustments to the value of our estimated proved reserves 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 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 natural gas liquids. 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 and pollution or other environmental damage. As a result, we are 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.

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, the recent oil spill in the Gulf of Mexico, the explosion of a natural gas transmission line in California and concerns raised by advocacy groups about hydraulic fracturing, may lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations, which 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.

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 2011 business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, 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 2011 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, 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.

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 prospect 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, our 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, 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.

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.

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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.

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 and a qualified work force, as well as weather conditions, gas price volatility, government approvals, title problems, geology 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.

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, restoration of drilling properties after drilling is completed, pipeline safety 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. 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, effective January 1, 2011, the EPA began regulating greenhouse gas emission 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.

In addition, 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 and the release, capture and use of greenhouse gases that could have an adverse effect on our operations.

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In addition, hydraulic fracturing is utilized 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 by some members of Congress to provide for such regulation. We cannot predict whether any such federal or state legislation or regulation will be enacted and if enacted how they may impact our operations, but enactment of additional laws or regulations could increase our operating costs.

Recent federal budget proposals have included provisions which could potentially increase and accelerate the payment of federal income taxes of independent producers of natural gas and oil. Proposals that would significantly affect us would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses. 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, federal legislation was enacted to implement various financial and governance reforms. Although many of the legislative provisions were focused on the financial and banking industries, portions of the legislation will impact our businesses. The extent of the impact is uncertain at this time, due to the requirement that various implementing regulations must be adopted by the SEC and the United States Commodity Futures Trading Commission.

Our failure to develop or obtain, and 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 of adequate transportation infrastructure. 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 processing adjacent to and curtailments on such pipelines. The lack of midstream infrastructure could become more important in the geographic area in which the Marcellus Shale is being developed. 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 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 gathering, transportation, processing and storage facilities which are limited in number and geographically concentrated. An extended interruption of access to or service from these facilities could result in adverse consequences to us. In addition, some of our third-party contracts may involve significant financial commitments on our part and may make us dependent upon others to get our produced natural gas to market.

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 personnel and certain other professionals. 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.

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.

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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 (1) 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 (2) 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 Kentucky, West Virginia, Virginia and Pennsylvania. This segment currently has approximately 3.5 million gross acres (approximately 63% of which are considered undeveloped), which encompasses substantially all of the Company s acreage of proved developed and undeveloped natural gas and oil production properties. 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, 2010, the Company estimated its total proved reserves to be 5,220 Bcfe, consisting of proved developed producing reserves of 2,177 Bcfe, proved developed non-producing reserves of 358 Bcfe and proved undeveloped reserves of 2,685 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 the technical aspects of the reserves audit has received a bachelor s degree in Engineering from the Pennsylvania State University and has thirteen 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, production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems and the reserve roll forward 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 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 22 (unaudited) to the Consolidated Financial Statements.

In 2010, the Company commenced drilling operations (spud or drilled) on 90 gross horizontal wells with an aggregate of approximately 300,000 feet of pay in the Marcellus Shale play. Total proved reserves in the Marcellus Shale play increased 171% to 2.9 Tcfe. Proved reserves increased in the Marcellus Shale play as a result of the Company s 2010 drilling program. In the Huron play, the Company drilled 236 gross horizontal wells with an aggregate of approximately 1.0 million feet of pay during 2010. Total proved reserves in the Huron play (including vertical non-shale formations) decreased 22% to 2.2 Tcfe. The Company drilled 95 gross CBM wells in 2010. The CBM play had total proved reserves of 0.2 Tcfe at December 31, 2010, down 25% from 2009. Proved reserves decreased in the Huron and CBM plays as the Company plans to focus its capital expenditures during the next five years on developing the Marcellus Shale play. Sales of produced natural gas in 2010 from the Marcellus Shale, Huron and CBM plays were 25.5 Bcfe, 95.6 Bcfe and 13.5 Bcfe, respectively. Over the past three years, the Company has experienced a 99.6% developmental drilling success rate.

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Natural gas, NGL and crude oil production and pricing:

	2010	2009	2008
Natural Gas:			
MMcf produced	127,847	95,779	84,080
Average well-head sales price per Mcfe sold (net of hedges)	$ 3.14	$ 3.61	$ 4.76
NGLs:			
Thousands of Bbls produced	2,712	2,219	1,525
Average sales price per Bbl	$ 48.76	$ 35.21	$ 55.35
Crude Oil:			
Thousands of Bbls produced	120	99	104
Average sales price per Bbl	$ 70.23	$ 49.62	$ 96.11

The Company s average per unit production cost, excluding severance taxes, of natural gas and crude oil during 2010, 2009 and 2008 was $0.24, $0.30 and $0.35 per Mcfe, respectively.

	Natural Gas	Oil
Total productive wells at December 31, 2010:		
Total gross productive wells	14,305	20
Total net productive wells	10,389	17
Total in-process wells at December 31, 2010:		
Total gross in-process wells	129	
Total net in-process wells	110	
	(MMcf)	(MBbls)
Summary of proved oil and gas reserves as of December 31, 2010 based on average fiscal-year prices:		
Developed	2,520,569	2,307
Undeveloped	2,685,123	

Total acreage at December 31, 2010:	
Total gross productive acres	1,267,324
Total net productive acres	1,104,980
Total gross undeveloped acres	2,190,885
Total net undeveloped acres	1,910,234

Certain lease acquisition agreements require the Company to drill 5 wells drilled to 250 above the top of the Tully formation or deeper plus 4 wells to any depth or formation in 2011 and 5 wells drilled to 250 above the top of the Tully formation or deeper plus 2 wells to any depth or formation in 2012; each of these wells must be drilled within specified acreage. The Company intends to satisfy these requirements as part of its Marcellus Shale development program. As of December 31, 2010, leases associated with 16,431 gross undeveloped acres expire in 2011 if they are not renewed; however, the Company has an active lease renewal program.

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

	2010	2009	2008
Exploratory wells:			
Productive			1.0
Dry		1.0	
Development wells:			
Productive	392.1	535.6	531.2
Dry	3.0	2.0	1.0

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Selected data by state (at December 31, 2010 unless otherwise noted):

	Kentucky	West Virginia	Virginia	Pennsylvania	Ohio	Total
Natural gas and oil production (MMcfe) 2010	58,592	35,199	25,985	19,245		139,021
Natural gas and oil production (MMcfe) 2009	50,959	27,069	24,624	2,276		104,928
Natural gas and oil production (MMcfe) 2008	42,798	23,054	23,192	1,541		90,585
Average net revenue interest (%)	90.1%	74.1%	50.2%	87.0%		75.8%
Total gross productive wells	5,508	4,873	3,230	714		14,325
Total net productive wells	4,640	3,118	1,938	710		10,406
Total gross productive acreage	520,240	417,404	267,680	62,000		1,267,324
Total gross undeveloped acreage	932,414	785,489	276,758	193,921	2,303	2,190,885
Total gross acreage	1,452,654	1,202,893	544,438	255,921	2,303	3,458,209
Total net productive acreage	453,597	363,945	226,316	61,122		1,104,980
Total net undeveloped acreage	930,497	658,743	125,323	193,368	2,303	1,910,234
Total net acreage	1,384,094	1,022,688	351,639	254,490	2,303	3,015,214
Proved developed producing reserves (Bcfe)	1,097	575	323	182		2,177
Proved developed non-producing reserves (Bcfe)	19	198	5	136		358
Proved undeveloped reserves (Bcfe)	384	832		1,469		2,685
Proved developed and undeveloped reserves (Bcfe)	1,500	1,605	328	1,787		5,220
Gross proved undeveloped drilling locations	311	201		265		777
Net proved undeveloped drilling locations	311	201		265		777

During 2010, the Company converted 249 Bcfe of proved undeveloped reserves to proved developed reserves and 362 Bcfe of non-proved undeveloped reserves to proved developed reserves. The five-year plan used in estimating proved reserves anticipates drilling expenditures of $2.5 billion to convert proved undeveloped reserves to proved developed reserves. This level of spending is consistent with the pace of development that the Company believes can be funded using the Production segment s portion of internally-generated cash flows and does not require additional capital infusions or asset sales. Capital expenditures at EQT Production totaled $1,246 million during 2010, including $357.7 million for the acquisition of undeveloped property. As a result of the Company s 2010 drilling program, the increase in proved reserves was primarily due to increases in the Marcellus Shale play offset by decreases in the Huron and CBM plays.

The Company s 2010 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 1,893 Bcfe exceeded the 2010 production of 139.0 Bcfe.

During 2010, the Company recorded downward revisions of 604 Bcfe to the December 31, 2009 estimate of proved reserves due to removing PUD locations in the Huron play in order to focus more capital and resources in the Marcellus Shale play over the five-year time horizon included in the PUD development plan. These downward

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revisions were partially offset by increased prices. The reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2010. Although proved reserves are sensitive to price volatility, the impact to the Company should be minimal due to the Company s low cost structure. Instead, proved reserve quantities are confined by the capital available for the development program within the next 5 years.

Wells located in Kentucky are primarily in Huron Shale formation with depths ranging from 2,500 feet to 6,000 feet. Wells located in West Virginia are primarily in Huron and Marcellus Shale formations with depths ranging from 2,500 feet to 6,500 feet. Wells located in Virginia are primarily in coalbed methane formations with depths ranging from 2,000 feet to 3,000 feet. Wells located in Pennsylvania are primarily in Marcellus Shale formations with depths ranging from 7,000 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 10,900 miles of gathering line and 243 compressor units comprising 125 compressor stations with approximately 228,000 horsepower of installed capacity, as well as other general property and equipment.

Substantially all of the gathering operations 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.

	Kentucky	**West Virginia**	**Virginia**	**Pennsylvania**	**Total**
Approximate miles of gathering line	3,850	4,850	1,700	500	10,900

EQT Midstream also owns and operates regulated underground storage and transmission facilities in Pennsylvania, West Virginia and Kentucky. These operations consist of approximately 770 miles of regulated transmission with daily capacity of 830,000 Dth per day and storage lines with approximately 28,000 horsepower of installed capacity and interconnections with five major interstate pipelines. The interstate pipeline system stretches throughout north central West Virginia and southwestern Pennsylvania. Equitrans has 14 natural gas storage reservoirs with approximately 500 MMcf per day of peak delivery capability and 63 Bcf of storage capacity, of which 32 Bcf is working gas. These storage reservoirs are geographically clustered, with eight in northern West Virginia and six in southwestern Pennsylvania.

As of December 31, 2010, the Midstream business also owned a hydrocarbon processing plant and gas compression facilities located in Langley, Kentucky (Kentucky Hydrocarbon). On February 1, 2011, EQT sold Kentucky Hydrocarbon to MarkWest.

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

Equitable 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. In 2008, the Company entered into an agreement with Liberty Avenue Holdings, LLC to lease office space in Pittsburgh, Pennsylvania for the Company s new corporate headquarters. During the third quarter of 2009, the Company completed the relocation of its corporate headquarters and certain other operations to downtown Pittsburgh.

Item 3. Legal Proceedings

In the ordinary course of business various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict

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with certainty the ultimate outcome of such claims and proceedings. The Company has established reserves for pending litigation, which it believes are adequate, 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.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of the Company s security holders during the last quarter of its fiscal year ended December 31, 2010.

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Executive Officers of the Registrant (as of February 24, 2011)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Theresa Z. Bone (47)	Vice President and Corporate Controller (2007)	Elected to present position July 2007; Vice President and Controller of Equitable Utilities from December 2004 until July 2007.
Philip P. Conti (51)	Senior Vice President and Chief Financial Officer (2000)	Elected to present position February 2007; Vice President and Chief Financial Officer from January 2005 to February 2007, also Treasurer until January 2006.
Randall L. Crawford (48)	Senior Vice President and President, Midstream, Commercial and Distribution (2003)	Elected to present position in April 2010; Senior Vice President Midstream and Distribution from January 2008 to April 2010. Senior Vice President, and President, Equitable Utilities from February 2007 to December 2007; Vice President, and President, Equitable Utilities from February 2004 to February 2007.
Martin A. Fritz (46)	Vice President and President, Midstream Operations (2006)	Elected to current position April 2010; Vice President and President Midstream from January 2008 to April 2010. Vice President and Chief Administrative Officer from February 2007 to December 2007; Vice President and Chief Information Officer from April 2006 to February 2007; Chief Information Officer from May 2003 to March 2006.
Lewis B. Gardner (53)	Vice President and General Counsel (2008)	Elected to present position April 2008; Managing Director External Affairs and Labor Relations from January 2008 to March 2008; Senior Counsel - Director Employee and Labor Relations from March 2004 to December 2007.
Murry S. Gerber (57)	Executive Chairman (1998)	Elected to present position April 2010. Chairman and Chief Executive Officer from February 2007 to April 2010; Chairman, President and Chief Executive Officer from May 2000 to February 2007.
M. Elise Hyland (51)	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 July 2007 to January 2008; Senior Vice President, Customer Operations Equitable Gas Company from March 2004 to June 2007.
Charlene Petrelli (50)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007; Vice President, Human Resources from January 2003 to February 2007.
David L. Porges (53)	President and Chief Executive Officer (1998)	Elected to present position April 2010; President and Chief Operating Officer from February 2007 to April 2010; Vice Chairman and Executive Vice President, Finance and Administration from January 2005 to February 2007.
Steven T. Schlotterbeck (45)	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; Executive Vice President, Exploration and Development, Equitable Production Company (EPC) from July 2007 to December 2007; Managing Director, Exploration and Production Planning and Development, EPC from January 2006 to June 2007.

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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, are summarized as follows (in U.S. dollars per share):

	2010			2009		
	High	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st Quarter	$ 47.43	$ 39.78	$ 0.22	$ 38.63	$ 27.77	$ 0.22
2nd Quarter	46.06	35.80	0.22	38.95	31.38	0.22
3rd Quarter	39.50	32.23	0.22	42.90	31.94	0.22
4th Quarter	45.23	36.01	0.22	45.74	40.54	0.22

As of January 31, 2011, there were 3,402 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 on certain business conditions, such as the Company s lines of business, results of operations and financial conditions, strategic direction and other factors.

Stock Performance Graph

The following graph compares the most recent five-year cumulative total return attained by shareholders on the Company s common stock with the cumulative total returns of the S&P 500 index and a customized peer group of twenty companies (the Self-Constructed Peer Group) whose individual companies are listed in footnote (1) below. An investment of $100 (with reinvestment of all dividends) is assumed to have been made at the close of business on December 31, 2005 in the Company s common stock, in the S&P 500 index, and in the peer group. Relative performance is tracked through December 31, 2010.

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	12/05	12/06	12/07	12/08	12/09	12/10
EQT Corporation	**100.00**	**116.51**	**151.30**	**97.01**	**129.92**	**135.58**
S&P 500	**100.00**	**115.80**	**122.16**	**76.96**	**97.33**	**111.99**
Self-Constructed Peer Group	**100.00**	**116.13**	**143.62**	**89.70**	**129.18**	**139.58**

(1) The twenty companies included in the self constructed peer group are: Atlas Energy Resources LLC, Cabot Oil & Gas Corp., Chesapeake Energy Corp., CNX Gas Corporation, El Paso Corp., Enbridge Inc., Energen Corp., Markwest Energy Partners LP, MDU Resources Group Inc, National Fuel Gas Company, Oneok Inc., Penn Virginia Corp., Questar Corp., Range Resources Corp., Sempra Energy, Southern Union Company, Southwestern Energy Company, Spectra Energy Corp., Transcanada Corp. and The Williams Companies, Inc. Atlas Energy Resources LLC was acquired during 2009 and is included in the calculation from December 31, 2005 through December 31, 2008, at which time it is removed from the peer group calculation. CNX Gas Corporation was acquired during 2010 and is included in the calculation from December 31, 2005 through December 31, 2009, at which time it is removed from the peer group calculation. Questar Corp. was calculated using historical split adjusted pricing data.

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

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Item 6. Selected Financial Data

	As of and for the years ended December 31,				
	2010	2009	2008	2007	2006
	(Thousands, except per share amounts)				
Operating revenues	$ 1,322,708	$ 1,269,827	$ 1,576,488	$ 1,361,406	$ 1,267,910
Net income	$ 227,700	$ 156,929	$ 255,604	$ 257,483	$ 216,025
Earnings per share					
Basic	$ 1.58	$ 1.20	$ 2.01	$ 2.12	$ 1.79
Diluted	$ 1.57	$ 1.19	$ 2.00	$ 2.10	$ 1.77
Total assets	$ 7,098,438	$ 5,957,257	$ 5,329,662	$ 3,936,971	$ 3,282,255
Long-term debt	$ 1,949,200	$ 1,949,200	$ 1,249,200	$ 753,500	$ 763,500
Cash dividends declared per share of common stock	$ 0.880	$ 0.880	$ 0.880	$ 0.880	$ 0.870

See Item 1A, Risk Factors and Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Notes 5 and 6 to the Consolidated Financial Statements for 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 2010 EQT achieved record results. Highlights for 2010 include:

- Record annual sales of produced natural gas of 134.6 Bcfe, more than 34% higher than 2009;
- A 28% increase in proved reserves to 5.2 Tcfe;
- The Company drilled 489 gross wells during 2010, of which 326 were horizontal wells, 90 targeting the Marcellus Shale play and 236 targeting the Huron play;
- The Company was successful on more than 99.6% of the wells drilled in 2010;
- Achieved 20% decrease in unit lease operating expense (LOE), excluding production taxes, to $0.24 per Mcfe. Including production taxes, LOE was $0.48 per Mcfe;
- Record EQT Midstream throughput and operating income; and
- Record Distribution operating income of $83.2 million, 5% higher than 2009.

EQT s consolidated net income for 2010 was $227.7 million, $1.57 per diluted share, compared with $156.9 million, $1.19 per diluted share, for 2009 and $255.6 million, $2.00 per diluted share, for 2008.

The $70.8 million increase in net income from 2009 to 2010 was primarily attributable to increased produced natural gas sales volumes, higher gathering revenues, increased net revenues for NGLs, lower long-term incentive compensation expense and lower exploration expense. These favorable variances were partially offset by increased depreciation, depletion and amortization, lower average well-head sales prices, lower storage and marketing revenues and higher interest expense.

EQT revenues for 2010 increased approximately 4% compared to 2009 revenues. Gas sales volumes increased more than 34% from 2009 primarily as a result of increased production from the 2009 and 2010 drilling programs partially offset by the normal production decline in the Company s producing wells. Gathered volumes increased due to the Company s production growth and infrastructure expansion, and NGL sales revenues increased as a result of an increase in NGL sales price as well as an increase in NGLs sold. Residential revenues increased as a result of the Company s base rate increases in February 2009 and August 2010. These increases were partially offset by a 4% decline in the average well-head sales price as a result of lower hedge prices year-over-year which more than offset slightly increased commodity market prices and a 7% decline in storage and marketing revenues primarily resulting from lower margins on pipeline capacity.

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Operating expenses for 2010 decreased approximately 7% compared to 2009. This decline was primarily attributable to a $118.2 million decrease in purchased gas costs due to lower recoverable commodity costs, a $39.3 million decrease in long-term incentive compensation expense primarily due to the Company s share price and performance in relation to its peer group which resulted in $61.8 million of expense in 2009 and a $12.5 million decrease in the Company s exploration program. The decrease in exploration expense is primarily a result of a reduction in the level of purchase and interpretation of seismic data for unproved properties. These decreases were partially offset by higher depletion resulting from increased investment in oil and gas producing properties.

The $98.7 million decrease in net income from 2008 to 2009 was primarily attributable to a lower average well-head sales price, increased incentive compensation expense, increased depletion expense and higher interest expense partially offset by increased gas and NGL sales volumes at EQT Production, increased gathering revenues, Big Sandy Pipeline activity at EQT Midstream and an increase in base rates in the Distribution segment.

Incentive compensation expense increased from 2008 to 2009 and decreased from 2009 to 2010 as a result of expenses related to the Company s 2009 Shareholder Value Plan recorded in 2009 and a reversal of previously recorded expense on the Company s 2005 Executive Performance Incentive Program in 2008 primarily as a result of the decline in the Company s stock price in 2008. Incentive compensation is primarily reported in selling, general and administrative expenses in the Statements of Consolidated Income. A significant portion of the 2009 expense and 2008 reversal are reported as unallocated expenses in the information by business segment in Note 2 of the Company s Consolidated Financial Statements.

Interest expense increased from 2008 to 2009 and from 2009 to 2010 primarily due to the Company s continued investment in drilling and midstream infrastructure. This investment was partially funded by the issuance of $700 million of 8.125% notes in May 2009.

See Investing Activities in Capital Resources and Liquidity for a discussion of capital expenditures.

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, equity in earnings of nonconsolidated investments and other income. Interest expense 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 are not allocated to the operating segments. Certain performance-related incentive compensation expenses (income) and administrative expenses totaling $15.1 million, $62.2 million and ($17.4) million in 2010, 2009 and 2008, respectively, were not allocated to business segments. The unallocated expenses in 2010 and 2009 primarily relate to performance-related incentive compensation expenses, while the unallocated income in 2008 primarily relates to the reversal of previously recorded performance-related incentive compensation expenses.

The Company has reconciled each segment s operating income, equity in earnings of nonconsolidated investments and other income to the Company s consolidated operating income, equity in earnings of nonconsolidated investments and other income totals in Note 2 to the Consolidated Financial Statements. Additionally, these subtotals are reconciled to the Company s consolidated net income in Note 2. The Company has also 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 is useful to management and investors in assessing the financial condition, operations and trends of each of EQT s segments without being obscured by these items for the other segments or by the effects of corporate allocations. In addition, management uses these measures for budget planning purposes.

On February 1, 2011, the Company sold its natural gas processing complex in Langley, Kentucky. Subsequent to the closing of this sale, the processing of the Company s produced natural gas has been performed by a third-party vendor. The revenue received as a result of the fractionation of NGLs which were extracted from

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the Company s produced natural gas (frac spread) was previously reported in the EQT Midstream segment in conjunction with the results of the processing activities. As a result of the sale of the Company s processing assets, management determined that this frac spread would be reported in the EQT Production segment as additional revenue for its produced NGL sales. The segment disclosures and discussions contained in this report have been reclassified to reflect all periods presented under the new methodology. In conjunction with the closing of the sale, the Company executed a long-term agreement to receive processing services for its Kentucky Huron Shale gas and extended its existing agreement for NGL transportation, fractionation and marketing services until 2022. Expenses incurred during 2010 to operate the Langley processing complex, excluding DD&A, were $20.2 million. If the natural gas volumes processed by the Langley facility in 2010 would have been processed by a third-party, the Company would have incurred approximately $35.1 million in processing fees and expenses.

EQT Production

Results of Operations

	Years Ended December 31,				
	2010	**2009**	**% change 2010 - 2009**	**2008**	**% change 2009 - 2008**
OPERATIONAL DATA					
Production:					
Natural gas, NGL and crude oil production (MMcfe) (a)	139,021	104,928	32.5	90,585	15.8
Company usage, line loss (MMcfe)	(4,407)	(4,828)	(8.7)	(6,577)	(26.6)
Total sales volumes (MMcfe)	134,614	100,100	34.5	84,008	19.2
Natural gas sales volumes (MMcf)	123,440	90,951	35.7	77,503	17.4
NGL sales volumes (Mbbls)	2,712	2,219	22.2	1,525	45.5
Crude oil sales volumes (Mbbls)	120	99	21.2	104	(4.8)
Total sales volumes (MMcfe) (b)	134,614	100,100	34.5	84,008	19.2
Average (well-head) sales price (c)	$ 3.93	$ 4.11	(4.4)	$ 5.51	(25.4)
Lease operating expenses (LOE), excluding production taxes ($/Mcfe)	$ 0.24	$ 0.30	(20.0)	$ 0.35	(14.3)
Production taxes ($/Mcfe)	$ 0.24	$ 0.30	(20.0)	$ 0.53	(43.4)
Production depletion ($/Mcfe)	$ 1.26	$ 1.06	18.9	$ 0.81	30.9
Production depletion (thousands)	$ 175,629	$ 111,371	57.7	$ 73,362	51.8
Other depreciation, depletion and amortization (DD&A) (thousands)	8,070	6,053	33.3	4,872	24.2
Total DD&A (thousands)	$ 183,699	$ 117,424	56.4	$ 78,234	50.1
Capital expenditures (thousands) (d)	$ 1,245,914	$ 717,356	73.7	$ 700,745	2.4

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	Years Ended December 31,				
	2010	**2009**	**% change 2010 - 2009**	**2008**	**% change 2009 - 2008**
FINANCIAL DATA (thousands)					
Total operating revenues	$ 537,657	$ 420,990	27.7	$ 472,961	(11.0)
Operating expenses:					
LOE, excluding production taxes	33,784	31,228	8.2	31,719	(1.5)
Production taxes (e)	33,630	31,750	5.9	48,139	(34.0)
Exploration expense	5,368	17,905	(70.0)	9,064	97.5
Selling, general and administrative (SG&A)	57,689	36,815	56.7	38,185	(3.6)
DD&A	183,699	117,424	56.4	78,234	50.1
Total operating expenses	314,170	235,122	33.6	205,341	14.5
Operating income	$ 223,487	$ 185,868	20.2	$ 267,620	(30.5)

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

(b) NGLs are converted to Mcfe at the rate of 3.86 Mcf per barrel and crude oil is converted to Mcfe at the rate of six Mcf per barrel.

(c) Average well-head sales price is calculated as market price adjusted for hedging activities less deductions for gathering, processing and transmission included in EQT Midstream revenues. These deductions totaled $1.69/Mcfe, $1.69/Mcfe and $1.50/Mcfe for 2010, 2009 and 2008, respectively. Additionally, third-party gathering, processing and transportation deductions totaled $0.42/Mcfe, $0.36/Mcfe and $0.43/Mcfe for 2010, 2009 and 2008, respectively.

(d) Capital expenditures in 2010, 2009 and 2008 include $357.7 million, $31.0 million and $85.5 million, respectively, for undeveloped property acquisitions. The amount for 2010 includes $230.7 million of undeveloped property which was acquired with EQT stock.

(e) Production taxes include severance and production-related ad valorem and other property taxes.

Fiscal Year Ended December 31, 2010 vs. December 31, 2009

EQT Production s operating income totaled $223.5 million for 2010 compared to $185.9 million for 2009, an increase of $37.6 million between years, primarily due to increased sales volumes of produced natural gas, NGL and crude oil, partially offset by a lower average well-head sales price and an increase in depletion and SG&A expenses.

Total operating revenues were $537.7 million for 2010 compared to $421.0 million for 2009. The $116.7 million increase in operating revenues was due to increased sales volumes which more than offset lower realized prices. The increase in produced natural gas sales volumes was the result of increased production from the 2009 and 2010 drilling programs, primarily in the Marcellus and Huron Shale plays. This increase was partially offset by the normal production decline in the Company s wells. The $0.18 per Mcfe decrease in the average well-head sales price was primarily due to lower hedging gains and lower hedged gas sales compared to 2009, partially offset by a 10% increase in the average NYMEX price and a higher sales price for NGLs.

Operating expenses totaled $314.2 million for 2010 compared to $235.1 million for 2009. The 34% increase in operating expenses was primarily the result of increases of $66.3 million in DD&A, $20.9 million in SG&A, $2.6

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million in LOE partially offset by a decrease of $12.5 million in exploration expense. The increase in DD&A was primarily due to increased depletion expense resulting from both increases in the unit rate ($25.6 million) and volume ($38.2 million). The $0.20 per Mcfe increase in the depletion rate is primarily attributable to the increased investment in oil and gas producing properties. The increase in SG&A was primarily due to the reversal of reserves in the prior year for certain legal disputes; higher personnel costs including incentive compensation and hiring and relocation costs, a portion of which were recorded at headquarters in prior years; a charge for the buy-out of excess contractual capacity for the processing and disposal of salt water; and an increase in professional fees. Despite the 20% decrease in the average LOE per Mcfe, total LOE increased as a result of increased activity in the Marcellus Shale play in the current year. These factors were partially offset by a decrease in exploration expense due to a reduction in geophysical activity compared to the prior year as well as an impairment charge in 2009 on an exploratory Utica well.

Fiscal Year Ended December 31, 2009 vs. December 31, 2008

EQT Production s operating income totaled $185.9 million for 2009 compared to $267.6 million for 2008, a decrease of 31% between years, primarily due to a lower average well-head sales price and an increase in depletion expense partially offset by increased sales volumes.

Total operating revenues were $421.0 million for 2009 compared to $473.0 million for 2008. The decrease in operating revenues was due to lower realized prices which more than offset increased sales volumes. The average well-head sales price decreased by $1.40 per Mcfe, primarily as a result of a 56% decrease in NYMEX natural gas prices, a 36% lower sales price for NGLs and a lower percentage of hedged gas sales, partially offset by a higher realized hedge price. The decrease in prices was partially offset by increased sales volumes of more than 19% as a result of the 2008 and 2009 drilling programs, net of the normal production decline in the Company s wells, and a decrease in Company usage and line loss.

Operating expenses totaled $235.1 million for 2009 compared to $205.3 million for 2008. The $29.8 million increase in operating expenses was a result of increases of $39.2 million in DD&A partially offset by decreases of $16.4 million in production taxes, $1.4 million in SG&A, and $0.5 million in LOE. In addition, 2009 includes an $8.8 million increase in exploration expense due to the purchase and interpretation of seismic data in support of the Company s examination of emerging plays and the impairment charge on an exploratory Utica well. The increase in DD&A was primarily due to increased depletion expense resulting from both increases in the unit rate ($26.3 million) and volume ($11.0 million). The $0.25 per Mcfe increase in the depletion rate is primarily attributable to the increased investment in oil and gas producing properties. The decrease in production taxes was primarily due to a $17.8 million decrease in severance taxes partially offset by a $1.4 million increase in property taxes. The decrease in severance taxes (a production tax imposed on the value of gas extracted) was primarily due to lower gas commodity prices partially offset by higher sales volumes in the various taxing jurisdictions that impose such taxes. The increase in property taxes was a direct result of increased prices and sales volumes in prior years, as property taxes in several of the taxing jurisdictions where the Company s wells are located are calculated based on historical gas commodity prices and sales volumes. The decrease in SG&A was primarily due to the reversal of reserves for certain legal disputes partially offset by higher overhead costs associated with the growth of the Company, increased franchise and gross receipts taxes attributable to increased receipts and costs associated with the amendment of a contract to secure capacity for the processing and disposal of salt water. The decrease in LOE was primarily attributable to the 2008 program to test the re-fracturing of existing wells.

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EQT Midstream

Results of Operations

	Years Ended December 31,				
	2010	2009	% change 2010 - 2009	2008	% change 2008 - 2007
OPERATIONAL DATA					
Gathering and processing:					
Gathered volumes (BBtu)	195,642	161,480	21.2	145,031	11.3
Average gathering fee ($/MMBtu)	$ 1.11	$ 1.04	6.7	$ 0.98	6.1
Gathering and compression expense ($/MMBtu) (a)	$ 0.37	$ 0.42	(11.9)	$ 0.37	13.5
Transmission pipeline throughput (BBtu)	109,165	84,132	29.8	76,270	10.3
Net operating revenues (thousands):					
Gathering	$ 212,170	$ 165,519	28.2	$ 140,118	18.1
Transmission	84,190	76,749	9.7	51,563	48.8
Storage, marketing and other	100,097	107,530	(6.9)	95,842	12.2
Total net operating revenues	$ 396,457	$ 349,798	13.3	$ 287,523	21.7
Capital expenditures (thousands)	$ 193,128	$ 201,082	(4.0)	$ 593,564	(66.1)
FINANCIAL DATA (thousands)					
Total operating revenues	$ 580,698	$ 465,444	24.8	$ 597,073	(22.0)
Purchased gas costs	184,241	115,646	59.3	309,550	(62.6)
Total net operating revenues	396,457	349,798	13.3	287,523	21.7
Operating expenses:					
Operating and maintenance (O&M)	107,601	95,164	13.1	83,577	13.9
SG&A	48,127	47,146	2.1	49,208	(4.2)
DD&A	61,863	53,291	16.1	34,802	53.1
Total operating expenses	217,591	195,601	11.2	167,587	16.7
Operating income	$ 178,866	$ 154,197	16.0	$ 119,936	28.6
Other income, net	$ 509	$ 1,357	(62.5)	$ 5,678	(76.1)
Equity in earnings of nonconsolidated investments	$ 9,532	$ 6,376	49.5	$ 5,053	26.2

(a) The calculation of gathering and compression expense ($/MMBtu) for 2008 excludes a $9.5 million charge for pension and other post-retirement benefits.

Fiscal Year Ended December 31, 2010 vs. December 31, 2009

EQT Midstream s operating income totaled $178.9 million for 2010 compared to $154.2 million for 2009. The $24.7 million increase in operating income was primarily the result of increased gathering volumes and

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gathering rates, partially offset by decreased storage, marketing and other net operating revenues and increased operating expenses.

Total net operating revenues were $396.5 million for 2010 compared to $349.8 million for 2009. The $46.7 million increase in total net operating revenues was due to a $46.7 million increase in gathering net operating revenues and a $7.4 million increase in transmission net operating revenues, partially offset by a $7.4 million decrease in storage, marketing and other net operating revenues.

Gathering net operating revenues increased due to a 21% increase in gathered volumes as well as a 7% increase in the average gathering fee. This increase was driven primarily by higher Marcellus Shale volumes from EQT Production.

Transmission net revenues in 2010 increased from the prior year primarily as a result of higher firm transportation activity from affiliated shippers due to the increased Marcellus Shale volumes and increased capacity from Phase 1 of the Equitrans Marcellus expansion project, which came on-line during the fourth quarter of 2010.

The decrease in storage, marketing and other net revenues was primarily due to decreased margins and volumes of third-party marketing that utilized pipeline capacity, less volatility in seasonal price spreads and decreased basis differentials which in 2009 had a positive impact on the Company. This decrease was partially offset by an increase in NGL processing net revenues primarily due to an increase in average NGL sales price.

Total operating revenues increased by $115.3 million, or 25%, primarily as a result of increased marketed volumes due to higher Marcellus Shale activity and higher gathered volumes. Total purchased gas costs also increased as a result of higher Marcellus Shale activity.

Operating expenses totaled $217.6 million for 2010 compared to $195.6 million for 2009. The increase in operating expenses was primarily due to increases of $12.4 million in O&M and $8.6 million in DD&A. The increase in O&M is primarily due to higher electricity, labor, and non-income taxes associated with the growth of the business as well as a $2.6 million loss on compressor decommissioning at the Kentucky Hydrocarbon processing facility. The increase in DD&A was primarily due to the increased investment in gathering and transmission infrastructure.

Equity in earnings of nonconsolidated investments totaled $9.5 million for 2010 compared to $6.4 million for 2009. This increase is related to equity earnings recorded for EQT Midstream s investment in Nora Gathering, LLC. The higher net income was driven by increases in the average gathering fee and gathered volumes partially offset by increased operating expenses for the Nora operations in 2010.

Fiscal Year Ended December 31, 2009 vs. December 31, 2008

EQT Midstream s operating income totaled $154.2 million for 2009 compared to $119.9 million for 2008. The $34.3 million increase in operating income was primarily the result of increased gathering volumes and rates and increased Big Sandy Pipeline activity, partially offset by increased operating expenses.

Total net operating revenues were $349.8 million for 2009 compared to $287.5 million for 2008. The $62.3 million increase in total net operating revenues was due to a $25.4 million increase in gathering net operating revenues, a $25.2 million increase in transmission net operating revenues, and an $11.7 million increase in storage, marketing and other net operating revenues.

Gathering net operating revenues increased due to an 11% increase in gathered volumes as well as a 6% increase in the average gathering fee. This increase was driven by more volumes gathered for EQT Production, as well as increased third-party customer volume due to increased available capacity with the Big Sandy Pipeline being operational for a full year in 2009.

Transmission net revenues in 2009 increased from the prior year primarily due to increased capacity from the Big Sandy Pipeline, which came on-line in the second quarter of 2008.

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The increase in storage, marketing and other net revenues was primarily due to increased third-party marketing that utilized Big Sandy Pipeline capacity as well as increased margins on third-party NGLs sold.

Total operating revenues decreased by $131.6 million, or 22%, primarily as a result of lower sales prices on decreased commercial activity related to contractual transmission and storage assets partially offset by an increase in gathering volumes and rates and increased transmission revenues from the Big Sandy Pipeline. Total purchased gas costs decreased 63% as a result of lower gas costs on decreased commercial activity related to contractual transmission and storage assets.

Operating expenses totaled $195.6 million for 2009 compared to $167.6 million for 2008. The increase in operating expenses was primarily due to increases of $11.6 million in O&M and $18.5 million in DD&A, offset by a decrease of $2.1 million in SG&A. The increase in O&M resulted mainly from higher electricity, labor, non-income taxes and compressor maintenance expenses for the gathering business due to new compressors and processing facilities put in operation in the second half of 2008, partially offset by a decrease of $9.5 million relating to pension and other post-retirement benefit charges recorded in 2008. The increase in DD&A was primarily due to the increased investment in infrastructure during 2008 and 2009.

Other income represents allowance for equity funds used during construction. The $4.3 million decrease from 2008 to 2009 was primarily caused by AFUDC recorded on the construction of the Big Sandy Pipeline in 2008. AFUDC was no longer recorded once Big Sandy was placed into service in the second quarter of 2008.

Equity in earnings of nonconsolidated investments totaled $6.4 million for 2009 compared to $5.1 million for 2008. This increase is related to equity earnings recorded for EQT Midstream s investment in Nora Gathering, LLC. Earnings increased in 2009 as a result of higher net income for Nora Gathering, LLC in 2009 compared to 2008. The higher net income was driven by increases in the average gathering fee and gathered volumes partially offset by increased operating expenses for the Nora operations in 2009.

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Distribution

Results of Operations

	Years Ended December 31,				
	2010	2009	% change 2010 - 2009	2008	% change 2009 - 2008
OPERATIONAL DATA					
Heating degree days (30 year average = 5,829)	5,516	5,474	0.8	5,622	(2.6)
Residential sales and transportation volume (MMcf)	23,132	23,098	0.1	23,824	(3.0)
Commercial and industrial volume (MMcf)	27,124	30,521	(11.1)	27,503	11.0
Total throughput (MMcf)	50,256	53,619	(6.3)	51,327	4.5
Net operating revenues (thousands):					
Residential	$ 117,418	$ 111,007	5.8	$ 105,059	5.7
Commercial & industrial	48,614	47,432	2.5	46,394	2.2
Off-system and energy services	21,365	21,545	(0.8)	19,415	11.0
Total net operating revenues	187,397	179,984	4.1	170,868	5.3
Capital expenditures (thousands)	$ 36,619	$ 33,707	8.6	$ 45,770	(26.4)
FINANCIAL DATA (thousands)					
Total operating revenues	$ 474,143	$ 560,283	(15.4)	$ 698,385	(19.8)
Purchased gas costs	286,746	380,299	(24.6)	527,517	(27.9)
Net operating revenues	187,397	179,984	4.1	170,868	5.3
Operating expenses:					
O & M	44,047	43,663	0.9	44,161	(1.1)
SG&A	35,994	35,028	2.8	44,793	(21.8)
DD&A	24,174	22,375	8.0	22,055	1.5
Total operating expenses	104,215	101,066	3.1	111,009	(9.0)
Operating income	$ 83,182	$ 78,918	5.4	$ 59,859	31.8

Fiscal Year Ended December 31, 2010 vs. December 31, 2009

Distribution s operating income totaled $83.2 million for 2010 compared to $78.9 million for 2009. The increase in operating income was primarily due to an increase in base rates which was partially offset by higher operating expenses.

Net operating revenues were $187.4 million for 2010 compared to $180.0 million for 2009. The $7.4 million increase in net operating revenues was primarily the result of an increase in residential net operating revenues. Net operating revenues from residential customers increased $6.4 million as a result of the approval of the Company s Pennsylvania base rate increase in late February 2009 as well as the approval of the Company s West Virginia base rate increase in August 2010. Commercial and industrial net revenues increased $1.2 million due to higher base rates and an increase in performance-based revenues, partially offset by a decrease in usage by one industrial customer. High volume sales to this industrial customer had low unit margins and the decrease in sales did not significantly impact total net operating revenues. Off-system and energy services net operating revenues decreased due to lower margins in asset optimization activities, partially offset by increased gathering revenue as a result of higher rates. A decrease in the commodity component of residential tariff rates and a decrease in gas costs associated with asset optimization transactions resulted in a decrease in both total operating revenues and purchased gas costs.

Operating expenses totaled $104.2 million for 2010 compared to $101.1 million for 2009. The $3.1 million increase in operating expenses was primarily the result of higher bad debt and depreciation and amortization expense. The increase in bad debt expense from 2009 to 2010 was primarily the result of a favorable one-time adjustment in the allowance for uncollectible accounts in 2009 due to the recovery of CAP costs associated with the approval of the Pennsylvania rate case settlement. These increases were partially offset by an increase in accruals for certain non-income tax reserves in 2009 and a decrease in incentive compensation costs in 2010. The increase in DD&A expense was primarily the result of increased capital expenditures.

Fiscal Year Ended December 31, 2009 vs. December 31, 2008

Distribution s operating income totaled $78.9 million for 2009 compared to $59.9 million for 2008. The increase in operating income was primarily due to an increase in base rates and lower operating expenses.

Net operating revenues were $180.0 million for 2009 compared to $170.9 million for 2008. The $9.1 million increase in net operating revenues was primarily the result of the approval of the Company s base rate increase in 2009. Net revenues from residential customers increased $5.9 million as a result of an increase in base rates which was partially offset by the absence of a 2008 non-recurring increase in CAP activities, as well as customer conservation and slightly warmer weather. Off-system and energy services net operating revenues increased $2.1 million due to higher revenues from gathering activities resulting primarily from increased rates. Commercial and industrial net revenues increased $1.0 million due to higher base rates and an increase in usage by one industrial customer, partially offset by lower performance-based revenues. The high volume sales from the industrial customer have low unit margins and did not significantly impact total net operating revenues. A decrease in gas costs associated with asset optimization transactions and a decrease in the commodity component of residential tariff rates resulted in a decrease in both total operating revenues and purchased gas costs.

Operating expenses totaled $101.1 million for 2009 compared to $111.0 million for 2008. The $9.9 million decrease in operating expenses was primarily the result of lower bad debt, general overhead and labor and fringe benefit expenses in 2009 and the absence of the holding company reorganization costs that were incurred in 2008. The reduction in bad debt expense from 2008 to 2009 was the result of favorable adjustments in the allowance for uncollectible accounts in 2009 due to increased customer participation in programs assisting low-income customers in paying their bills, the recovery of CAP costs associated with the approval of the rate case settlement and a decrease in the commodity component of residential tariff rates. These decreases were partially offset by an increase in accruals for certain non-income tax reserves and an increase in incentive compensation costs.

Other Income Statement Items

	Years Ended December 31,		
	2010	2009	2008
		(Thousands)	

Other than temporary impairment on available-for-sale securities	$	$	$ (7,835)
Gain on sale of available-for-sale securities, net	2,079		
Other income	1,147	2,076	6,233

As discussed in Note 9 to the Company s Consolidated Financial Statements, the Company s available-for-sale investments consist of equity and bond funds intended to fund plugging and abandonment and other liabilities for which the Company self-insures. At December 31, 2008, these investments had a fair market value which was $7.8 million below cost. The Company analyzed the decline in these investments based on the extent and duration of the impairment and the nature of the underlying assets. Although the Company holds these investments to fund long-term liabilities, based on the extent and duration of the impairment, combined with then current market conditions, the Company concluded that the decline was other-than-temporary. As such, the Company recognized a $7.8 million impairment in earnings in 2008.

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During 2010, the Company sold available-for-sale securities for $12.3 million which resulted in gross realized gains of $2.1 million, $1.4 million of which was reclassified from accumulated other comprehensive income (OCI).

In 2010, 2009 and 2008, other income primarily relates to contributions in aid of construction and the equity portion of AFUDC on various projects. The decrease in other income from 2008 to 2009 reflects the completion of the construction of the Big Sandy Pipeline in the second quarter of 2008.

Interest Expense

	Years Ended December 31,		
	2010	**2009**	**2008**
		(Thousands)	
Interest expense	$128,157	$111,779	$58,394

Interest expense increased by $16.4 million from 2009 to 2010 primarily due to the full year of expense incurred on the $700 million of 8.125% notes issued in May 2009. This increase was partially offset by a $4.4 million increase in capitalized interest primarily due to the capitalization of interest on Marcellus Shale well development beginning in 2010 reflecting the longer time to flow gas and increased investment associated with the multi-well pads.

Interest expense increased by $53.4 million from 2008 to 2009 primarily due to the Company s continued investment in drilling and midstream infrastructure during 2009. This investment was partially funded by the issuance of $700 million of 8.125% notes in May 2009. The interest expense associated with these notes was partially offset by a 2.8% decrease in the average short-term interest rate during 2009.

Weighted average annual interest rates on the Company s long-term debt were 6.8%, 6.5% and 6.1% for 2010, 2009 and 2008, respectively. Weighted average annual interest rates on the Company s short-term debt were 0.7%, 0.7% and 3.5% for 2010, 2009 and 2008, respectively.

Income Taxes

	Years Ended December 31,		
	2010	**2009**	**2008**
		(Thousands)	
Income Taxes	$127,520	$96,668	$154,920

Income tax expense increased by $30.9 million from 2009 to 2010 as a result of higher pre-tax income partially offset by a lower effective tax rate. During 2010, the Company s effective income tax rate decreased from 38.1% to 35.9%. The higher tax rate in 2009 is primarily the result of the impact in 2009 of certain nondeductible expenses and the loss of certain prior year deductions as a result of carrying 2009 losses back to receive a cash refund of taxes paid. These higher rates in 2009 were partially mitigated by a regulatory asset recorded to recover deferred taxes caused by an accounting method change that deducts as repairs certain costs capitalized for financial accounting purposes in 2009. Rates were also lower in 2010 due to the reduction of the reserve for uncertain tax positions due to the expiration of applicable statutes of limitation in 2010.

Income tax expense decreased by $58.3 million from 2008 to 2009 despite a higher effective tax rate as a result of lower pre-tax income. During 2009, the Company s effective income tax rate increased from 37.7% to 38.1%. The higher tax rate in 2009 is primarily the result of nondeductible compensation expense partially offset by a regulatory asset recorded to recover deferred taxes caused by an accounting method change that deducts as repairs certain costs capitalized for financial accounting purposes. The Company recorded a tax benefit in 2008 for a change in the West Virginia state tax law that primarily provides for a reduction in future corporate income tax rates which was partially offset by additional tax expense recorded as a result of the completion of the IRS audit through the 2005 tax year.

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The Company was in an overall federal tax net operating loss position for 2008, 2009 and 2010 and expects to pay minimal federal income taxes for the next few years as the Company s drilling program in Appalachia continues to generate intangible drilling cost deductions, unless tax laws change or the Company incurs an unexpected taxable gain from a transaction. For federal income tax purposes, the Company currently deducts approximately 80% of drilling costs as intangible drilling costs (IDC) in the year incurred. The primary reasons for the Company s net operating loss 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. In addition, tax legislation was passed in 2008, 2009 and 2010 that allowed companies to deduct 50% of the cost of qualified assets placed in service for those years. Under the Tax Relief, Unemployment Insurance Reauthorization, and Job Create Act of 2010 (2010 Tax Relief Act), companies may deduct 100% of the cost of qualified assets placed in service after September 8, 2010 and before January 1, 2012.

See Note 7 to the Consolidated Financial Statements for further discussion of the Company s income taxes.

Outlook

The Company is committed to profitably expanding its production and developing its reserves through cost-effective, technologically-advanced horizontal drilling in its existing plays. A substantial portion of the Company s drilling efforts in 2011 are expected to be focused on drilling horizontal wells in shale formations in Pennsylvania, West Virginia and Kentucky. The Company expects natural gas sales volume growth of 30% in 2011. Gathering, transmission and marketed volumes are also expected to increase as the Company expands its infrastructure to support its expected growth of produced gas sales. Specifically, in 2011 the Company will focus on:

- **Marcellus Shale.** The Marcellus Shale is the Company s fastest growing and most profitable play. The Company expects to access significantly more reserves for less than a proportional amount of development costs through extended lateral drilling and experimenting with new hydraulic fracturing techniques. The Company also plans to spend $12.0 million on seismic data to determine optimal placement for future Marcellus Shale wells.

To support the Marcellus Shale drilling growth, the Company plans to add 130 MMcfe per day of incremental gathering capacity. The Company will also strive to optimize its contractual capacity and storage assets, which include 350,000 Dth per day of capacity in TGP s 300-Line expansion project, which is expected to turn in line late in 2011.

Also, the Company expects to continue to invest in its Equitrans Marcellus expansion project. The project is underway and, given its significant scope, is progressing in stages. Equitrans placed Phase 1 into service on October 1, 2010. Equitrans filed the certificate application for Phase 2 with the FERC on January 27, 2011, anticipates obtaining final approval in the summer of 2011 and expects to have Phase 2 in service by the end of 2012. Over the course of the next two years, the Equitrans Marcellus expansion project will add approximately 550 MMcfe per day of incremental transmission capacity. Equitrans entered into firm capacity agreements of approximately 530 MMcfe per day with both third-parties and affiliates in support of the Marcellus expansion project.

Finally, to continue the accelerated development of the Marcellus Shale play, the Company is also considering partnering with third parties, as well as other arrangements, including a potential sale of the Big Sandy Pipeline, to monetize the value of mature assets to redeploy into higher-growth Marcellus Shale development.

- **Huron Shale.** The Company plans to continue developing its highly successful horizontal drilling program in the Huron Shale play, where it drills horizontal wells and, where possible, extends the lateral length. As many of the Huron wells produce wet gas (with significant NGL content), and NGLs receive higher prices per Btu than natural gas, the Company expects to continue benefiting from the improved economics over an equivalent dry gas well. The Company has significant midstream capacity in the Huron play and is concentrating its drilling near this capacity to further enhance the return on investment.

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Capital Resources and Liquidity

Overview

The Company s primary sources of cash for 2010 were cash flows from operating activities and proceeds from an offering of common stock. The Company s primary uses of cash for 2010 were for capital expenditures and interest and dividend payments.

Operating Activities

The Company s net cash provided by operating activities during 2010 was $789.7 million compared to $725.7 million for the same period of 2009. The increase in cash flows provided by operating activities is primarily attributable to higher earnings resulting from increased production volumes and higher NGL prices partially offset by lower realized natural gas prices. In addition, EQT received income tax refunds of $129.5 million in 2010 primarily relating to the 2009 net operating loss carryback.

The Company s net cash provided by operating activities during 2009 was $725.7 million compared to $509.2 million for the same period of 2008. EQT received an income tax refund of $115.2 million in 2009 relating to the 2008 net operating loss carryback. The remaining increase in cash flows provided by operating activities is primarily the result of lower inventory, accounts receivable, unbilled revenues and margin deposits due to lower average natural gas commodity prices in 2009 compared to 2008. These were partially offset by a corresponding decrease in accounts payable at December 31, 2009 as compared to December 31, 2008.

Investing Activities

Cash flows used in investing activities totaled $1,239.4 million for 2010 as compared to $985.5 million for 2009. The increase in cash flows used in investing activities was primarily attributable to an increase in capital expenditures to $1,246.9 million in 2010 from $963.9 million in 2009. See discussion of capital expenditures below. This increase was partially offset by proceeds from the sale of available for sale securities and reduced capital contributions to Nora Gathering, LLC.

Cash flows used in investing activities totaled $985.5 million for 2009 as compared to $1,376.0 million for 2008. The decrease in cash flows used in investing activities was primarily attributable to the following:

- a decrease in capital expenditures to $963.9 million in 2009 from $1,344.0 million in 2008 due to the completion of the construction of the Big Sandy Pipeline and Kentucky Hydrocarbon processing plant upgrade in 2008;

- a decrease in capital contributions to Nora Gathering, LLC for use in midstream infrastructure projects to $6.4 million in 2009 from $29.0 million in 2008;

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Capital Expenditures

	2011 Plan		2010 Actual		2009 Actual		2008 Actual	
Well development (primarily drilling)	$	691 million	$	888 million	$	686 million	$	615 million
Undeveloped property acquisitions	$		$	358 million	$	31 million	$	86 million
Midstream infrastructure	$	244 million	$	193 million	$	201 million	$	594 million
Distribution infrastructure and other corporate items	$	35 million	$	39 million	$	46 million	$	49 million
Total	$	970 million	$	1,478 million	$	964 million	$	1,344 million
Less: non-cash	$		$	231 million	$		$	
Total cash capital expenditures	$	970 million	$	1,247 million	$	964 million	$	1,344 million

Capital expenditures for drilling and development totaled $888 million and $686 million during 2010 and 2009, respectively. The Company drilled 489 gross wells (395 net wells) in 2010, including 90 horizontal Marcellus Shale wells with approximately 300,000 feet of pay and 236 horizontal Huron wells with approximately 1.0 million feet of pay, compared to 702 gross wells (536 net wells) in 2009, including 46 horizontal Marcellus Shale wells with approximately 100,000 feet of pay and 356 horizontal Huron wells with approximately 1.0 million feet of pay. Capital expenditures for 2010 also included $358 million for undeveloped property acquisitions, primarily within the Marcellus Shale play. Capital expenditures for 2009 included $31 million for undeveloped property acquisitions.

During 2010, the Company acquired approximately 58,000 net acres in the Marcellus Shale from a group of private operators and landowners. The acreage is located primarily in Cameron, Clearfield, Elk and Jefferson counties in Pennsylvania. The purchase included a 200 mile gathering system, with associated rights of way, and approximately 100 producing vertical wells. The Company paid $282.2 million for these assets, $230.7 million in EQT stock and $51.5 million in cash. Following the closing of the acquisition, the Company holds approximately 520,000 net acres in the high pressure Marcellus Shale fairway.

Capital expenditures for the midstream operations totaled $193 million for 2010. During the year, EQT Midstream turned in-line 132 miles of pipeline and 21,000 horse power of compression primarily within the Marcellus and Huron Shale plays. During 2009, midstream capital expenditures were $201 million. EQT Midstream turned in-line 274 miles of pipeline and 21,850 horse power of compression primarily within the Huron play in that year.

Capital expenditures at Distribution totaled $37 million and $34 million during 2010 and 2009, respectively, principally for pipeline replacement and metering. The increase in capital expenditures was due to increased gathering-related infrastructure spending in 2010 as compared to 2009.

The Company is committed to profitably expanding its production and reserves through horizontal drilling, exploiting additional reserve potential through key emerging development plays and expanding its infrastructure in the Appalachian Basin through, among other projects, the Equitrans Marcellus expansion project. Capital expenditures for 2011 are expected to be concentrated on drilling in areas that already benefit from the Company s substantial Appalachian midstream infrastructure. The Company s planned 2011 capital expenditures are designed to achieve annual gas sales volume growth of 30% in 2011, without requiring access to the capital markets. The Company believes it has sufficient liquidity to finance its planned capital expenditures with cash generated from operating activities as well as the proceeds from the sale of the Kentucky natural gas processing facility.

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Financing Activities

Cash flows provided by financing activities totaled $449.7 million for 2010 as compared to $259.8 million for 2009 as a result of the proceeds from the 2010 equity offering exceeding the proceeds of the 2009 debt offering, net of repayment of short-term loans. On March 16, 2010, the Company completed a common stock offering of 12,500,000 shares. The underwriters in this transaction also exercised their over-allotment option to purchase 225,000 additional shares of the Company s Common Stock on April 14, 2010. The Company is using the net proceeds of $537.2 million from the offering to accelerate development of its Marcellus and Huron Shale plays.

Cash flows provided by financing activities totaled $259.8 million for 2009 as compared to $785.1 million for 2008. During 2009, the Company received $700 million from the public sale of 8.125% Senior Notes due June 1, 2019. By comparison, during 2008, the Company received $560.7 million from the public sale of 8.625 million shares of common stock and $500 million from the public sale of 6.50% Senior Notes due April 1, 2018. A portion of the 2009 and 2008 debt offerings were used to repay short-term borrowings under the Company s revolving credit facility during the periods. The Company repaid $314.9 million in short-term borrowing during 2009 and $130.1 million in short-term borrowings during the same period in 2008. The Company also repaid $4.3 million in long-term debt during 2009.

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 and the amount and type of derivative commodity instruments executed.

The Company has a $1.5 billion revolving credit facility that matures on December 8, 2014. The facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes, including support of any commercial paper program maintained by the Company from time to time. The credit facility is underwritten by a syndicate of 20 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. The Company s large syndicate group and relatively low percentage of participation by each lender is expected to limit the Company s exposure if problems or consolidation occur in the banking industry.

As of December 31, 2010, the Company had outstanding under the revolving credit facility loans of $53.7 million, and an irrevocable standby letter of credit of $23.5 million. The weighted average interest rate for short-term loans outstanding as of December 31, 2010 was 1.8% and the maximum amount of outstanding short-term loans at any time during 2010 was $139.7 million. The average daily balance of short-term loans outstanding over the course of the year was approximately $24.9 million and the weighted average interest rate on the Company s short-term borrowings was 0.7% for 2010. Under the terms of the revolving credit facility, the Company may obtain loans, which are 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 determined on the basis of the Company s then current credit rating. Fixed period Eurodollar rate loans bear interest on a Eurodollar rate plus a margin determined on the basis of the Company s then current credit rating.

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

Security Ratings and Financing Triggers

The table below reflects the credit ratings for the outstanding debt instruments of the Company at December 31, 2010. 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.

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Rating Service	Unsecured Medium-Term Notes	Commercial Paper
Moody s Investors Service	Baa1	P-2
Standard & Poor s Ratings Services	BBB	A-3
Fitch Ratings Service	BBB+	F2

On September 30, 2010 Moody s Investors Services (Moody s) reaffirmed its ratings on EQT. The outlook is negative. Moody s stated that the ratings reflect the diversification and vertical integration among its three business segments as well as the Baa stand alone quality of both its E&P and LDC operations.

On September 20, 2010, Standard & Poor s Ratings Services (S&P) reaffirmed its ratings on EQT. The outlook is negative. S&P stated that the ratings and outlook reflect the Company s competitive operating cost structure in its exploration and production (E&P) segment, long reserve life and the Company s aggressive spending in its more volatile E&P and midstream businesses.

On March 26, 2010, Fitch affirmed its ratings on EQT stating that the ratings are supported by the strong performance of its upstream segment, the relatively predictable cash flows from its midstream and distribution segments, a significant use of equity to help finance its growth strategy, and management s continued maintenance of a strong liquidity position.

The Company s credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization and each rating should be evaluated independently of any other rating. The Company cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a credit rating agency if, in its judgment, circumstances so warrant. If the credit rating agencies downgrade the Company s ratings, particularly below investment grade, the Company s access to the capital markets may be limited, borrowing costs and margin deposits on derivative contracts would increase, counterparties may request additional assurances and the potential pool of investors and funding sources may decrease. The required margin is subject to significant change as a result of other factors besides credit rating such as gas prices and credit thresholds set forth in agreements between the hedging counterparties and the Company.

The Company s debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. The most significant default events include maintaining covenants with respect to maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company s current credit facility s financial covenants require a total debt-to-total capitalization ratio of no greater than 65%. The calculation of this ratio excludes the effects of accumulated other comprehensive income (loss). As of December 31, 2010, the Company was in compliance with all existing debt provisions and covenants.

Commodity Risk Management

The Company s overall objective in its hedging program is to protect cash flow from undue exposure to the risk of changing commodity prices. The Company s risk management program includes the use of exchange-traded natural gas futures contracts and options and OTC natural gas swap agreements and options (collectively, derivative commodity instruments) to hedge exposures to fluctuations in natural gas prices and for trading purposes. The derivative commodity instruments currently utilized by the Company are primarily fixed price swaps, collars and options.

The approximate volumes and prices of the Company s total hedge position for 2011 through 2013 production are:

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	2011		2012		2013	
Swaps						
Total Volume (Bcf)		56		24		
Average Price per Mcf (NYMEX)*	$	4.86	$	5.27	$	
Puts						
Total Volume (Bcf)		3				
Average Floor Price per Mcf (NYMEX)*	$	7.35	$		$	
Collars						
Total Volume (Bcf)		21		21		15
Average Floor Price per Mcf (NYMEX)*	$	6.53	$	6.51	$	6.12
Average Cap Price per Mcf (NYMEX)*	$	11.91	$	11.83	$	11.80

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

In 2008, the Company effectively settled certain derivative commodity swaps scheduled to mature during the period 2010 through 2013 by de-designating the swaps and entering into directly counteractive swaps. In 2009, the Company also terminated certain collars scheduled to mature during the period 2010 through 2012. As of the dates of these transactions, the Company had recorded a loss, net of tax, in accumulated other comprehensive income (loss) of approximately $12 million ($21 million pre-tax) for the swaps and a gain, net of tax, in accumulated other comprehensive income (loss) of approximately $5 million ($8 million pre-tax) for the collars. The net loss recorded in other comprehensive income (loss) from these transactions will be recognized in operating revenues in the Statements of Consolidated Income, and included in the average well-head sales price, when the underlying physical transactions occur. As a result, the Company will recognize reduced operating revenues of approximately $5.4 million, $0.6 million and $2.5 million in 2011, 2012 and 2013 respectively.

See the Quantitative and Qualitative Disclosures About Market Risk, in Item 7A and Note 3 to the Company s Consolidated Financial Statements for further discussion.

Other Items

Off-Balance Sheet Arrangements

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that once the energy-efficiency construction was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a period of years. The undiscounted maximum aggregate payments that may be due related to these guarantees is approximately $234 million as of December 31, 2010, extending at a decreasing amount for approximately 19 years. In addition, the Company agreed to maintain in place certain outstanding payment and performance bonds, letters of credit and other guarantee obligations supporting NORESCO s obligations under certain customer contracts, existing leases and other items with an undiscounted maximum exposure to the Company as of December 31, 2010 of approximately $40 million, of which approximately $34 million relates to bonds that were to have been terminated as of December 31, 2010 for work completed under the underlying contracts. The Company is working with NORESCO to resolve any open matters with respect to these bonds.

In exchange for the Company s agreement to maintain these guarantee obligations, the purchaser of the NORESCO business and NORESCO agreed, among other things, that NORESCO would fully perform its obligations under each underlying agreement and agreed to reimburse the Company for any loss under the guarantee obligations, provided that the purchaser s reimbursement obligation will not exceed $6 million in the aggregate and will expire on November 18, 2014. In 2008, the original purchaser of NORESCO sold its interest in NORESCO and transferred its obligations to a third-party. In connection with that event, the new owner delivered to the Company a $1 million letter of credit supporting its obligations.

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

The Company has a non-equity interest in a variable interest entity, Appalachian NPI, LLC (ANPI), in which EQT was not deemed to be the primary beneficiary because EQT does not have the power to direct the activities that most significantly impact ANPI s economic performance. Thus, ANPI is not consolidated within the Company s Consolidated Financial Statements. As of December 31, 2010, ANPI had $143.8 million of total assets and $86.1 million of total liabilities (including $66.3 million of long-term debt, including current maturities), excluding minority interest. ANPI is financed primarily through cash provided by operating activities.

The Company provides a liquidity reserve guarantee to ANPI, which is subject to certain restrictions and limitations that limit the amount of the guarantee to the calculated present value of the project s future cash flows from the preceding year-end until the termination date of the agreement. This liquidity reserve guarantee is equal to the fair market value of the assets purchased by ANPI. The Company receives a market-based fee for the issuance and continuation of the reserve guarantee. As of December 31, 2010, the maximum amount of future payments the Company could be required to make under the liquidity reserve guarantee is estimated to be approximately $31 million. The Company has not recorded a liability for this guarantee. The terms of the ANPI liquidity reserve guarantee require the Company to provide a letter of credit in favor of ANPI as security for the Company s obligations. The amount of this letter of credit requirement at December 31, 2010 was approximately $23.5 million and is expected to decline over time under the terms of the liquidity reserve guarantee.

The Company has entered into an agreement with Appalachian Natural Gas Trust (ANGT) to provide gathering and operating services to deliver ANGT s gas to market. In addition, the Company receives a marketing fee for the sale of gas based on the net revenue for gas delivered. The revenue earned from these fees totaled approximately $15.6 million, $15.7 million and $15.9 million for 2010, 2009 and 2008, respectively.

See Note 19 to the Consolidated Financial Statements for further discussion of the Company s guarantees.

Rate Regulation

The Company s distribution operations, transmission and storage operations and a portion of its gathering operations are subject to various forms of regulation as previously discussed. As described in Notes 1 and 10 to the Consolidated Financial Statements, regulatory accounting allows the Company to defer expenses and income as regulatory assets and liabilities which reflect future collections or payments through the regulatory process. The Company believes that it will continue to be subject to rate regulation that will provide for the recovery of the deferred costs.

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Schedule of Contractual Obligations

The following table details the undiscounted future projected payments associated with the Company s contractual obligations as of December 31, 2010.

	Total	2011	2012-2013	2014-2015	2016+
			(Thousands)		
Purchase obligations	$1,608,554	$ 66,553	$ 293,334	$ 223,637	$ 1,025,030
Long-term debt	1,949,200	6,000	210,000	165,000	1,568,200
Interest payments	1,034,866	133,296	253,407	241,017	407,146
Operating leases	171,747	28,390	45,204	23,427	74,726
Pension and other post-retirement benefits	174,263	10,722	20,315	19,183	124,043
Other liabilities	38,173	38,173			
Total contractual obligations	$4,976,803	$ 283,134	$ 822,260	$ 672,264	$ 3,199,145

Purchase obligations primarily are commitments for demand charges under existing long-term contracts and binding precedent agreements with various pipelines. Approximately $17.0 million and $13.7 million of these obligations payable in 2011 and 2012, respectively, are believed to be recoverable in customer rates.

Operating leases are primarily entered into for various office locations and warehouse buildings, as well as dedicated drilling rigs in support of the Company s drilling program. The obligations for the Company s various office locations and warehouse buildings totaled approximately $119.0 million as of December 31, 2010. The Company has subleased some of these facilities. Sublease payments to the Company total $32.4 million and are not netted from the amounts presented in the above table. The Company has agreements with Savanna Drilling, LLC, Highlands Drilling, LLC, Patterson, Helmerich & Payne International Drilling and other drilling contractors to provide drilling equipment and services to the Company. These obligations totaled approximately $52.8 million as of December 31, 2010.

The other liabilities line represents commitments for total estimated payouts for the 2007 Supply Long-Term Incentive Program and the 2008 Executive Performance Incentive Program. See section titled Critical Accounting Policies Involving Significant Estimates and Note 16 to the Consolidated Financial Statements for further discussion regarding factors that affect the ultimate amount of the payout of these obligations. Effective 2011, the Company adopted the 2011 Value Driver Award program. The Company may adopt other plans in the future. The contractual obligations do not include any payments under the 2011 Value Driver Award program or any potential future plans.

As discussed in Note 7 to the Consolidated Financial Statements, the Company had a total liability for the reserve for unrecognized tax benefits at December 31, 2010 of $41.5 million. The Company is currently unable to make reasonably reliable estimates of the period of cash settlement of these potential liabilities with taxing authorities; therefore, this amount has been excluded from the schedule of contractual obligations presented above.

Contingent Liabilities and Commitments

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company has established reserves for pending litigation, which it believes are adequate, 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.

See Note 18 to the Consolidated Financial Statements for further discussion of the Company s contingent liabilities and commitments.

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Critical Accounting Policies Involving Significant Estimates

The Company s significant accounting policies are described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Form 10-K. The discussion and analysis of the Consolidated Financial Statements and results of operations are based upon EQT s Consolidated Financial Statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these Consolidated Financial Statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. The following critical accounting policies, which were reviewed by the Company s Audit Committee, relate to the Company s more significant judgments and estimates used in the preparation of its Consolidated Financial Statements. There can be no assurance that actual results will not differ from those estimates.

Accounting for Oil and Gas Producing Activities: The Company uses the successful efforts method of accounting for its oil and gas production activities. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the property has proved reserves. If an exploratory well does not result in proved reserves, the costs of drilling the well are charged to expense and included within cash flows from investing activities in the Consolidated Statements of Cash Flows. The costs of development wells are capitalized whether productive or nonproductive. Depletion is calculated based on the annual actual production multiplied by the depletion rate per unit. The depletion rate is derived by dividing the total costs capitalized over the number of units expected to be produced over the life of the reserves.

The carrying values of the Company s proved oil and gas properties are reviewed for indications of impairment whenever events or circumstances indicate that the remaining carrying value may not be recoverable. In order to determine whether impairment has occurred, the Company estimates the expected future cash flows (on an undiscounted basis) from its proved oil and gas properties and compares those future cash flows to the carrying values of the applicable properties. The estimated future cash flows used to test properties for recoverability are based on proved reserves, utilizing assumptions about the use of the asset, market prices for oil and gas and future operating costs. Proved oil and gas properties that have carrying amounts in excess of estimated future cash flows would be deemed unrecoverable. Those properties would be written down to fair value, which would be estimated by discounting the estimated future cash flows using discount rate assumptions that marketplace participants would use in their estimates of fair value.

Capitalized costs of unproved properties are evaluated at least annually for recoverability on an aggregated prospect basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period in which that determination is made. Unproved properties had a net book value of $445.9 million, $105.9 million and $81.9 million in 2010, 2009 and 2008, respectively.

The Company believes that the accounting estimate related to the accounting for oil and gas producing activities is a critical accounting estimate because the Company must assess the remaining recoverable proved reserves, a process which can be significantly impacted by management s expectations regarding proved undeveloped drilling locations and its future development plans. Should the Company begin to develop new producing regions or begin more significant exploration activities, future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions.

Oil and Gas Reserves: The Company adopted the SEC rule, Modernization of Oil and Gas Reporting, as of December 31, 2009. Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10, are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

The Company s estimates of proved reserves are made and reassessed annually using geological and reservoir data as well as production performance data. Reserve estimates are prepared and updated by the Company s

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engineers and reviewed by the Company s independent engineers. Revisions may result from changes in, among other things, reservoir performance, development plans, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits sooner. A material change in the estimated volumes of reserves could have an impact on the depletion rate calculation and the financial statements.

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

The Company believes that the accounting estimate related to oil and gas reserves is a critical accounting estimate because the Company must periodically reevaluate proved reserves along with estimates of future production and the estimated timing of development expenditures. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions.

Income Taxes: The Company recognizes deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the Company s Consolidated Financial Statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial reporting and tax bases of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

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

The Company estimates the amount of financial statement benefit to record for uncertain tax positions by first determining whether it is more likely than not that a tax position in a tax return will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If this step is satisfied, then the Company must measure the tax position. The tax position is measured at the largest amount of benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement. See Note 7 to the Company s Consolidated Financial Statements for further discussion.

The Company believes that accounting estimates related to income taxes are critical accounting estimates because the Company must assess the likelihood that deferred tax assets will be recovered from future taxable income and exercise judgment regarding the amount of financial statement benefit realizable upon ultimate settlement. To the extent the Company believes it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, a valuation allowance must be established. Significant management judgment is required in determining any valuation allowance recorded against deferred tax assets and in determining the amount of financial statement benefit to record for uncertain tax positions. The Company considers all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. In making this determination, the Company considers the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of financial statement benefit. Evidence used for the valuation allowance includes information about the Company s current financial position and results of operations for the current and preceding years, as well as all currently available information about future years, including the Company s anticipated future performance, the reversal of deferred tax assets and liabilities and tax planning strategies available to the Company. To the extent that an uncertain tax

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position or valuation allowance is established or increased or decreased during a period, the Company must include an expense or benefit within tax expense in the income statement.

Derivative Commodity Instruments: The Company enters into derivative commodity instrument contracts to mitigate exposure to commodity price risk associated with future natural gas production. The Company also enters into energy trading contracts to leverage its assets and limit its exposure to shifts in market prices. Derivative instruments are required to be recorded on the balance sheet as either an asset or a liability measured at fair value. If the derivative qualifies for cash flow hedge accounting, the change in fair value of the derivative is recognized in accumulated other comprehensive income (loss) (equity) to the extent that the hedge is effective and in the income statement to the extent it is ineffective. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. See Commodity Risk Management above, Item 7A Quantitative and Qualitative Disclosures About Market Risk and Note 3 of the Consolidated Financial Statements for additional information regarding hedging activities.

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

A substantial majority of the Company s derivative financial instruments are designated as cash flow hedges. Should these instruments fail to meet the criteria for hedge accounting or be de-designated, the subsequent changes in fair value of the instruments would be recorded in earnings, which could materially impact the results of operations. One of the requirements for hedge accounting is that a derivative instrument be highly effective at offsetting the changes in cash flows of the transaction being hedged. Effectiveness may be impacted by counterparty credit rating as it must be probable that the counterparty will perform in order for the hedge to be effective. The Company monitors counterparty credit quality by reviewing counterparty credit spreads, credit ratings, credit default swap rates and market activity.

In addition, the derivative commodity instruments used to mitigate exposure to commodity price risk associated with future natural gas production may limit the benefit the Company would receive from increases in the prices for oil and natural gas and may expose the Company to margin requirements. Given the Company s price risk management position and price volatility, the Company may be required from time to time to deposit cash with or provide letters of credit to its counterparties in order to satisfy these margin requirements.

The Company believes that the accounting estimates related to derivative commodity instruments are critical accounting estimates because the Company s financial condition and results of operations can be significantly impacted by changes in the market value of the Company s derivative instruments due to the volatility of natural gas prices, changes in the effectiveness of cash flow hedges due to changes in estimates of non-performance risk and by changes in margin requirements.

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

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

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

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

Share Based Compensation: The Company has awarded share-based compensation in connection with specific programs established under the 1999 and 2009 Long-Term Incentive Plans. The Company treats certain of its Executive Performance Incentive Programs, including the 2008 Executive Performance Incentive Program (2008 EPIP) and the 2007 Supply Long-Term Incentive Program (2007 Supply Program) as liability awards. The actual cost to be recorded for these plans will not be known until the measurement date, requiring the Company to estimate the total expense to be recognized at each reporting date. The Company reviews the assumptions for both programs on a quarterly basis and adjusts its accrual when changes in these assumptions result in a material change in the fair value of the ultimate payouts.

Approximately 70,000 units were granted under the 2008 EPIP. The payout of this program will be between zero and three times this number of units valued at the price of the Company s common stock at the end of the performance period, December 31, 2011. The payout multiple is dependent upon the level of total shareholder return relative to a predefined peer group s total shareholder return and the downward discretion of the Compensation Committee of the Board of Directors if the Company does not attain a specified revenue target. As of December 31, 2010, 265,850 awards were outstanding under the 2007 Supply Program. The awards earned were increased to the maximum of three times the initial award based upon achievement of the predetermined production sales revenue and efficiency targets. The performance period for the 2007 Supply Program ended on December 31, 2010.

Assuming no change in the current payout multiple assumptions for 2008 EPIP, a 10% increase in the Company s stock price assumption would have resulted in an increase in 2010 compensation expense under this plan of approximately $0.2 million.

Effective January 1, 2010, the Company adopted the 2010 Executive Performance Incentive Program (2010 Program) and the 2010 Stock Incentive Award (2010 SIA) program. The vesting of the units under the 2010 Program will occur upon payment after the end of the 3-year performance period. The payment will vary between zero and 300% of the number of units granted contingent upon a combination of the level of total shareholder return relative to a redefined peer group over the three-year period ending December 31, 2012 and the level of production sales revenues over the period January 1, 2010 through September 30, 2012. If earned, the 2010 Program units are expected to be distributed in Company common stock. The vesting of the awards under the 2010 SIA will occur on the third anniversary of the grant date. The number of awards granted was contingent upon adjusted 2010 earnings before interest, taxes, depreciation and amortization (EBITDA) performance as compared to plan and individual, business unit and Company value driver performance over the period January 1, 2010 through December 31, 2010. As of February 2, 2011, there were 302,355 awards outstanding under the 2010 SIA which are expected to be distributed in Company common stock.

Effective 2011, the Company adopted the 2011 Volume and Efficiency Program and the 2011 Value Driver Award program. The Company may adopt other plans in the future. The Company has not recorded an obligation under the 2011 Volume and Efficiency Program, the 2011 Value Driver Award program or any potential future plans at December 31, 2010.

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The 1999 and 2009 Long-Term Incentive Plans permit the grant of restricted stock awards and non-qualified stock options to employees of the Company. For time restricted stock awards, compensation expense, which is based on the grant date fair value is recognized in the Company s financial statements over the vesting period. The majority of the time-based restricted shares granted will vest at the end of the three-year period commencing with the date of grant. For non-qualified stock options, compensation expense is based on the grant date fair value and is recognized in the Company s financial statements over the vesting period. The Company utilizes the Black-Scholes option pricing model to measure the fair value of stock options, which includes assumptions for a risk-free interest rate, dividend yield, volatility factor and expected term. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the historical dividend yield of the Company s stock. Expected volatilities are based on historical volatility of the Company s stock. The expected term of options granted represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

The Company believes that the accounting estimates related to share-based compensation are critical accounting estimates because they are likely to change from period to period based on changes in the market price of the Company s shares, the volatility of the Company s shares, market interest rates and the various performance factors. The impact on net income of these changes can be material.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Derivative Commodity Instruments

The Company s primary market risk exposure is the volatility of future prices for natural gas and NGLs, which can affect the operating results of the Company primarily through the EQT Production and EQT Midstream segments. The Company s use of derivatives to reduce the effect of this volatility is described in Notes 1 and 3 to the Consolidated Financial Statements and under the caption Commodity Risk Management in Management s Discussion and Analysis of Financial Condition and Results of Operations (Item 7) of this Form 10-K. The Company uses non-leveraged derivative commodity instruments that are placed with major financial institutions whose credit worthiness is continually monitored. The Company also enters into energy trading contracts to leverage its assets and limit its exposure to shifts in market prices. The Company s use of these derivative financial instruments is implemented under a set of policies approved by the Company s Corporate Risk Committee and Board of Directors.

Commodity Price Risk

For the derivative commodity instruments used to hedge the Company s forecasted production, the Company sets policy limits relative to the expected production and sales levels which are exposed to price risk. For the derivative commodity instruments used to hedge forecasted natural gas purchases and sales which are exposed to price risk, the Company sets limits related to acceptable exposure levels.

The financial instruments currently utilized by the Company include futures contracts, swap agreements, collar agreements and option contracts which may require payments to or receipt of payments from counterparties based on the differential between a fixed and variable price for the commodity. The Company also considers other contractual agreements in implementing its commodity hedging strategy.

Management monitors price and production levels on a continuous basis and will make adjustments to quantities hedged as warranted. The Company s overall objective in its hedging program is to ensure an adequate level of return for the well development and infrastructure investment at EQT Production and EQT Midstream.

With respect to the derivative commodity instruments held by the Company for purposes other than trading as of December 31, 2010, the Company hedged portions of expected equity production through 2015 and portions of forecasted purchases and sales by utilizing futures contracts, swap agreements and collar agreements covering approximately 162 Bcf of natural gas. See the Commodity Risk Management in the Capital Resources and Liquidity sections of Management s Discussion and Analysis of Financial Condition and Results of Operations (Item 7) of this Form 10-K for further discussion.

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The following sensitivity analysis estimates the potential effect on fair value or future earnings from derivative commodity instruments due to a 10% increase or a 10% decrease in commodity prices. A hypothetical decrease of 10% in the market price of natural gas from the December 31, 2010 levels would increase the fair value of non-trading natural gas derivative instruments by approximately $65.0 million. A hypothetical increase of 10% in the market price of natural gas from the December 31, 2010 levels would decrease the fair value of non-trading natural gas derivative instruments by approximately $62.7 million.

The Company determined the change in the fair value of the derivative commodity instruments using a method similar to its normal determination of fair value as described in Note 1 to the Consolidated Financial Statements. The price change was then applied to the derivative commodity instruments recorded on the Company s Consolidated Balance Sheets, resulting in the change in fair value.

The above analysis of the derivative commodity instruments held by the Company for purposes other than trading does not include the offsetting impact that the same hypothetical price movement may have on the Company s physical sales of natural gas. The portfolio of derivative commodity instruments held for risk management purposes approximates the notional quantity of a portion of the expected or committed transaction volume of physical commodities with commodity price risk for the same time periods. Furthermore, the derivative commodity instrument portfolio is managed to complement the physical transaction portfolio, reducing overall risks within limits. Therefore, a change to the fair value of the portfolio of derivative commodity instruments held for risk management purposes associated with the hypothetical changes in commodity prices referenced above would be offset by the impact on the underlying hedged physical transactions, assuming the derivative commodity instruments are not closed out in advance of their expected term, the derivative commodity instruments continue to function effectively as hedges of the underlying risk and the anticipated transactions occur as expected.

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

Other Market Risks

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value. The Company believes that NYMEX-traded futures contracts have minimal credit risk because the Commodity Futures Trading Commission regulations are in place to protect exchange participants, including the Company, from any potential financial instability of the exchange members. The Company s swap, collar and option derivative instruments are primarily with financial institutions and thus are subject to events that would impact those companies individually as well as that industry as a whole.

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

Approximately 69%, or $216.4 million, of OTC derivative contracts outstanding at December 31, 2010 have a positive fair value. As of December 31, 2010, all derivative contracts outstanding are with counterparties having an S&P rating of A or above at that date.

In September 2008, the credit support provider of one counterparty (Lehman Brothers Holding, Inc.) declared bankruptcy resulting in a default under various derivative contracts with the Company. As a result, those contracts were terminated and a reserve of approximately $5 million was recorded against the entire balance due to the Company. There is no additional income statement exposure to this counterparty beyond the reserve recorded in 2008. As of December 31, 2010, the Company was not in default under any derivative contract and has no knowledge of default by any counterparty to a derivative contract. The Company made no adjustments to the fair value of derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment

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included in the Company s established fair value procedure. The Company will continue to monitor market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

The Company is also exposed to the risk of nonperformance by credit customers on physical sales of natural gas. A significant amount of revenues and related accounts receivable from EQT Production are generated from the sale of produced natural gas to certain marketers, including the Company s wholly owned marketing subsidiary EQT Energy, utility and industrial customers located mainly in the Appalachian area and a gas processor in Kentucky. Additionally, a significant amount of revenues and related accounts receivable from EQT Midstream are generated from the gathering of natural gas in Kentucky, Virginia, Pennsylvania and West Virginia.

The Company has a $1.5 billion revolving credit facility that matures on December 8, 2014. The credit facility is underwritten by a syndicate of 20 financial institutions each of which is obligated to fund its pro-rata portion of any borrowings by the Company. As of December 31, 2010, the Company had outstanding under the facility $53.7 million of loans in support of corporate activities and an irrevocable standby letter of credit of $23.5 million.

No single lender of the 20 financial institutions in the syndicate holds more than 10% of the facility. The Company s large syndicate group and relatively low percentage of participation by each lender is expected to limit the Company s exposure if problems or consolidation occur in the banking industry.

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Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

EQT Corporation

We have audited the accompanying consolidated balance sheets of EQT Corporation and Subsidiaries (formerly Equitable Resources, Inc.) as of December 31, 2010 and 2009, and the related statements of consolidated income, common stockholders equity and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of EQT Corporation and Subsidiaries (formerly Equitable Resources, Inc.) at December 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 22 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements during the year ended December 31, 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of EQT Corporation and Subsidiaries (formerly Equitable Resources, Inc.) internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2011, expressed an unqualified opinion thereon.

Pittsburgh, Pennsylvania

February 24, 2011

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

EQT Corporation

We have audited EQT Corporation and Subsidiaries (formerly Equitable Resources, Inc.) internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). EQT Corporation and Subsidiaries (formerly Equitable Resources, Inc.) management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, EQT Corporation and Subsidiaries (formerly Equitable Resources, Inc.) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of EQT Corporation and Subsidiaries (formerly Equitable Resources, Inc.) as of December 31, 2010 and 2009, and the related statements of consolidated income, common stockholders equity and cash flows for each of the three years in the period ended December 31, 2010 and our report dated February 24, 2011 expressed an unqualified opinion thereon.

Pittsburgh, Pennsylvania

February 24, 2011

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EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED INCOME

YEARS ENDED DECEMBER 31,

	2010	2009	2008
		(Thousands except per share amounts)	
Operating revenues	$ 1,322,708	$ 1,269,827	$ 1,576,488
Operating expenses:			
Purchased gas costs	201,197	319,369	645,136
Operation and maintenance	152,414	140,003	129,712
Production	67,414	62,978	79,858
Exploration	5,368	17,905	9,064
Selling, general and administrative	155,551	176,703	111,096
Depreciation, depletion and amortization	270,285	196,078	136,816
Total operating expenses	852,229	913,036	1,111,682
Operating income	470,479	356,791	464,806
Other than temporary impairment of available-for-sale securities			(7,835)
Gain on sale of available-for-sale securities, net	2,079		
Equity in earnings of nonconsolidated investments	9,672	6,509	5,714
Other income	1,147	2,076	6,233
Interest expense	128,157	111,779	58,394
Income before income taxes	355,220	253,597	410,524
Income taxes	127,520	96,668	154,920
Net income	$ 227,700	$ 156,929	$ 255,604
Earnings per share of common stock:			
Basic:			
Net income	$ 1.58	$ 1.20	$ 2.01
Diluted:			
Net income	$ 1.57	$ 1.19	$ 2.00

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

YEARS ENDED DECEMBER 31,

	2010	2009 (Thousands)	2008
Cash flows from operating activities:			
Net income	$ 227,700	$ 156,929	$ 255,604
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income taxes	153,912	234,776	245,801
Depreciation, depletion and amortization	270,285	196,078	136,816
Other than temporary impairment of available-for-sale securities			7,835
Gain on sale of available-for-sale securities, net	(2,079)		
Provision for (recoveries of) losses on accounts receivable	5,134	(1,263)	11,744
Other income	(1,147)	(2,076)	(6,233)
Equity in earnings of nonconsolidated investments	(9,672)	(6,509)	(5,714)
Restricted stock and stock option expense	14,104	6,768	6,700
Reimbursements for tenant improvements	4,053	12,212	
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues	(6,330)	66,327	(33,377)
Inventory	45,104	73,181	(4,697)
Prepaid expenses and other	126,042	11,836	(100,532)
Accounts payable	(36,853)	(107,745)	77,475
Derivative instruments, at fair value	(7,609)	56,510	(82,564)
Other current liabilities	(2,963)	33,502	(58,326)
Other items, net	10,059	(4,785)	58,625
Net cash provided by operating activities	789,740	725,741	509,157
Cash flows from investing activities:			
Capital expenditures	(1,246,932)	(963,908)	(1,343,996)
Capital contributions to Nora Gathering, LLC		(6,400)	(29,000)
Tenant improvements	(4,053)	(12,212)	
Proceeds from sale of available-for-sale securities	12,306		
Investment in available-for-sale securities	(750)	(3,000)	(3,000)
Net cash used in investing activities	(1,239,429)	(985,520)	(1,375,996)
Cash flows from financing activities:			
Dividends paid	(127,292)	(115,368)	(111,403)
Proceeds from issuance of common stock	537,206		560,739
Proceeds from issuance of long-term debt		700,000	500,000
Revolving credit facility origination fee and debt issuance costs	(10,962)	(6,874)	(6,645)
Increase (decrease) in short-term loans	48,650	(314,917)	(130,083)
Repayments and retirements of long-term debt		(4,300)	
Repayments of note payable to Nora Gathering, LLC			(29,329)
Proceeds and excess tax benefits from exercises under employee compensation plans	2,087	1,238	1,849
Net cash provided by financing activities	449,689	259,779	785,128
Net change in cash and cash equivalents			(81,711)
Cash and cash equivalents at beginning of year			81,711
Cash and cash equivalents at end of year	$	$	$
Cash paid (received) during the year for:			
Interest, net of amount capitalized	$ 127,904	$ 107,475	$ 51,234
Income taxes, net	$ (129,495)	$ (120,074)	$ (13,963)

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2010	2009
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$	$
Accounts receivable (less accumulated provision for doubtful accounts: 2010, $18,335; 2009, $16,792)	156,709	155,574
Unbilled revenues	38,361	38,300
Inventory	137,853	182,957
Derivative instruments, at fair value	225,339	163,879
Assets held for sale	207,678	
Prepaid expenses and other	62,000	154,456
Total current assets	827,940	695,166
Equity in nonconsolidated investments	191,265	181,866
Property, plant and equipment	7,689,025	6,478,486
Less: accumulated depreciation and depletion	1,778,934	1,563,755
Net property, plant and equipment	5,910,091	4,914,731
Investments, available-for-sale	28,968	36,156
Regulatory assets	100,949	99,144
Other	39,225	30,194
Total assets	$ 7,098,438	$ 5,957,257

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2010	2009
	(Thousands)	
Liabilities and Common Stockholders Equity		
Current liabilities:		
Current portion of long-term debt	$ 6,000	$
Short-term loans	53,650	5,000
Accounts payable	212,134	248,987
Derivative instruments, at fair value	106,721	132,518
Other current liabilities	218,479	226,169
Total current liabilities	596,984	612,674
Long-term debt	1,943,200	1,949,200
Deferred income taxes and investment tax credits	1,274,888	1,039,473
Unrecognized tax benefits	41,451	56,621
Pension and other post-retirement benefits	44,135	47,615
Other credits	119,084	100,644
Total liabilities	4,019,742	3,806,227
Common stockholders equity:		
Common stock, no par value, authorized 320,000 shares; shares issued: 175,684 in 2010 and 157,630 in 2009	1,723,898	952,237
Treasury stock, shares at cost: 26,531 in 2010 and 26,699 in 2009	(479,072)	(482,125)
Retained earnings	1,795,766	1,695,358
Accumulated other comprehensive income (loss)	38,104	(14,440)
Total common stockholders equity	3,078,696	2,151,030
Total liabilities and common stockholders equity	$ 7,098,438	$ 5,957,257

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

YEARS ENDED DECEMBER 31, 2010, 2009 and 2008

	Common Stock			Accumulated	
	Shares Outstanding	No Par Value	Retained Earnings	Other Comprehensive (Loss) Income	Common Stockholders Equity
			(Thousands)		
Balance, December 31, 2007	122,152	$ (102,860)	$ 1,509,596	$ (309,264)	$ 1,097,472
Comprehensive income (net of tax):					
Net income			255,604		255,604
Net change in cash flow hedges:					
Natural gas, net of tax of $155,678 (see Note 3)				257,442	257,442
Interest rate				115	115
Unrealized loss on available-for-sale securities				(3,872)	(3,872)
Pension and other post-retirement benefits liability adjustment, net of tax benefit of $8,697				(13,158)	(13,158)
Total comprehensive income					496,131
Dividends ($0.88 per share)			(111,403)		(111,403)
Stock-based compensation plans, net	89	7,154			7,154
Issuance of common shares	8,625	560,739			560,739
Balance, December 31, 2008	130,866	$ 465,033	$ 1,653,797	$ (68,737)	$ 2,050,093
Comprehensive income (net of tax):					
Net income			156,929		156,929
Net change in cash flow hedges:					
Natural gas, net of tax of $27,166 (see Note 3)				44,401	44,401
Interest rate				115	115
Unrealized gain on available-for-sale securities				4,090	4,090
Pension and other post-retirement benefits liability adjustment, net of tax of $3,733				5,691	5,691
Total comprehensive income					211,226
Dividends ($0.88 per share)			(115,368)		(115,368)
Stock-based compensation plans, net	65	5,079			5,079
Balance, December 31, 2009	130,931	$ 470,112	$ 1,695,358	$ (14,440)	$ 2,151,030
Comprehensive income (net of tax):					
Net income			227,700		227,700
Net change in cash flow hedges:					
Natural gas, net of tax of $30,047 (see Note 3)				49,601	49,601
Interest rate				116	116
Unrealized gain on available-for-sale securities				806	806
Pension and other post-retirement benefits liability adjustment, net of tax of $1,331				2,021	2,021
Total comprehensive income					280,244
Dividends ($0.88 per share)			(127,292)		(127,292)
Stock-based compensation plans, net	168	6,822			6,822
Issuance of common shares	18,054	767,892			767,892
Balance, December 31, 2010	149,153	$ 1,244,826	$ 1,795,766	$ 38,104	$ 3,078,696

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

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2010

1. Summary of Significant Accounting Policies

Principles of Consolidation: The Consolidated Financial Statements include the accounts of EQT Corporation and all subsidiaries, ventures and partnerships in which a controlling equity interest is held (EQT or the Company). All significant intercompany accounts and transactions have been eliminated in consolidation. EQT utilizes the equity method of accounting for companies where its ownership is less than or equal to 50% and significant influence exists.

On June 30, 2008, the former Equitable Resources, Inc. (Old EQT) entered into and completed an Agreement and Plan of Merger under which Old EQT reorganized into a holding company structure such that a newly formed Pennsylvania corporation, also named Equitable Resources, Inc. (New EQT), became the publicly traded holding company of Old EQT and its subsidiaries. The primary purpose of this reorganization was to separate Old EQT s state-regulated distribution operations into a new subsidiary in order to better segregate its regulated and unregulated businesses and improve overall financing flexibility. New EQT changed its name to EQT Corporation effective February 9, 2009. Throughout these statements, references to EQT, EQT Corporation and the Company refer collectively to New EQT and its consolidated subsidiaries.

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

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

Cash Equivalents: The Company considers all highly liquid investments with an original maturity of three months or less when purchased to be cash equivalents. These investments are accounted for at cost. Interest earned on cash equivalents is included as a reduction of interest expense.

Inventories: Generally, the Company s inventory balance consists of natural gas stored underground or in pipelines and materials and supplies recorded at the lower of average cost or market. Included in the inventory balance at December 31, 2010 and 2009 is $11.7 million and $10.9 million, respectively, of lower of cost or market adjustments due to market natural gas prices being lower than the carrying value of natural gas stored underground. For hedged inventory the Company reclassifies unrealized hedge gains deferred in accumulated other comprehensive income into earnings in the same period as the lower of cost or market adjustment. The recording of the lower of cost or market adjustment had an immaterial impact to the Company s 2010, 2009 and 2008 earnings.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010

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

	December 31, 2010	December 31, 2009
	(Thousands)	
Oil and gas producing properties, successful efforts method	$ 4,655,217	$ 3,423,068
Accumulated depletion	967,473	797,303
Net oil and gas producing properties	3,687,744	2,625,765
Midstream plant	1,934,288	1,991,779
Accumulated depreciation and amortization	413,105	390,939
Net midstream plant	1,521,183	1,600,840
Distribution plant	976,394	944,842
Accumulated depreciation and amortization	328,781	310,026
Net distribution plant	647,613	634,816
Other properties, at cost less accumulated depreciation	53,551	53,310
Net property, plant and equipment	$ 5,910,091	$ 4,914,731

Oil and gas producing properties use the successful efforts method of accounting for production activities. Under this method, the cost of productive wells, including mineral interests, wells and related equipment, development dry holes, as well as productive acreage, are capitalized and depleted on the unit-of-production method. These capitalized costs include salaries, benefits and other internal costs directly attributable to these activities. The Company capitalized internal costs of $56.8 million, $46.5 million and $35.6 million in 2010, 2009 and 2008, respectively. The Company capitalized $7.6 million of interest relative to Marcellus Shale well development in 2010. Depletion expense is calculated based on the actual production multiplied by the applicable depletion rate per unit. The depletion rates are derived by dividing the total costs capitalized by the number of units expected to be produced over the life of the reserves. Costs of exploratory dry holes, geological and geophysical activities, delay rentals and other property carrying costs are charged to expense. The majority of the Company s oil and natural gas producing properties consist of gas producing properties which were depleted at a composite rate of $1.26/Mcfe, $1.06/Mcfe and $0.81/Mcfe produced for the years ended December 31, 2010, 2009 and 2008, respectively.

The carrying values of the Company s proved oil and gas properties are reviewed for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. In order to determine whether impairment has occurred, the Company estimates the expected future cash flows (on an undiscounted basis) from its proved oil and gas properties and compares these estimates to the carrying values of the properties. The estimated future cash flows used to test those properties for recoverability are based on proved reserves, utilizing assumptions about the use of the asset, market prices for oil and gas and future operating costs. Proved oil and gas properties that have carrying amounts in excess of estimated future cash flows would be deemed to be unrecoverable. Those properties would be written down to fair value, which would be estimated by discounting the estimated future cash flows using discount rate assumptions that marketplace participants would use in their estimates of fair value. For the years ended December 31, 2010, 2009 and 2008, the Company did not recognize impairment charges on proved oil and gas properties.

Capitalized costs of unproved properties are evaluated at least annually for recoverability on an aggregated prospect basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period in which that determination is made. Unproved properties had a net book value of $445.9 million and $105.9 million at December 31, 2010 and December 31, 2009, respectively.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010

The Company had capitalized exploratory well costs pending the determination of proved reserves of $6.9 million on an exploratory Utica well at December 31, 2008. During 2009, the Company incurred $1.0 million on this well. During 2009, the Company made the decision to plug back the well and convert it to a horizontal Marcellus Shale well in 2010. As a result, the Company wrote-off $2.9 million of incremental costs related to drilling to the Utica formation. At December 31, 2010 and 2009, the Company had no capitalized exploratory well costs. For additional information on oil and gas properties see Note 22 (unaudited).

Midstream property, plant and equipment is carried at cost. Depreciation is calculated using the straight-line method based on estimated service lives. Midstream property consists largely of gathering and transmission systems (25-60 year estimated service life), buildings (35 year estimated service life), office equipment (3-7 year estimated service life), vehicles (5 year estimated service life), and computer and telecommunications equipment and systems (3-7 year estimated service life).

Distribution property, plant and equipment, principally regulated property, is carried at cost. Depreciation is recorded using composite rates on a straight-line basis. The overall rate of depreciation for both the years ended December 31, 2010 and December 31, 2009 was approximately 4% of net properties in both years.

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

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

Regulatory Accounting: EQT Midstream s regulated operations consist of interstate pipeline operations subject to regulation by the Federal Energy Regulatory Commission (FERC) and certain state-regulated gathering operations. The Distribution segment s rates, terms of service and contracts with affiliates are subject to comprehensive regulation by the Pennsylvania Public Utility Commission (PA PUC) and the West Virginia Public Service Commission (WV PSC). The issuance of securities by Equitable Gas Company LLC, the Company s gas distribution subsidiary, is subject to regulation by the PA PUC and WV PSC. Distribution also provides field line service, also referred to as farm tap service, in Kentucky, which is subject only to rate regulation by the Kentucky Public Service Commission. The application of regulatory accounting allows the Company to defer expenses and income on its Consolidated Balance Sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the Statements of Consolidated Income for a non-regulated company. The deferred regulatory assets and liabilities are then recognized in the Statements of Consolidated Income in the period in which the same amounts are reflected in rates.

Where permitted by regulatory authority under purchased natural gas adjustment clauses or similar tariff provisions, Distribution defers the difference between its purchased natural gas cost, less refunds, and the billing of such cost and amortizes the deferral over subsequent periods in which billings either recover or repay such amounts. Such amounts are reflected on the Company s Consolidated Balance Sheets as other current assets or liabilities. For further information regarding regulatory assets, see Note 10.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010

The following table presents the total regulated net revenues and operating expenses of the Company:

	Years Ended December 31, 2010	2009	2008
	(Thousands)		
Distribution revenues	$ 411,978	$ 507,481	$ 650,197
Midstream revenues	124,958	112,778	83,374
Total regulated revenue	$ 536,936	$ 620,259	$ 733,571
Distribution purchased gas costs	$ 231,407	$ 334,144	$ 487,318
Midstream purchased gas costs	4,930	1,035	
Total purchased gas costs	$ 236,337	$ 335,179	$ 487,318
Distribution net revenue	$ 180,571	$ 173,337	$ 162,879
Midstream net revenue	120,028	111,743	83,374
Total regulated net revenue	$ 300,599	$ 285,080	$ 246,253
Distribution operating expenses	$ 103,915	$ 100,567	$ 110,587
Midstream operating expenses	65,029	66,355	53,825
Total regulated operating expenses	$ 168,944	$ 166,922	$ 164,412

The following table presents the regulated net property, plant and equipment of the Company:

	As of December 31, 2010	2009
	(Thousands)	
Distribution property, plant & equipment	$ 976,394	$ 944,842
Accumulated depreciation and amortization	328,781	310,026
Net Distribution property, plant & equipment	647,613	634,816
Midstream property, plant & equipment	701,936	670,400
Accumulated depreciation and amortization	160,269	151,625
Net Midstream property, plant & equipment	541,667	518,775
Total net regulated property, plant & equipment	$ 1,189,280	$ 1,153,591

Derivative Instruments: Derivatives are held as part of a formally documented risk management program. The Company s risk management activities are subject to the management, direction and control of the Company s Corporate Risk Committee (CRC). The CRC reports to the Audit Committee of the Board of Directors and is comprised of the president and chief executive officer, the chief financial officer, the chief risk officer and other officers and employees.

The Company s risk management program includes the consideration and, when appropriate, the use of (i) exchange-traded natural gas futures contracts and options and over the counter (OTC) natural gas swap agreements and options (collectively, derivative commodity instruments) to hedge exposures to fluctuations in natural gas prices and for trading purposes and (ii) interest rate swap agreements to hedge exposures to fluctuations in interest rates. At contract inception, the Company designates its derivative instruments as hedging or trading activities.

The Company recognizes all derivative instruments as either current assets or current liabilities at fair value due to their highly liquid nature. The Company can net settle its derivative instruments at any time. The measurement of fair value is based upon actively quoted market prices when available. In the absence of actively

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010

quoted market prices, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based upon valuation methodologies deemed appropriate by the Company s CRC.

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

If a cash flow hedge is terminated or de-designated as a hedge before the settlement date of the hedged item, the amount of accumulated other comprehensive income (loss) recorded up to that date remains accrued provided that the forecasted transaction remains probable of occurring and subsequent changes in fair value of the derivative instrument are recorded in earnings. The derivative instruments that comprise the amount recorded in accumulated other comprehensive income (loss) are primarily instruments which are designated and qualify as cash flow hedges. During 2008, the Company entered into derivative transactions which had the effect of offsetting existing cash flow hedges, resulting in an effective reduction in the hedge position for years 2010 through 2013. The Company concurrently de-designated the original transactions. The fair value of these derivative instruments was a net $11.1 million liability at December 31, 2010. In addition, during the first quarter of 2009, the Company terminated additional cash flow hedges scheduled to mature during the period 2010 through 2012. As of December 31, 2010, the fair value of these derivative instruments was a net $4.4 million asset. These amounts will be recognized as part of the realized sales price in the Consolidated Statements of Income when the underlying physical transactions occur. The Company does not treat these derivatives as hedging instruments. These amounts are included in the Consolidated Balance Sheets as derivative instruments, at fair value.

The Company reports all gains and losses on its energy trading contracts net on its Statements of Consolidated Income.

Allowance for Funds Used During Construction: The Company capitalizes the carrying costs for the construction of certain regulated long-term assets and amortizes the costs over the life of the related assets. The calculated allowance for funds used during construction (AFUDC) includes capitalization of the cost of financing construction of assets subject to regulation by the PA PUC, the WV PSC or the FERC. A computed interest cost and a designated cost of equity for financing the construction of these regulated assets are recorded in the Company s income statement.

The debt portion of AFUDC is calculated based on the average cost of debt and is included as a reduction of interest expense in the Statements of Consolidated Income. AFUDC interest costs were $1.1 million, $0.4 million and $2.1 million for the years ended December 31, 2010, 2009 and 2008, respectively.

The equity portion of AFUDC is calculated using the most recent equity rate of return approved by the applicable regulator. Equity amounts capitalized are included in other income in the Statements of Consolidated Income. The AFUDC equity amounts capitalized were $0.3 million, $1.2 million and $6.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Capitalized Interest: Interest costs for the construction of certain long-term assets in unregulated Company businesses are capitalized and amortized over the related assets estimated useful lives. The Company capitalized interest costs of $8.2 million, $3.8 million and $14.9 million, during 2010, 2009 and 2008 respectively, as a portion of the cost of the related long-term assets.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010

Impairment of Long-Lived Assets: When events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable, the Company reviews its long-lived assets for impairment by first comparing the carrying value of the assets to the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the assets. If the carrying value exceeds the sum of the assets undiscounted cash flows, the Company records an impairment loss equal to the difference between the carrying value and fair value of the assets.

Other Current Liabilities: Included in other current liabilities in the Company s Consolidated Balance Sheets is approximately $88 million and $70 million of incentive compensation at December 31, 2010 and December 31, 2009, respectively.

Revenue Recognition: Revenue is recognized for production and gathering activities when deliveries of natural gas, NGLs and crude oil are made. Revenues from natural gas transportation and storage activities are recognized in the period the service is provided. Sales of natural gas to distribution customers are billed on a monthly cycle basis; however, the billing cycles for certain customers do not coincide with accounting periods used for financial reporting purposes. The Company follows the revenue accrual method of accounting for Distribution segment revenue whereby revenues applicable to gas delivered to customers but not yet billed under the cycle billing method are estimated and accrued and the related costs are charged to expense. The Company reports revenue from all energy trading contracts net in the income statement, regardless of whether the contracts are physically or financially settled. Contracts which result in physical delivery of a commodity expected to be used or sold by the Company in the normal course of business are considered normal purchases and sales and are not subject to mark-to-market accounting. Revenues from these contracts are recognized at contract value when delivered. Revenues associated with energy trading contracts that do not result in physical delivery of an energy commodity are classified as derivative instruments and are recorded using mark-to-market accounting. Revenues associated with the Company s natural gas advance sales contracts are recognized as natural gas is gathered and delivered. The Company accounts for gas-balancing arrangements under the entitlement method. The Company uses the gross method to account for overhead cost reimbursements from joint operating partners. During periods in which rates are subject to refund as a result of a pending rate case, the Company records revenue at the rates which are pending approval but reserves these revenues to the level of previously approved rates until the final settlement of the rate case.

Investments: Investments in companies in which the Company has the ability to exert significant influence over operating and financial policies (generally 20% to 50% ownership) are accounted for using the equity method. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. These investments are classified as equity in nonconsolidated investments on the Consolidated Balance Sheets. The Company recognizes a loss in the value of an equity method investment that is other than a temporary decline. The Company analyzes its equity method investments based on its share of estimated future cash flows from the investment to determine whether the carrying amount will be recoverable.

Other investments in equity securities which are generally under 20% ownership and where the Company does not exert significant influence over operating and financial polices are accounted for as available-for-sale and are classified as investments, available-for-sale on the Consolidated Balance Sheets. Available-for-sale securities are required to be carried at fair value, with any unrealized gains and losses reported on the Consolidated Balance Sheets within a separate component of equity, accumulated other comprehensive income (loss). The Company utilizes the average cost method to determine the cost of the securities. The Company continually reviews its available-for-sale securities to determine whether a decline in fair value below the cost basis is other than temporary. If the decline in fair value is judged to be other than temporary, the cost basis of the security is written down to fair value and the amount of the write-down is included in the Statements of Consolidated Income. The Company recorded an other than temporary impairment of $7.8 million in 2008. See Note 9. No other than temporary decline in fair value was recorded in 2010 or 2009.

Purchased Gas Costs: Purchased gas costs in the Statements of Consolidated Income include natural gas wellhead purchases, natural gas field line purchases, natural gas transmission line purchases, purchased gas cost

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010

adjustments, natural gas withdrawn from storage, gas used for product extraction and other gas supply expenses, including pipeline demand charges and related transportation costs of purchased gas.

Income Taxes: The Company files a consolidated federal income tax return and utilizes the asset and liability method to account for income taxes. The provision for income taxes represents amounts paid or estimated to be payable, net of amounts refunded or estimated to be refunded, for the current year and the change in deferred taxes, exclusive of amounts recorded in other comprehensive income. Any refinements to prior years taxes made due to subsequent information are reflected as adjustments in the current period. Separate income taxes are calculated for income from continuing operations and items charged or credited directly to stockholders equity.

Deferred income tax assets and liabilities are determined based on temporary differences between the financial reporting and tax bases of assets and liabilities and are recognized using enacted tax rates for the effect of such temporary differences. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. Where deferred tax liabilities will be passed through to customers in regulated rates, the Company establishes a corresponding regulatory asset for the increase in future revenues that will result when the temporary differences reverse.

Investment tax credits realized in prior years were deferred and are being amortized over the estimated service lives of the related properties where required by ratemaking rules.

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

Provision for Doubtful Accounts: Judgment is required to assess the ultimate realization of the Company s accounts receivable, including assessing the probability of collection and the credit worthiness of certain customers. Reserves for uncollectible accounts are recorded as part of selling, general and administrative expense on the Statements of Consolidated Income. The reserves are based on historical experience, current and expected economic trends and specific information about customer accounts. Accordingly, actual results may differ from these estimates under different assumptions or conditions.

Earnings Per Share (EPS): Basic EPS were computed by dividing net income by the weighted average number of common shares outstanding during the period, without considering any dilutive items. Diluted EPS were computed by dividing net income by the weighted average number of common shares and potentially dilutive securities, net of shares assumed to be repurchased using the treasury stock method. Purchases of treasury shares are calculated using the average share price for the Company s common stock during the period. Potentially dilutive securities arise from the assumed conversion of outstanding stock options and other share-based awards. See Note 14.

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

The Company is required to operate and maintain its natural gas pipeline and storage systems, and intends to do so as long as supply and demand for natural gas exists, which the Company expects for the foreseeable future.

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Therefore, the Company believes that the substantial majority of its natural gas pipeline and storage system assets have indeterminate lives.

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

	Years ended December 31, 2010 (Thousands)
Asset retirement obligation as of beginning of period	$ 60,961
Accretion expense	4,633
Liabilities incurred	2,280
Liabilities settled	(1,559)
Asset retirement obligation as of end of period	$ 66,315

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

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

2. Financial Information by Business Segment

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

The Company reports its operations in three segments, which reflect its lines of business. The EQT Production segment includes the Company s exploration for, and development and production of, natural gas, natural gas liquids and a limited amount of crude oil in the Appalachian Basin. EQT Midstream s operations include the natural gas gathering, transportation, storage and marketing activities of the Company. Until February 1, 2011, EQT Midstream also provided processing services. Distribution s operations primarily comprise the state-regulated distribution activities of the Company.

On February 1, 2011, the Company sold its natural gas processing complex in Langley, Kentucky. Subsequent to the closing of the sale, the processing of the Company s produced natural gas has been performed by a third-party vendor. The incremental revenue received as a result of the fractionation of NGLs which were extracted from the Company s produced natural gas (frac spread) was previously reported in the EQT Midstream segment in conjunction with the results of the processing activities. As a result of the sale of the Company s processing assets, management determined that this frac spread would be reported in the EQT Production segment as additional revenue for its produced natural gas sales. The segment disclosures and discussions contained in this report have been reclassified to reflect all periods presented under the new methodology.

Operating segments are evaluated on their contribution to the Company s consolidated results based on operating income, equity in earnings of nonconsolidated investments and other income. Interest expense and

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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 are not allocated to the operating segments.

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

	Years Ended December 31,		
	2010	**2009**	**2008**
		(Thousands)	
Revenues from external customers:			
EQT Production	$ 537,657	$ 420,990	$ 472,961
EQT Midstream	580,698	465,444	597,073
Distribution	474,143	560,283	698,385
Less: intersegment revenues (a)	(269,790)	(176,890)	(191,931)
Total	$ 1,322,708	$ 1,269,827	$ 1,576,488
Operating income:			
EQT Production	$ 223,487	$ 185,868	$ 267,620
EQT Midstream	178,866	154,197	119,936
Distribution	83,182	78,918	59,859
Unallocated (expenses) income (b)	(15,056)	(62,192)	17,391
Total operating income	$ 470,479	$ 356,791	$ 464,806

Reconciliation of operating income to net income:			
Equity in earnings of nonconsolidated investments:			
EQT Production	$ 93	$ 89	$ 440
EQT Midstream	9,532	6,376	5,053
Unallocated	47	44	221
Total	$ 9,672	$ 6,509	$ 5,714
Other income:			
EQT Midstream	$ 509	$ 1,357	$ 5,678
Distribution	638	342	555
Unallocated		377	
Total	$ 1,147	$ 2,076	$ 6,233
Other than temporary impairment of available-for-sale securities			(7,835)
Gain on sale of available-for-sale securities, net	2,079		
Interest expense	128,157	111,779	58,394

Income taxes	127,520	96,668	154,920
Net income	$ 227,700	$ 156,929	$ 255,604

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	As of December 31, 2010	2009
	(Thousands)	
Segment assets:		
EQT Production	$ 3,979,676	$ 2,931,053
EQT Midstream	2,076,485	1,984,525
Distribution	848,419	860,222
Total operating segments	6,904,580	5,775,800
Headquarters assets, including cash and short-term investments	193,858	181,457
Total assets	$ 7,098,438	$ 5,957,257

	Years Ended December 31, 2010	2009	2008
	(Thousands)		
Depreciation, depletion and amortization:			
EQT Production	$ 183,699	$ 117,424	$ 78,234
EQT Midstream	61,863	53,291	34,802
Distribution	24,174	22,375	22,055
Other	549	2,988	1,725
Total	$ 270,285	$ 196,078	$ 136,816
Expenditures for segment assets:			
EQT Production (c)	$ 1,245,914	$ 717,356	$ 700,745
EQT Midstream	193,128	201,082	593,564
Equitable Distribution	36,619	33,707	45,770
Other	1,958	11,763	3,917
Total	$ 1,477,619	$ 963,908	$ 1,343,996

(a) Intersegment revenues primarily represent natural gas sales from EQT Production to EQT Midstream and transportation activities between EQT Midstream and Distribution.

(b) Unallocated (expenses) income consists primarily of incentive compensation and administrative costs that are not allocated to the operating segments.

(c) Expenditures for segment assets in the EQT Production segment include $357.7 million, $31.0 million and $85.5 million for undeveloped property acquisitions in 2010, 2009 and 2008, respectively. The undeveloped property acquisition amount for 2010 includes $230.7 million of undeveloped property which was acquired with EQT common stock.

3. Derivative Instruments

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

The Company uses non-leveraged derivative commodity instruments that are placed with major financial institutions whose creditworthiness is continually monitored. Futures contracts obligate the Company to buy or sell a designated commodity at a future date for a specified price and quantity at a specified location. Swap agreements involve payments to or receipts from counterparties based on the differential between a fixed and variable price for the commodity. Collar agreements require the counterparty to pay the Company if the index price falls below the floor price and the Company to pay the counterparty if the index price rises above the cap price. Put option contracts provide protection from dropping prices and require the counterparty to pay the Company if the index price falls below the contract price. The Company also engages in a limited number of basis swaps to protect

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earnings from undue exposure to the risk of geographic disparities in commodity prices and interest rate swaps to hedge exposure to interest rate fluctuations on short or long-term debt.

The Company recognizes all derivative instruments as either assets or liabilities at fair value. The accounting for the changes in fair value of the Company s derivative instruments depends on the use of the derivative instruments. At contract inception, the Company designates its derivative instruments as hedging or trading activities. To the extent that a derivative instrument has been designated and qualifies as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of accumulated other comprehensive income (OCI) (loss), net of tax, and is subsequently reclassified into earnings, in the same line item associated with the forecasted transaction, in the same period or periods during which the hedged forecasted transaction affects earnings. For derivative instruments that have not been designated as cash flow hedges, the change in fair value for the instrument is recognized in the Statements of Consolidated Income as operating revenues each period.

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

The derivative commodity instruments used by the Company to hedge its exposure to variability in expected future cash flows associated with the fluctuations in the price of natural gas related to the Company s forecasted sale of equity production and forecasted natural gas purchases and sales have been designated and qualify as cash flow hedges under Accounting Standards Codification Topic 815, Derivatives and Hedging. The current hedge position extends through 2015. See Commodity Risk Management in Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K for further details of the Company s hedged position.

The Company assesses the effectiveness of hedging relationships, the degree to which the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, both at the inception of the hedge and on an on-going basis. If the gain (loss) for the hedging instrument is greater than the loss (gain) on the hedged item, the ineffective portion of the cash flow hedge is immediately recognized in operating revenues in the Statements of Consolidated Income.

The Company also enters into a limited amount of energy trading contracts to leverage its assets and limit its exposure to shifts in market prices and has a limited amount of other derivative instruments not designated as hedges.

All derivatives recognized in the balance sheet and used in cash flow hedging relationships are commodity contracts. All gains (losses) recognized in income or reclassified from accumulated other comprehensive income (loss) into income are reported in operating revenues. All derivative instrument assets and liabilities are reported in the balance sheet as derivative instruments, at fair value. These derivative instruments are reported as either current assets or current liabilities due to their highly liquid nature. The Company can net settle its derivative instruments at any time.

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	Years Ended December 31,		
	2010	**2009**	**2008**
		(Thousands)	
Derivatives designated as hedging instruments			
Amount of gain recognized in OCI (effective portion), net of tax	$ 113,320	$ 148,327	$ 163,731
Amount of gain reclassified from accumulated OCI into income (effective portion), net of tax (a)	63,719	103,926	(93,711)
Amount of gain (loss) recognized in income (ineffective portion) (b)	3,046	(2,068)	808
Derivatives not designated as hedging instruments:			
Amount of gain (loss) recognized in income	$ 369	$ 65	$ (403)

	December 31,	
	2010	**2009**
	(Thousands)	
Asset derivatives		
Derivatives designated as hedging instruments	$ 141,834	$ 111,375
Derivatives not designated as hedging instruments (c)	83,505	52,504
Total asset derivatives	$ 225,339	$ 163,879
Liability derivatives		
Derivatives designated as hedging instruments	$ 12,097	$ 61,179
Derivatives not designated as hedging instruments (c)	94,624	71,339
Total liability derivatives	$ 106,721	$ 132,518

(a) Includes $6.2 million, $5.1 million and $32.8 million for the years ended December 31, 2010, 2009 and 2008, respectively, of unrealized hedge gains reclassified into earnings to offset lower of cost or market adjustments on hedged items. The Company also had an immaterial amount of OCI reclassified to interest expense related to an interest rate swap on long-term debt.

(b) No amounts have been excluded from effectiveness testing.

(c) As previously discussed, these amounts include offsetting positions that were entered into when certain derivatives were de-designated as hedges.

The net fair value of derivative instruments changed during 2010 primarily as a result of changes in natural gas prices. The absolute quantities of the Company s derivative commodity instruments that have been designated and qualify as cash flow hedges totaled 181 Bcf and 172 Bcf as of December 31, 2010 and December 31, 2009, respectively, and are primarily related to natural gas swaps and collars.

The Company deferred net gains of $65.2 million and $15.6 million in accumulated other comprehensive income (loss), net of tax, as of December 31, 2010 and December 31, 2009, respectively, associated with the effective portion of the change in fair value of its derivative commodity instruments designated as cash flow hedges. Assuming no change in price or new transactions, the Company estimates that approximately $27.2 million of net unrealized gains on its derivative commodity instruments reflected in accumulated other comprehensive income (loss), net of tax, as of December 31, 2010 will be recognized in earnings during the next twelve months due to the settlement of hedged transactions. This recognition occurs through an increase in the Company s net operating revenues resulting in the average hedged price becoming the realized sales price.

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value. The Company believes that New York Mercantile Exchange (NYMEX) traded futures contracts have minimal credit risk because

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Commodity Futures Trading Commission regulations are in place to protect exchange participants, including the Company, from potential financial instability of the exchange members. The Company s swap, collar and option derivative instruments are primarily with financial institutions and thus are subject to events that would impact those companies individually as well as that industry as a whole.

The Company utilizes various processes and analysis to monitor and evaluate its credit risk exposures. This includes closely monitoring current market conditions, counterparty credit spreads and credit default swap rates. Credit exposure is controlled through credit approvals and limits. To manage the level of credit risk, the Company deals with financial counterparties that are of investment grade, enters into netting agreements whenever possible and may obtain collateral or other security.

When the net fair value of any of the Company s swap agreements represents a liability to the Company which is in excess of the agreed-upon threshold between the Company and the financial institution acting as counterparty, the counterparty requires the Company to remit funds to the counterparty as a margin deposit for the derivative liability which is in excess of the threshold amount. The Company records these deposits as a current asset in the Consolidated Balance Sheets. When the net fair value of any of the Company s swap agreements represents an asset to the Company which is in excess of the agreed-upon threshold between the Company and the financial institution acting as counterparty, the Company requires the counterparty to remit funds as margin deposits in an amount equal to the portion of the derivative asset which is in excess of the threshold amount. The Company records a current liability for such amounts received. The Company had no such deposits in its Consolidated Balance Sheets as of December 31, 2010 and December 31, 2009.

When the Company enters into exchange-traded natural gas contracts, exchanges may require the Company to remit funds to the corresponding broker as good-faith deposits to guard against the risks associated with changing market conditions. Participants must make such deposits based on an established initial margin requirement as well as the net liability position, if any, of the fair value of the associated contracts. The Company records these deposits as a current asset in the Consolidated Balance Sheets. In the case where the fair value of such contracts is in a net asset position, the broker may remit funds to the Company, in which case the Company records a current liability for such amounts received. The initial margin requirements are established by the exchanges based on the price, volatility and time to expiration of the related contract and are subject to change at the exchanges discretion. The Company recorded current liabilities of $0.5 million and $6.9 million as of December 31, 2010 and 2009, respectively, for such deposits with brokers in its Consolidated Balance Sheets.

Certain of the Company s derivative instrument contracts provide that if the Company s credit ratings are lowered below investment grade, additional collateral must be deposited with the counterparty. Contracts have differing terms in that some require collateral if just one of the ratings agencies downgrades the Company to a level below investment grade, while others refer to the rating of just one ratings agency and still others have no ratings trigger. If required, this additional collateral can be up to 100% of the derivative liability. As of December 31, 2010, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $8.7 million, for which the Company had no collateral posted on December 31, 2010. If the Company s credit rating had been downgraded below investment grade on December 31, 2010, the Company would have been required to post additional collateral of $8.7 million in respect of the liability position. Investment grade refers to the quality of the Company s credit as assessed by one or more credit rating agencies. The Company s long-term corporate credit rating at December 31, 2010 was BBB by Standard & Poor s Rating Services (S&P), Baa1 by Moody s Investor Services (Moody s) and BBB+ by Fitch Ratings Service (Fitch). In order to be considered investment grade, the Company must be rated BBB- or higher by S&P and Fitch and Baa3 or higher by Moody s. Anything below these ratings is considered non-investment grade.

4. Fair Value Measurements

The Company has an established process for determining fair value for its financial instruments, principally derivative commodity instruments and available-for-sale investments. Fair value is based on quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use as inputs market-based parameters, including but not limited to forward curves, discount rates, broker quotes, volatilities, and nonperformance risk. Nonperformance risk considers, among other things, the effect of the Company s credit standing on the fair value of liabilities and the effect of the counterparty s credit standing on the fair value of assets.

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The Company estimates nonperformance risk by analyzing publicly available market information, including a comparison of the yield on debt instruments with credit ratings similar to the Company s or counterparty s credit rating and the yield of a risk free instrument. The Company also considers credit default swaps rates where applicable.

The Company has categorized its financial instruments into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Financial instruments included in Level 1 include the Company s futures contracts and available-for-sale investments, while instruments included in Level 2 include the majority of the Company s swap agreements and instruments included in Level 3 include the Company s collar and option agreements and a portion of the Company s swap agreements. Since the adoption of fair value accounting, the Company has not made any changes to its classification of financial instruments in each category.

The fair value of financial instruments included in Level 2 is based on industry models that use significant observable inputs, including NYMEX forward curves and LIBOR-based discount rates. Swaps included in Level 3 are valued using internal models that use significant unobservable inputs; these internal models are validated each period with non-binding broker price quotes. The Company has not experienced significant differences between internally calculated values and broker price quotes. Collars and options included in Level 3 are valued using internal models calculated with market derived volatilities. The Company uses NYMEX forward curves to value futures, NYMEX swaps, collars and options. The NYMEX forward curves are validated to external sources at least monthly.

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

		Fair value measurements at reporting date using		
Description	**December 31, 2010**	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
		(Thousands)		
Assets				
Investments, available-for-sale	$ 28,968	$ 28,968	$	$
Derivative instruments, at fair value	225,339	8,968	99,489	116,882
Total assets	$ 254,307	$ 37,936	$ 99,489	$ 116,882
Liabilities				
Derivative instruments, at fair value	$ 106,721	$ 7,627	$ 98,884	$ 210

Total liabilities	$ 106,721	$ 7,627	$ 98,884	$ 210

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	Fair value measurements using significant unobservable inputs (Level 3)
	Derivative instruments, at fair value, net (Thousands)
Balance at January 1, 2010	$ 88,570
Total gains or losses:	
Included in earnings	(14)
Included in other comprehensive income	87,330
Purchases, issuances and settlements	(59,214)
Transfers in and/or out of Level 3	
Balance at December 31, 2010	$ 116,672
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities still held as of December 31, 2010	$ 5

Gains and losses related to derivative commodity instruments included in earnings for the period are reported in operating revenues in the Statements of Consolidated Income. All realized gains or losses related to available-for-sale securities are included in separate line items on the Statements of Consolidated Income.

The carrying value of cash equivalents and short-term loans approximates fair value due to the short maturity of the instruments.

The estimated fair value of long-term debt on the Consolidated Balance Sheets at both December 31, 2010 and December 31, 2009 was approximately $2 billion. The fair value was estimated using the Company s established fair value methodology based on quoted rates reflective of the remaining maturity.

For information on the fair value of the defined benefit pension plan assets see Note 13.

5. Sale of Properties

On February 1, 2011, the Company sold its natural gas processing complex in Langley, Kentucky and associated natural gas liquids pipeline for $230 million subject to customary purchase price adjustments. The Langley processing complex includes a 100 million cubic feet per day (MMcfd) cryogenic processing plant, a 75 MMcfd refrigeration processing plant and approximately 28,000 horsepower of compression. As of December 31, 2010, EQT classified the Langley properties as assets held for sale in the accompanying Consolidated Balance Sheets. In conjunction with the closing of the sale, the Company executed a long-term agreement to receive processing services for its Kentucky Huron Shale gas and extended its existing agreement for NGL transportation, fractionation and marketing services until 2022. Expenses incurred during 2010 to operate the plant, excluding DD&A, were $20.2 million. If the natural gas volumes processed by the Kentucky Hydrocarbon complex in 2010 would have been processed by a third-party, the Company would have incurred approximately $35.1 million in processing fees and expenses.

6. Acquisitions

During 2010, the Company acquired approximately 58,000 net acres in the Marcellus Shale from a group of private operators and landowners. The acreage is located primarily in Cameron, Clearfield, Elk and Jefferson counties in Pennsylvania. The purchase included a 200 mile gathering system, with associated rights of way, and

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approximately 100 producing vertical wells. The Company paid $282.2 million for these assets, $230.7 million in EQT stock and $51.5 million in cash.

7. Income Taxes

Income tax (benefit) expense is summarized as follows:

	Years Ended December 31,		
	2010	2009	2008
		(Thousands)	
Current:			
Federal	$ (25,377)	$(134,763)	$ (89,630)
State	(388)	(2,712)	(614)
Subtotal	(25,765)	(137,475)	(90,244)
Deferred:			
Federal	132,161	223,177	238,034
State	21,751	11,599	7,767
Subtotal	153,912	234,776	245,801
Amortization of deferred investment tax credit	(627)	(633)	(637)
Total	$ 127,520	$ 96,668	$ 154,920

The current federal tax benefit recorded in 2010 primarily relates to additional cash refunds received during the year related to the 2009 tax net operating loss carryback and certain other IRS adjustments for the 2006 to 2009 audit cycle.

On December 17, 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (2010 Tax Relief Act) was enacted. Among the provisions included in this law were the extension of the research and experimentation (R&E) tax credit for 2010 and 2011 and an increase for bonus depreciation from 50% to 100% for qualified investments made after September 8, 2010 and before January 1, 2012. The 2010 Tax Relief Act also extends the 50% bonus depreciation for property placed in service after December 31, 2011 and before January 1, 2013.

On November 6, 2009, the Worker, Homeownership, and Business Assistance Act of 2009 was enacted. This law extended the applicability of the tax net operating loss carryback provision from 2 years to 5 years for either the 2008 or 2009 tax year. The Company elected to carryback its 2009 tax net operating loss and received a refund of $121.5 million during the first quarter of 2010. During the third quarter of 2010 the Company filed a superseding tax return for the 2009 tax year and received an additional refund of $1.9 million relating to the carryback of the

2009 net operating tax loss. EQT also received refunds of $115.2 million, primarily in the second quarter of 2009, relating to the 2008 net operating loss carryback. The net operating losses in 2010, 2009 and 2008 were primarily generated from intangible drilling costs (IDC) for the Company s drilling program that are deducted currently for tax purposes and from accelerated tax depreciation associated with the expansion of the Company s midstream business. For federal income tax purposes, the Company currently deducts approximately 80% of drilling costs as IDCs in the year incurred.

Because the Company was in an overall federal tax net operating loss position for 2010, 2009 and 2008, the Company expects to pay minimal federal income taxes for the next few years as the Company s drilling program in Appalachia continues to generate intangible drilling cost deductions, unless tax laws change or the Company incurs an unexpected taxable gain from a transaction.

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

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DECEMBER 31, 2010

	Years Ended December 31,		
	2010	2009	2008
		(Thousands)	
Tax at statutory rate	$ 124,327	$ 88,759	$ 143,683
Incentive or deferred compensation		8,925	172
State income taxes	10,803	8,681	4,511
Federal tax credits and incentives	(600)	1,613	1,968
Regulatory basis differences	(2,713)	(9,336)	1,132
Permanent basis differences	(1,258)	(3,025)	(3,500)
Other	(3,039)	1,051	6,954
Income tax expense	$ 127,520	$ 96,668	$ 154,920
Effective tax rate	35.9%	38.1%	37.7%

The Company estimates an annual effective income tax rate based on projected results for the year and applies this rate to income before taxes to calculate income tax expense. The effective tax rate is further adjusted for non-recurring discrete items. Refinements made due to subsequent information that affects the estimated annual effective income tax rate are reflected as adjustments in the current period.

The Company s effective tax rate for its continuing operations for the year ended December 31, 2010 was 35.9% compared to 38.1% for the year ended December 31, 2009. The higher tax rate in 2009 is primarily the result of the impact in 2009 of certain nondeductible expenses and the loss of certain prior year deductions as a result of carrying 2009 losses back to receive a cash refund of taxes paid. These higher rates in 2009 were partially mitigated by a regulatory asset recorded to recover deferred taxes caused by an accounting method change that deducts as repairs certain costs capitalized for financial accounting purposes in 2009. Rates were also lower in 2010 due to the reduction of the reserve for uncertain tax positions due to the lapse of applicable statutes of limitation.

The Company s effective tax rate for its continuing operations for the year ended December 31, 2009 was 38.1% compared to 37.7% for the year ended December 31, 2008. The higher tax rate in 2009 is primarily the result of nondeductible compensation expense partially offset by a regulatory asset recorded to recover deferred taxes caused by an accounting method change discussed below. In addition, the Company recorded a tax benefit in 2008 for a change in the West Virginia state tax law that provided for a reduction in the future corporate income tax rates which was partially offset by additional tax expense as a result of the completion of the IRS audit through the 2005 tax year.

Section 162(m) of the Internal Revenue Code disallows, with certain exceptions such as performance based compensation paid pursuant to a shareholder approved plan, a federal income tax deduction for annual compensation over $1 million paid to any covered employee. The covered employees are the principal executive officer and the three most highly-compensated officers other than the principal executive officer and the principal financial officer. During 2009, payments awarded under the 2009 Shareholder Value Plan were subject to this limitation which resulted in $8.9 million of tax expense.

During 2008, the Company applied for a change in accounting method that would allow current income tax deductions for certain repair costs that are capitalized for book purposes. However, the method request was a non-automatic change and required the consent of the IRS. During the fourth quarter of 2009 the Company received consent from the IRS to change and reflected the change in the quarterly results. As a result of the tax treatment of certain accelerated deductions for regulatory purposes, a portion of the tax benefit of these deductions is reflected as a regulatory asset and is anticipated to be collected in the future when the deferred taxes become current. Thus, the Company is required to record a regulatory asset to reflect the future recovery of these deferred taxes when the temporary differences reverse. The overall tax expense decreased by $9.8 million in 2009 due to the establishment of the regulatory asset.

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

	2010	2009	2008
		(Thousands)	
Balance at January 1	$ 40,726	$ 34,171	$ 31,367
Additions based on tax positions related to current year	1,474	10,622	5,628
Additions for tax positions of prior years	356	672	2,286
Reductions for tax positions of prior years	(9,017)	(1,550)	(854)
Settlements			(3,170)
Lapse of statute of limitations	(4,080)	(3,189)	(1,086)
Balance at December 31	$ 29,459	$ 40,726	$ 34,171

Included in the tabular reconciliation above at December 31, 2010, December 31, 2009 and December 31, 2008 are $18.2 million, $29.5 million and $20.2 million, respectively, for tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income tax expense. The Company reversed approximately $3.9 million of previously recorded interest expense in 2010. During the year ended December 31, 2009, the Company recognized approximately $2.5 million of interest expense and for the year ended December 31, 2008, the Company reversed approximately $6.1 million of previously recorded interest expense. Interest and penalty of $12.0 million, $15.9 million and $13.4 million is included in the balance sheet reserve at December 31, 2010, 2009 and 2008, respectively.

The total amount of unrecognized tax benefits, inclusive of interest and penalties, was $41.5 million, $56.6 million and $47.6 million as of December 31, 2010, 2009 and 2008, respectively. The total amount of unrecognized tax benefits (excluding interest and penalties) that, if recognized, would affect the effective tax rate was $8.9 million, $8.9 million and $10.7 million as of December 31, 2010, 2009 and 2008, respectively.

As of December 31, 2010, it is reasonably possible that the total amount of unrecognized tax benefits could decrease by up to $22.9 million within the next 12 months due to potential settlements with taxing authorities, legal or administrative guidance by relevant taxing authorities or the lapse of applicable statutes of limitation.

There were no material changes to the Company s methodology for unrecognized tax benefits during 2010. Because the Company is in a net operating loss position, the Company is not creating unrecognized tax benefits for certain tax positions which instead reduce the net operating loss. In addition, decreases to the unrecognized tax benefit balance during 2010 were primarily attributable to the reversal of certain prior year tax positions related to timing differences and the lapse of applicable statutes of limitations.

The consolidated federal income tax liability of the Company has been settled with the IRS through 2005 with the exception of R&E credit items. In December 2008, the Joint Committee on Taxation (JCT) approved the settlement of all issues related to the 1998 through 2000 audit. The Company received a final net tax refund of $4.6 million, including interest, for those years. For the period 2001 through 2005, a restricted waiver was executed extending the statute of limitations for R&E credit items only until September 30, 2011. In September of 2009, the JCT approved the settlement of all issues related to the 2001 to 2005 audit excluding the R&E credits claimed for such years which have been referred to the Appeals Division of the IRS. The appeals pre-conference was held in October of 2010; however, a closing agreement has not yet been finalized. The R&E credits for this period total $3.8 million.

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The Company is currently under audit for the 2006 to 2009 periods. The examination of these periods began in the second quarter of 2010. The Company believes that it is appropriately reserved for any uncertain state tax positions claimed during the periods to be reviewed.

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

	December 31,	
	2010	**2009**
	(Thousands)	
Deferred income taxes:		
Total deferred income tax assets	$ (385,948)	$ (111,530)
Total deferred income tax liabilities	1,622,520	1,149,968
Total net deferred income tax liabilities	1,236,572	1,038,438
Total deferred income tax liabilities (assets)		
Tax depreciation in excess of book depreciation	918,567	652,984
Drilling and development costs expensed for income tax reporting	632,985	438,924
Regulatory temporary differences	44,335	50,987
Accumulated other comprehensive income (loss)	21,217	(10,595)
Deferred purchased gas cost	5,113	7,073
Financial instruments	302	(194)
Investment tax credit	(1,856)	(2,353)
Uncollectible accounts	(4,092)	(4,971)
Post-retirement benefits	(6,630)	(7,099)
Deferred compensation plans	(15,698)	(6,260)
Incentive compensation	(15,971)	(4,336)
Alternative minimum tax credit carryforward	(26,017)	(26,017)
Net operating loss carryforwards	(305,787)	(34,026)
Other	(9,896)	(15,679)
Total (including amounts classified as current (assets) liabilities of $(33,586) and $4,727, respectively)	$1,236,572	$1,038,438

The net deferred tax liability relating to the Company s accumulated other comprehensive income balance as of December 31, 2010 was comprised of a $39.6 million deferred tax liability related to the Company s net unrealized gain from hedging transactions, a $2.6 million deferred tax liability related to the unrealized gain on available-for-sale securities, a $7.0 million deferred tax asset related to other post-retirement benefits and a $14.0 million deferred tax asset related to the Company s pension plans. The net deferred tax asset relating to the Company s accumulated other comprehensive loss balance as of December 31, 2009 was comprised of a $9.6 million deferred tax liability related to the Company s net unrealized gain from hedging transactions, a $2.2 million deferred tax liability related to the unrealized gain on available-for-sale securities, a $7.7 million deferred tax asset related to other post-retirement benefits and a $14.7 million deferred tax asset related to the Company s pension plans.

The Company also has a deferred tax asset related to the net operating loss carryforward created in 2010 of $251.4 million and 2008 of $2.2 million. The federal net operating loss carryforward period is 20 years and, if unused, the loss carryforward for 2008 and 2010 will expire in 2028 and 2030, respectively.

The Company is subject to the alternative minimum tax (AMT) if the computed AMT liability exceeds the regular tax liability for the year. As a result of certain AMT preference items related to intangible drilling costs and in connection with the 2009 net operating loss carryback, the Company has generated AMT carryforwards of $26.0 million for prior years. Since AMT taxes paid can be credited against regular tax and have an indefinite carryforward period, this item is reflected as a deferred tax asset on the Company s balance sheet.

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As of December 31, 2010, the Company has recorded a deferred tax asset of $52.2 million, which is net of valuation allowances of $3.3 million, related to tax benefits from state net operating loss carryforwards with various expiration dates ranging from 2011 to 2029. As of December 31, 2009, the Company had recorded a deferred tax asset of $31.8 million, which is net of valuation allowances of $3.6 million, related to tax benefits from state net operating loss carryforwards with various expiration dates ranging from 2011 to 2030.

An income tax benefit of approximately $1 million for each of the years ended December 31, 2009 and 2008, respectively, triggered by the exercise of nonqualified employee stock options and vesting of restricted share awards is reflected as an addition to common stockholders equity. During the year ended December 31, 2010, share-based payment arrangements paid in stock generated a $5.0 million excess tax benefit. However, due to the Company s net operating loss position, the 2010 excess tax benefit was not recorded in the financial statements as an addition to common stockholders equity.

8. Equity in Nonconsolidated Investments

The Company has ownership interests in nonconsolidated investments that are accounted for under the equity method of accounting. The following table summarizes the equity in the nonconsolidated investments:

Investees	Location	Interest Type	Ownership as of December 31, 2010	December 31, 2010	2009
				(Thousands)	
Nora Gathering, LLC (Nora LLC)	USA	Joint	50%	$ 153,345	$ 143,813
Appalachian Natural Gas Trust (ANGT)	USA	Limited	1%	37,920	38,053
Total equity in nonconsolidated investments				$ 191,265	$ 181,866

The Company s ownership share of the earnings for 2010, 2009 and 2008 related to the total investments accounted for under the equity method was $9.7 million, $6.5 million and $5.7 million, respectively.

EQT Midstream s equity investment in Nora LLC represents a 50% ownership interest which was obtained during 2007 through a series of transactions with Pine Mountain Oil and Gas, Inc., a subsidiary of Range Resources Corporation, by contributing Nora area gathering property in exchange for the ownership interest. EQT Midstream made additional equity investments in Nora LLC of $6.4 million and $29.0 million in 2009 and 2008, respectively. EQT Midstream made no additional equity investments in Nora LLC during 2010. EQT Midstream s investment in Nora LLC totaled $153.3 million and $143.8 million as of December 31, 2010 and 2009, respectively.

EQT Production s equity investment in ANGT represents an ownership interest in natural gas producing properties located in the Appalachian Basin region of the United States. As of December 31, 2010, EQT Production s investment in ANGT totaled $25.2 million while the Company s total investment was $37.9 million. As of December 31, 2009, EQT Production s investment in ANGT totaled $25.3 million, while the Company s total investment was $38.1 million. The portion of the investment not held by EQT Production is intended to fund plugging and abandonment and other liabilities for which the Company self-insures. The Company did not make any additional equity investments in ANGT during 2010 or 2009. Despite the 1% ownership percentage in ANGT, the Company determined it is appropriate to use the equity method of accounting to account for ANGT s activities because of the Company s ability to exert significant influence over the operating and financial decisions of ANGT.

The following tables summarize the unaudited condensed financial statements for nonconsolidated investments accounted for under the equity method of accounting for the periods noted:

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Summarized Balance Sheets

	As of December 31, 2010	2009
	(Thousands)	
Current assets	$ 45,493	$ 18,022
Noncurrent assets	399,447	419,484
Total assets	$ 444,940	$ 437,506
Current liabilities	$ 8,013	$ 6,350
Stockholders equity	436,927	431,156
Total liabilities and stockholders equity	$ 444,940	$ 437,506

Summarized Statements of Income

	Years Ended December 31, 2010	2009	2008
		(Thousands)	
Revenues	$ 62,618	$ 89,980	$ 140,658
Operating expenses	41,693	63,877	64,273
Net income	$ 20,925	$ 26,103	$ 76,385

9. Investments, Available-For-Sale

As of December 31, 2010, the investments classified by the Company as available-for-sale consist of approximately $29.0 million of equity and bond funds intended to fund plugging and abandonment and other liabilities for which the Company self-insures.

	December 31, 2010 Adjusted Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(Thousands)		
Equity funds	$ 19,862	$ 7,362	$	$ 27,224
Bond funds	1,574	170		1,744
Total investments	$ 21,436	$ 7,532	$	$ 28,968

	December 31, 2009			
	Adjusted Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(Thousands)			
Equity funds	$ 22,272	$ 5,697	$	$ 27,969
Bond funds	7,592	595		8,187
Total investments	$ 29,864	$ 6,292	$	$ 36,156

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During 2010 and 2009, the Company purchased additional securities with a cost basis totaling $0.8 million and $3.0 million, respectively. These investments are classified as available-for-sale in the Consolidated Balance Sheets.

During 2010, the Company sold available-for-sale securities for $12.3 million which resulted in gross realized gains of $2.1 million, $1.4 million of which was reclassified from accumulated other comprehensive income.

10. Regulatory Assets

The following table summarizes the Company s regulatory assets, net of amortization, as of December 31, 2010 and 2009. The Company believes that it will continue to be subject to rate regulation that will provide for the recovery of its regulatory assets.

	December 31,	
Description	**2010**	**2009**
	(Thousands)	
Deferred taxes	$ 91,004	$ 89,904
Deferred purchased gas costs	12,466	27,657
Other post-retirement benefits other than pensions	7,327	8,448
CAP tracker	1,244	4,931
Other recoverable costs	2,618	792
Total regulatory assets	114,659	131,732
Amounts classified as other current assets	13,710	32,588
Total long-term regulatory assets	$ 100,949	$ 99,144

The regulatory asset associated with deferred taxes primarily represents deferred income taxes recoverable through future rates once the taxes become current. The Company expects to recover the amortization of this asset through rates. Deferred purchased gas costs and CAP tracker are included in prepaid expenses and other in the Consolidated Balance Sheets.

The Company amortizes post-retirement benefits other than pensions previously deferred and recognizes expenses for on-going post-retirement benefits other than pensions, both of which are subject to recovery in approved rates. The reduction in the Company s regulatory asset for amortization of post-retirement benefits other than pensions previously deferred was approximately $0.7 million and $1.4 million for the years ended December 31, 2010 and 2009, respectively. The $7.3 million regulatory asset related to other post-retirement benefits other than pensions recorded as of December 31, 2010 is expected to be recovered in rates within approximately 6 years.

The regulatory assets for deferred taxes and other post-retirement benefits do not earn a return on investment.

11. Short-Term Loans

On December 8, 2010, the Company entered into a $1.5 billion four-year revolving credit agreement, which replaced the Company s previous $1.5 billion five-year revolving credit agreement. The Company may request two one-year extensions of the December 8, 2014 stated maturity date; however, these extensions require the approval of greater than 50% of the lenders underwriting the credit facility. Any such extension shall only apply to the lenders who consent to the extension and any lender who replaces a non-consenting lender pursuant to the terms of the credit agreement. The revolving credit agreement may be used for working capital, capital expenditures, share repurchases and other purposes including support of a commercial paper program. Subject to certain terms and conditions, the Company may, on a one time basis, request that the lenders commitments be increased to an aggregate amount of up to $2.0 billion. Each lender in the facility may decide if it will increase its commitment.

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The credit facility is underwritten by a syndicate of 20 financial institutions each of which is obligated to fund its pro-rata portion of any borrowings by the Company.

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

As of December 31, 2010, the Company had outstanding under the revolving credit facility loans of $53.7 million and an irrevocable standby letter of credit of $23.5 million. As of December 31, 2009, the Company had outstanding loans under the previous revolving credit facility of $5.0 million and an irrevocable standby letter of credit of $24.4 million. Commitment fees averaging approximately one-twelfth of one percent in 2010 and 2009 were paid to maintain credit availability under the applicable revolving credit facility.

The weighted average interest rates for short-term loans outstanding as of December 31, 2010 and 2009 were 1.81% and 0.51%, respectively. The maximum amount of outstanding short-term loans at any time during the year was $139.7 million in 2010 and $448.9 million in 2009. The average daily balance of short-term loans outstanding over the course of the year was approximately $24.9 million and $116.8 million at weighted average annual interest rates of 0.70% and 0.73% during 2010 and 2009, respectively.

The Company s debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. The most significant default events include maintaining covenants with respect to maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company s current credit facility s financial covenants require a total debt-to-total capitalization ratio of no greater than 65%. The calculation of this ratio excludes the effects of accumulated other comprehensive income (loss). As of December 31, 2010, the Company is in compliance with all existing debt provisions and covenants.

12. Long-Term Debt

	December 31,	
	2010	**2009**
	(Thousands)	
5.15% notes, due November 15, 2012	$ 200,000	$ 200,000
5.00% notes, due October 1, 2015	150,000	150,000
5.15% notes, due March 1, 2018	200,000	200,000

6.50% notes, due April 1, 2018	500,000	500,000
8.13% notes, due June 1, 2019	700,000	700,000
7.75% debentures, due July 15, 2026	115,000	115,000
Medium-term notes:		
8.5% to 9.0% Series A, due 2011 thru 2021	46,200	46,200
7.3% to 7.6% Series B, due 2013 thru 2023	30,000	30,000
7.6% Series C, due 2018	8,000	8,000
	1,949,200	1,949,200
Less debt payable within one year	6,000	
Total long-term debt	$ 1,943,200	$ 1,949,200

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

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Aggregate maturities of long-term debt are $6.0 million in 2011, $200.0 million in 2012, $10.0 million in 2013, $5.0 million in 2014 and $160.0 million in 2015.

13. Pension and Other Post-retirement Benefit Plans

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

	For the Years Ended December 31,			
	2010	2009	2010	2009
	Pension Benefits		Other Benefits	
	(Thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 63,801	$ 72,330	$ 37,423	$ 42,702
Service cost	600	435	616	575
Interest cost	3,390	3,624	1,974	2,148
Actuarial loss (gain)	1,545	157	(898)	(3,517)
Benefits paid	(6,053)	(6,346)	(4,409)	(4,485)
Expenses paid	(599)	(512)		
Settlements	(1,236)	(6,176)		
Special termination benefits	4	289		
Benefit obligation at end of year	$ 61,452	$ 63,801	$ 34,706	$ 37,423
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 48,998	$ 40,803	$	$
Actual gain on plan assets	5,719	9,676		
Contributions	1,254	11,553		
Benefits paid	(6,053)	(6,346)		
Expenses paid	(599)	(512)		
Settlements	(1,236)	(6,176)		
Fair value of plan assets at end of year	$ 48,083	$ 48,998	$	$
Funded status at end of year	$ (13,369)	$ (14,803)	$ (34,706)	$ (37,423)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$ (2)	$ (305)	$ (3,938)	$ (4,306)
Noncurrent liabilities	(13,367)	(14,498)	(30,768)	(33,117)
Net amount recognized	$ (13,369)	$ (14,803)	$ (34,706)	$ (37,423)

Amounts recognized in accumulated other comprehensive income (loss), net of tax, consist of:				
Net loss	$ 20,995	$ 22,051	$ 13,616	$ 14,862
Net prior service cost (credit)			(2,805)	(3,086)
Net amount recognized	$ 20,995	$ 22,051	$ 10,811	$ 11,776

The accumulated benefit obligation for all defined benefit pension plans was $61.5 million and $63.8 million at December 31, 2010 and 2009, respectively. The Company uses a December 31 measurement date for its defined benefit pension and other post-retirement plans.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010

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

	For the Years Ended December 31,					
	2010	2009	2008	2010	2009	2008
	Pension Benefits			Other Benefits		
	(Thousands)					
Components of net periodic benefit cost:						
Service cost	$ 600	$ 435	$ 176	$ 616	$ 575	$ 441
Interest cost	3,390	3,624	4,321	1,974	2,148	2,438
Expected return on plan assets	(4,289)	(4,578)	(5,333)			
Amortization of prior service cost		16	116	(902)	(902)	(902)
Recognized net actuarial loss	1,323	1,191	1,249	1,652	1,797	2,043
Settlement loss and special termination benefits	569	838	9,019			17
Curtailment loss		39	337			961
Net periodic benefit cost	$ 1,593	$ 1,565	$ 9,885	$ 3,340	$ 3,618	$ 4,998

Under the current Equitrans rate case settlement, the Company began amortization of post-retirement benefits other than pensions previously deferred as well as recognizing expenses for on-going post-retirement benefits other than pensions, which are now subject to recovery in the approved rates. Expenses recognized by the Company for amortization of post-retirement benefits other than pensions previously deferred were approximately $0.7 million, $1.4 million and $1.2 million, respectively, for the years ended December 31, 2010, 2009 and 2008.

	For the Years Ended December 31,					
	2010	2009	2008	2010	2009	2008
	Pension Benefits			Other Benefits		
	(Thousands)					
Other changes in plan assets and benefit obligations recognized in other comprehensive income (loss), net of tax:						
Net (gain) loss	$ (1,056)	$ (4,006)	$ 11,501	$ (1,246)	$ (2,124)	$ 1,615
Net prior service (credit) cost		(33)	(272)	281	472	314
Total recognized in other comprehensive income (loss), net of tax	(1,056)	(4,039)	11,229	(965)	(1,652)	1,929
Total recognized in net periodic benefit cost and other comprehensive income (loss), net of tax	$ 537	$ (2,474)	$ 21,114	$ 2,375	$ 1,966	$ 6,927

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive income (loss), net of tax, into net periodic benefit cost over the next fiscal year is $0.9 million. The estimated net loss and net prior service credit for the other post-retirement benefit plans that will be amortized from accumulated other comprehensive income (loss), net of tax, into net periodic benefit cost over the next fiscal year are $0.9 million and $(0.5) million.

The following weighted average assumptions were used to determine the benefit obligations for the Company s defined benefit pension and other post-retirement benefit plans at December 31:

	For the Years Ended December 31,			
	2010	2009	2010	2009
	Pension Benefits		Other Benefits	
Discount rate	5.50%	5.75%	5.50%	5.75%
Rate of compensation increase	N/A	N/A	N/A	N/A

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010

The following weighted average assumptions were used to determine the net periodic benefit cost for the Company s defined benefit pension and other post-retirement benefit plans for the years ended December 31:

	For the Years Ended December 31,			
	2010	2009	2010	2009
	Pension Benefits		Other Benefits	
Discount rate	5.75%	5.75%	5.75%	5.75%
Expected return on plan assets	8.00%	8.00%	N/A	N/A
Rate of compensation increase	N/A	N/A	N/A	N/A

The expected rate of return is established at the beginning of the fiscal year to which it relates based upon information available to the Company at that time, including the plans investment mix and the forecasted rates of return on the types of securities held. The Company considered the historical rates of return earned on plan assets, an expected return percentage by asset class based upon a survey of investment managers and the Company s actual and targeted investment mix. Any differences between actual experience and assumed experience are deferred as an unrecognized actuarial gain or loss. The unrecognized actuarial gains or losses are amortized into the Company s net periodic benefit cost. The expected rate of return determined as of January 1, 2011 is 8.00%. This assumption will be used to derive the Company s 2011 net periodic benefit cost. The rate of compensation increase is not applicable in determining future benefit obligations as a result of plan design. Pension expense increases as the expected rate of return decreases or if the discount rate is lowered.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits in 2011 is 8.50% for both the Pre-65 and Post-65 medical charges. The rates were assumed to decrease gradually to ultimate rates of 5.00% in 2018.

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

	One-Percentage-Point Increase			One-Percentage-Point Decrease		
	2010	2009	2008	2010	2009	2008
	Pension Benefits			Other Benefits		
	(Thousands)					
Increase (decrease) to total of service and interest cost components	$ 47	$ 52	$ 50	$ (46)	$ (51)	$ (49)
Increase (decrease) to post-retirement benefit obligation	$ 756	$ 836	$ 1,064	$ (723)	$ (795)	$ (1,007)

The Company s pension asset allocation at December 31, 2010 and 2009 and target allocation for 2011 by asset category are as follows:

Asset Category	Target Allocation 2011	Percentage of Plan Assets at December 31, 2010	2009
Domestic broadly diversified equity securities	40% - 60%	46%	47%
Fixed income securities and inflation hedge securities	20% - 60%	34%	37%
International broadly diversified equity securities	5% - 15%	14%	12%
Other	0% - 15%	6%	4%
		100%	100%

The investment activities of the Company s pension plan are supervised and monitored by the Benefits Investment Committee (BIC). The BIC reports to the Compensation Committee of the Board of Directors and is

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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comprised of the Chief Financial Officer and other officers and employees of the Company. The BIC has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals of the BIC are to minimize high levels of risk at the total pension investment fund level. The BIC monitors the asset allocation on a quarterly basis and adjustments are made, as needed, to rebalance the assets within the prescribed target ranges. Comparative market and peer group benchmarks are utilized to ensure that each of the firm s investment managers is performing satisfactorily.

The Company made cash contributions of approximately $1.3 million, $11.6 million and $3.4 million to its pension plan during 2010, 2009 and 2008, respectively, as a result of the Kentucky West Virginia Gas Company LLC settlements described below as well as additional contributions to meet certain funding targets. The Company expects to make cash payments of at least $5.9 million related to its pensions during 2011, which will meet the 80% funding obligation on its plan. Pension plan cash contributions are designed to at least meet requirements of the 80% funding level. The dollar amount of a cash contribution made in any particular year will vary as a result of gains or losses sustained by the pension plan during the year due to market conditions. The Company does not expect these variations to have a significant affect on its financial position, results of operations or liquidity of the Company.

The following pension benefit payments, which reflect expected future service, are expected to be paid by the plan during each of the next five years and the five years thereafter: $6.7 million in 2011; $6.4 million in 2012; $6.2 million in 2013; $6.4 million in 2014; $5.6 million in 2015; and $25.2 million in the five years thereafter.

The following benefit payments for post-retirement benefits other than pensions, which reflect expected future service, are expected to be paid by the Company during each of the next five years and the five years thereafter: $4.0 million in 2011; $3.9 million in 2012; $3.8 million in 2013; $3.7 million in 2014; and $3.5 million in 2015; and $15.8 million in the five years thereafter.

Expense recognized by the Company related to its 401(k) employee savings plans totaled $10.4 million in 2010, $10.1 million in 2009 and $8.8 million in 2008.

During 2008, the Company settled its pension obligations under a plan covering employees of the former Kentucky West Virginia Gas Company LLC (Kentucky West Virginia), an EQT subsidiary which merged into EQT Gathering LLC. The former Kentucky West Virginia employees transferred to EQT Gathering LLC or EQT Production Company. As a result of the settlement, the Company recognized settlement expense of approximately $9.0 million, comprised of $8.0 million for pension benefits and $1.0 for other post-retirement benefits, for an early retirement program. Under this settlement, the affected employees were provided the option either to roll over to the Company s defined contribution plan the lump-sum value of their pension benefit or to receive an insured annuity benefit. The $9.0 million settlement expense was recorded as operating and maintenance expense included within operating expenses of the EQT Midstream business segment. As a result of this settlement, the Company s projected benefit obligation decreased by approximately $3.9 million.

The Company adopted amendments to Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) Topic 715, Compensation Retirement Benefits effective December 31, 2009. The disclosures required by this guidance are intended to enhance the transparency surrounding the types of assets and associated risks in an employer s defined benefit pension or other post-retirement plan. The disclosures define fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The disclosure fair value hierarchy requires assets and liabilities measured at fair value to be categorized into one of three levels used in the valuation. Assets and liabilities are classified in their entirety based on the lowest level of input significant to the fair value measurement. The three levels are defined as follows:

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

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

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

Investments in the plan assets include mutual funds totaling $19.1 million and $19.9 million, which are stated at fair value as of December 31, 2010 and December 31, 2009, respectively. These investments are based upon daily unadjusted quoted prices and therefore are considered Level 1.

Investments in the plan assets include common/collective trusts totaling $29.0 million and $29.1 million, which are stated at fair value as of December 31, 2010 and December 31, 2009, respectively. These investments are valued at current market value of the underlying assets of the fund and therefore are considered Level 2.

As of December 31, 2010 and December 31, 2009, the plan does not hold any assets whose fair value is determined using unobservable inputs and therefore would be considered Level 3.

14. Common Stock and Earnings Per Share

At December 31, 2010, shares of EQT s authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	20,457
Stock compensation plans	7,218
Total	27,675

Earnings Per Share

The computation of basic and diluted earnings per common share is shown in the table below:

	Years Ended December 31,		
	2010	2009	2008
	(Thousands except per share amounts)		
Basic earnings per common share:			
Net income	$ 227,700	$ 156,929	$ 255,604
Average common shares outstanding	144,458	130,820	127,234
Basic earnings per common share	$ 1.58	$ 1.20	$ 2.01
Diluted earnings per common share:			
Net income	$ 227,700	$ 156,929	$ 255,604
Average common shares outstanding	144,458	130,820	127,234
Potentially dilutive securities:			
Stock options and awards (a)	774	662	872
Total	145,232	131,482	128,106
Diluted earnings per common share	$ 1.57	$ 1.19	$ 2.00

(a) Options to purchase 1,229,109, 955,107 and 6,480 shares of common stock were not included in the computation of diluted earnings per common share for 2010, 2009 and 2008, respectively, because the options exercise prices were greater than the average market prices of the common shares.

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15. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive income (loss), net of tax, are as follows:

	December 31, 2010	December 31, 2009
	(Thousands)	
Net unrealized gain from hedging transactions	$ 65,014	$ 15,297
Unrealized gain on available-for-sale securities	4,896	4,090
Pension and other post-retirement benefits liability adjustment	(31,806)	(33,827)
Accumulated other comprehensive income (loss)	$ 38,104	$ (14,440)

16. Share-Based Compensation Plans

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

	Years Ended December 31, 2010	2009	2008
		(Thousands)	
2005 Executive Performance Incentive Program	$	$	$ (41,778)
2008 Executive Performance Incentive Program	316	770	496
2010 Executive Performance Incentive Programs	2,905		
2009 Shareholder Value Plan		45,097	
2007 Supply Long-Term Incentive Program	6,763	8,652	2,426
2010 Stock Incentive Award Program	4,134		
Restricted stock awards	3,020	3,634	5,394
Non-qualified stock options	4,045	3,134	1,306
Non-employee directors share-based awards	1,196	557	(958)
Total share-based compensation expense (income)	$ 22,379	$ 61,844	$ (33,114)

The Company typically uses treasury stock to fund awards that are paid in stock. When an award has graduated vesting, the Company records the expense equal to the vesting percentage on the vesting date. A portion of the expense related to share-based compensation plans is included as an unallocated expense in deriving total operating income for segment reporting purposes. See Note 2.

Cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2010, 2009 and 2008, was $2.2 million, $0.8 million and $0.9 million, respectively. The actual tax benefits realized for tax deductions, including excess tax benefits, from share-based payment arrangements which were paid in stock for the years ended December 31, 2009 and 2008 was $2.2 million and $2.2 million, respectively. During the year ended December 31, 2010, share-based payment arrangements paid in stock generated a $6.0 million tax benefit. However, due to the Company s net operating loss position, the 2010 excess tax benefit of $5.0 million was not recorded in the financial statements as an addition to common stockholders equity. For share-based payment arrangements paid in cash, the Company recognizes tax benefits at the effective tax rate, except as limited by Section 162(m) of the IRC as discussed in Note 7.

Executive Performance Incentive Programs

In February 2005, the Compensation Committee of the Board of Directors adopted the 2005 Executive Performance Incentive Program (2005 Program) under the 1999 Long-Term Incentive Plan. The 2005 Program was established to provide additional incentive benefits to retain executive officers and certain other employees of the Company in order to further align the interests of the persons primarily responsible for the success of the Company with the interests of the shareholders. The vesting of the stock units granted under the 2005 Program occurred on December

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31, 2008, after the ordinary close of the performance period. The vesting resulted in approximately 1.9 million units (175% of the award) with a value of approximately $64 million being distributed in cash and stock on December 31, 2008. Greater than 90% of the award was distributed in cash. The Company accounted for these awards as liability awards and as such recorded compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. The Company recorded a reversal of previously recorded compensation expense in 2008 primarily due to the reduction in the Company s stock price during the year.

In 2008, the Compensation Committee of the Board of Directors adopted the 2008 Executive Performance Incentive Program (2008 Program) under the 1999 Long-Term Incentive Plan. The 2008 Program was established to provide additional long-term incentive opportunities to key executives to further align their interests with those of the Company s shareholders and with the strategic objectives of the Company. A total of 68,860 units were granted and no additional units may be granted. The vesting of these units will occur upon payment after the end of the performance period at a payout multiple dependent upon the level of total shareholder return relative to a predefined peer group s total shareholder return during the 3.5 year performance period. As a result, zero to approximately 210,000 units (reflecting a 300% payout multiple) may be distributed upon vesting. The Compensation Committee of the Board of Directors retained the discretion to reduce the payout multiple by a specified amount if the Company does not attain a specified revenue target. However, if the Company s total shareholder return ranking is median or above, the payout multiple may not be decreased below 100%. Payment of awards is expected to be made in cash based on the price of the Company s common stock at the end of the performance period, December 31, 2011. The Company accounts for these awards as liability awards and as such records compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. The Company continually monitors its stock price and performance in order to assess the impact on the ultimate payout under the 2008 Program. The Company s current assumptions for the ultimate share price and payout multiple are $50 and 75% of the units awarded, respectively. As of December 31, 2010, approximately 57,520 units were outstanding under the 2008 Program. The 2008 Program expense is classified as selling, general and administrative expense in the Statements of Consolidated Income.

The peer companies for the 2008 Program are as follows:

Atlas Energy Resources, LLC	Markwest Energy Partners, L.P.	Sempra Energy
Cabot Oil & Gas Corp.	MDU Resources Group Inc.	Southern Union Co.
Chesapeake Energy Corp.	National Fuel Gas Co.	Southwestern Energy Co.
CNX Gas Corp.	ONEOK, Inc.	Spectra Energy Corp.
El Paso Corp.	Penn Virginia Corp.	TransCanada Corp.
Enbridge Inc.	Questar Corp.	The Williams Companies, Inc.
Energen Corp.	Range Resources Corp.	

In 2009, the Compensation Committee of the Board of Directors adopted the 2010 Executive Performance Incentive Plan (2010 Program) under the 2009 Long-Term Incentive Plan. The 2010 Program was established to provide additional long-term incentive opportunities to key employees to further align their interests with those of the Company s shareholders and with the strategic objectives of the Company. A total of 161,940 units were granted and no additional units may be granted. The vesting of the units under the 2010 Program will occur upon payment after the end of the 3-year performance period. The payment will vary between zero and 300% of the number of units granted contingent upon a combination of the level of total shareholder return relative to a predefined peer group over the period January 1, 2010 through December 31, 2012 and the level of production sales revenues over the period January 1, 2010 through September 30, 2012. If earned, the 2010 Program units are expected to be distributed in Company common stock. The Company accounted for these awards as equity awards using the $60.09 grant date fair value as determined using a Monte Carlo simulation. The Monte Carlo simulation projected the share price, for the Company and its peers, at the ending point of the performance period. The prices were generated using each company s annual volatility for the expected term and the commensurate 3-year risk-free rate of 1.69%.

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The peer companies for the 2010 Program are as follows:

Cabot Oil & Gas Corp.	Markwest Energy Partners, L.P.	REX Energy Corp.
Chesapeake Energy Corp.	MDU Resources Group Inc.	Sempra Energy
CNX Gas Corp.	National Fuel Gas Co.	Southern Union Co.
El Paso Corp.	ONEOK, Inc.	Southwestern Energy Co.
Enbridge Inc.	Penn Virginia Corp.	Spectra Energy Corp.
Energen Corp.	Petroleum Development Corp.	TransCanada Corp.
EOG Resources, Inc.	Questar Corp.	The Williams Companies, Inc.
EXCO Resources, Inc.	Range Resources Corp.	XTO Energy, Inc.

2009 Shareholder Value Plan

In December 2008, the Compensation Committee of the Board of Directors adopted the 2009 Shareholder Value Plan (SVP) under the 1999 Long-Term Incentive Plan. The SVP was established to ensure continued alignment with shareholders, to recognize the Company s evolution from a diversified utility to an integrated energy company and to continue to encourage sustained high performance and shareholder return. The effective date of the SVP was January 1, 2009. The vesting of the stock units granted under the 2009 SVP occurred on December 31, 2009, after the ordinary close of the performance period. The vesting resulted in approximately 2.2 million units (225% of the award) with a value of approximately $45 million being distributed in cash on December 31, 2009. The Company accounted for these awards as liability awards and as such recorded compensation expense for the fair value of the awards at the end of each reporting period.

2007 Supply Long-Term Incentive Program

Effective July 1, 2007, the Compensation Committee of the Board of Directors established the 2007 Supply Long-Term Incentive Program (2007 Supply Program) to provide a long-term incentive compensation opportunity to key employees in the EQT Production and EQT Midstream segments. Awards granted were earned by achieving pre-determined total sales and efficiency targets and by satisfying certain applicable employment requirements. The awards earned were increased to a maximum of three times the initial award based upon achievement of the predetermined performance levels. Payment of awards will be made in cash based on the price of the Company s common stock at the end of the performance period, December 31, 2010. The Company accounts for these awards as liability awards and as such recorded compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. In the first quarter of 2010 and 2009, the Company granted approximately 10,000 and 116,000, respectively, of additional awards to key employees in the EQT Production and EQT Midstream segments. As of December 31, 2010, before application of the performance multiplier, approximately 265,850 of the awards were outstanding under this program. The ultimate share price at the vesting date for the 2007 Supply Program is $44.87. Total compensation cost recorded for the 2007 Supply Program was $10.8 million for the year ended December 31, 2010, which included $4.0 million of cost capitalized as part of oil and gas-producing properties and $6.8 million recorded as expense in the Company s Consolidated Statements of Income.

2010 Stock Incentive Award

Effective in 2010, the Compensation Committee of the Board of Directors adopted the 2010 Stock Incentive Award program (2010 SIA) under the 2009 Long-Term Incentive Plan. The 2010 SIA was established to provide additional long-term incentive opportunities to key employees to further align their interests with those of the Company s shareholders and with the strategic objectives of the Company. A total of 155,850 target performance awards were initially granted under the 2010 SIA. The vesting of the awards under the 2010 SIA will occur on the third anniversary of the grant date. The payout opportunity with respect to the target performance awards was contingent upon adjusted 2010 earnings before interest, taxes, depreciation and amortization (EBITDA) performance as compared to plan and individual, business unit and Company value driver performance over the period January 1, 2010 through December 31, 2010. Adjusting for the performance multiplier and forfeitures, as of February 2, 2011, there were 302,355 confirmed performance awards outstanding under the 2010 SIA which are expected to be distributed in Company common stock.

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Restricted Stock Awards

The Company granted 85,720, 62,340 and 157,730 restricted stock awards during the years ended December 31, 2010, 2009 and 2008, respectively, to key employees of the Company. The majority of the shares granted will be fully vested at the end of the three-year period commencing with the date of grant. The weighted average fair value of these restricted stock grants, based on the grant date fair value of the Company s stock, was approximately $43, $33 and $59 for the years ended December 31, 2010, 2009 and 2008, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2010, 2009, and 2008 was $2.9 million, $6.0 million and $3.7 million, respectively.

As of December 31, 2010, there was $3.7 million of total unrecognized compensation cost related to nonvested restricted stock awards. That cost is expected to be recognized over a remaining weighted average vesting term of approximately 9 months.

A summary of restricted stock activity as of December 31, 2010, and changes during the year then ended, is presented below:

Restricted Stock	Non-Vested Shares	Weighted Average Fair Value	Weighted Average Remaining Contractual Term (months)	Aggregate Fair Value
Outstanding at January 1, 2010	227,110	$ 46.13		$ 10,476,190
Granted	85,720	$ 42.90		3,677,051
Vested	(64,890)	$ 44.92		(2,914,825)
Forfeited	(16,040)	$ 46.91		(752,411)
Outstanding at December 31, 2010	231,900	$ 45.22	9	$ 10,486,005

Non-Qualified Stock Options

The fair value of the Company s option grants was estimated at the dates of grant using a Black-Scholes option-pricing model with the assumptions indicated in the table below for the years ended December 31, 2010, 2009 and 2008. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the historical dividend yield of the Company s stock. Expected volatilities are based on historical volatility of the Company s stock. The expected term of options granted represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

	Years Ended December 31,		
	2010	**2009**	**2008**
Risk-free interest rate	1.60% - 2.50%	N/A	3.28%
Dividend yield	2.10% - 2.34%	N/A	1.51%
Volatility factor	.28	N/A	.22
Expected term	5 years	N/A	5 years

The Company granted 409,100 and 905,700 stock options during the years ended December 31, 2010 and 2008, respectively. The weighted average grant date fair value of the options was $9.31 and $10.32 for the years ended

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December 31, 2010 and 2008, respectively. The total intrinsic value of options exercised during the years ended December 31, 2010, 2009 and 2008 was $7.5 million, $1.6 million and $2.3 million, respectively. No options were granted in 2009.

As of December 31, 2010, there was $4.6 million of total unrecognized compensation cost related to outstanding nonvested stock options which will be recognized over the next 3 years.

A summary of option activity as of December 31, 2010, and changes during the year then ended, is presented below:

Non-qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2010	2,393,173	$ 28.86		
Granted	409,100	$ 42.91		
Exercised	(503,297)	$ 14.80		
Forfeited	(16,700)	$ 48.91		
Outstanding at December 31, 2010	2,282,276	$ 34.31	4.0 years	$ 27,681,429
Exercisable at December 31, 2010	1,860,976	$ 31.67	2.9 years	$ 27,286,267

Non-employee Directors Share-Based Awards

At December 31, 2010, 45,600 options were outstanding and included in the table above under the 1999 Non-employee Directors Stock Incentive Plan at prices ranging from $18.12 to $19.56 per share. The exercise price for each award is equal to the market price of the Company s common stock on the date of grant. Each option is subject to time-based vesting provisions and expires 5 to 10 years after date of grant. No options have been granted to non-employee directors since 2002 and all previously granted options are vested.

The Company has also historically granted to non-employee directors share-based awards which vest upon award. The value of the share-based awards will be paid in cash on the earlier of the director s death or retirement from the Company s Board of Directors. The Company accounts for these awards as liability awards and as such records compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. A total of 125,891 non-employee director share based awards were outstanding as of December 31, 2010. A total of

28,348, 23,760 and 12,800 share based awards were granted to non-employee directors during the years ended December 31, 2010, 2009 and 2008, respectively. The weighted average fair value of these grants, based on the grant date fair value of the Company s stock, was $38.74, $41.68 and $68.22 for the years ended December 31, 2010, 2009 and 2008, respectively.

2011 Volume and Efficiency Program and 2011 Value Driver Award program

Effective 2011, the Compensation Committee of the Board of Directors adopted the 2011 Volume and Efficiency Program (2011 VEP) and the 2011 Value Driver Award program (2011 VDA) under the 2009 Long-Term Incentive Plan. The 2011 VEP and 2011 VDA were established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. The effective dates of the 2011 VEP and 2011 VDA were in 2011, and as such, the Company has not recorded an obligation or expense related to the 2011 VEP or 2011 VDA at December 31, 2010.

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The awards granted under the 2011 VEP may be increased to a maximum of three times the initial award based on the achievement of predetermined specified performance measures. Payment of the awards is expected to be distributed in Company stock at the end of the performance period, December 31, 2013.

50% of the units awarded under the 2011 VDA will vest upon the payment date following the first anniversary of the grant date; the remaining 50% of the units awarded under the 2011 VDA will vest upon the payment date following the second anniversary of the grant date. The payment will vary between zero and 300% of the number of units granted contingent upon adjusted 2011 earnings before interest, taxes, depreciation and amortization (EBITDA) performance as compared to plan and individual, business unit and Company value driver performance over the period January 1, 2011 through December 31, 2011. If earned, the 2011 VDA units are expected be paid in cash.

2011 Stock Options

Effective January 1, 2011, the Compensation Committee of the Board of Directors approved the grant of 229,100 non-qualified stock options to key employees of the Company. The 2011 options are seven-year options, with an exercise price of $44.84, and a vesting schedule as follows: 50% vest on January 1, 2012, and 50% vest on January 1, 2013, contingent upon continued employment with the Company on such dates. The Company has not recorded any obligation or expense related to 2011 Stock Options as of December 31, 2010.

17. Concentrations of Credit Risk

Revenues and related accounts receivable from the EQT Production segment s operations are generated primarily from the sale of produced natural gas, NGLs and limited amounts of crude oil to certain marketers, EQT Energy, LLC (an affiliate), other Appalachian Basin purchasers and utility and industrial customers located mainly in the Appalachian area. No customers accounted for more than 10% of revenues in 2010 or 2009. As of December 31, 2008, sales to one marketer accounted for approximately 13% of revenues for EQT Production. EQT Midstream s gathering revenues include the gathering of natural gas in Kentucky, Virginia, Pennsylvania and West Virginia.

The transmission and storage operations of EQT Midstream include FERC regulated interstate pipeline transportation and storage service for the Distribution segment, as well as other utility and end user customers located in the northeastern United States. These operations also provide commodity procurement and delivery, physical natural gas management operations and control and customer support services to energy consumers including large industrial, utility, commercial, institutional and certain marketers primarily in the Appalachian and mid-Atlantic regions.

Distribution s operating revenues and related accounts receivable are generated primarily from state-regulated distribution natural gas sales and transportation to approximately 276,500 residential, commercial and industrial customers located in southwestern Pennsylvania, northern West Virginia and eastern Kentucky. Distribution continues to aggressively monitor and analyze various customer-related metrics and their impact on accounts receivable. The Company employs a firm collections strategy which is comprised of various collections tactics including outreach to low income customers to provide information regarding energy assistance programs and, if necessary, termination of service. The outreach to low income customers includes enrolling customers into the Customer Assistance Program which is an affordable payment plan for low income customers based on a percentage of total household income. This program is managed by the Company and recovered through rates charged to other residential customers.

Approximately 66% and 60% of the Company s accounts receivable balance as of December 31, 2010 and 2009, respectively, represent amounts due from marketers. The Company manages the credit risk of sales to marketers by limiting its dealings to those marketers who meet the Company s criteria for credit and liquidity strength and by actively monitoring these accounts. The Company may require letters of credit, guarantees, performance bonds or other credit enhancements from a marketer in order for that marketer to meet the Company s

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credit criteria. As a result, the Company did not experience any significant defaults on sales of natural gas to marketers during the years ended December 31, 2010, 2009 and 2008.

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value. The Company believes that NYMEX-traded future contracts have minimal credit risk because Commodity Futures Trading Commission regulations are in place to protect exchange participants, including the Company, from any potential financial instability of the exchange members. The Company s swap, collar and option derivative instruments are primarily with financial institutions and thus are subject to events that would impact those companies individually as well as that industry as a whole.

The Company utilizes various processes and analysis to monitor and evaluate its credit risk exposure to financial counter-parties. This includes closely monitoring current market conditions, counterparty credit spreads and credit default swap rates. Credit exposure is controlled through credit approvals and limits. To manage the level of credit risk, the Company deals with financial counterparties that are of investment grade or better, enters into netting agreements whenever possible and may obtain collateral or other security.

In September 2008, the credit support provider of one counterparty (Lehman Brothers) declared bankruptcy resulting in the default under various derivative contracts with the Company. As a result, those contracts were terminated and a reserve of approximately $5.0 million was recorded against the entire balance due to the Company. There is no additional income statement exposure to Lehman Brothers beyond the reserve recorded in 2008. As of December 31, 2010, the Company is not in default under any derivative contracts and has no knowledge of default by any other counterparty to derivative contracts. The Company will continue to monitor market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

As of December 31, 2010, approximately 12% of the Company s workforce is subject to collective bargaining agreements, and the collective bargaining agreement which covers approximately 9% of the Company s workforce is scheduled to expire during September 2011.

18. Commitments and Contingencies

The Company has commitments for demand charges under existing long-term contracts and binding precedent agreements with various pipelines. Future payments for these items as of December 31, 2010 totaled $1,608.6 million (2011 - $66.6 million, 2012 - $158.1 million, 2013 - $135.2 million, 2014 - $112.1 million, 2015 - $111.5 million and thereafter - $1,025.1 million). The Company believes that approximately $17.0 and $13.7 million of these demand charges payable in 2011 and 2012, respectively, are recoverable in customer rates.

The Company has agreements with Highlands Drilling, LLC, Patterson UTI Drilling Company, LLC and other drilling contractors to provide drilling equipment and services to the Company. These obligations totaled approximately $52.8 million as of December 31, 2010. Operating lease rentals for drilling contractors, office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately $97.4 in 2010, $62.3 million in 2009 and $40.4 million in 2008. Future lease payments under non-cancelable operating leases as of December 31, 2010 totaled $171.7 million (2011 - $28.4 million, 2012 - $23.0 million, 2013 - $22.2 million, 2014 - $15.3 million, 2015 - $8.1 million and thereafter - $74.7 million). The Company has subleased three floors of its previous corporate headquarters building. The Company will receive future lease payments under the non-cancelable sublease totaling approximately $32.4 million (2011 - $2.2 million, 2012 - $2.2 million, 2013 - $2.2 million, 2014 - $2.2 million, 2015 - $2.2 and thereafter - $21.4 million) as of December 31, 2010.

The Company is subject to various federal, state and local environmental and environmentally related laws and regulations. These laws and regulations, which are constantly changing, can require expenditures for remediation and may in certain instances result in assessment of fines. The Company has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. The estimated costs associated with identified situations that require remedial action are accrued. However, certain costs are deferred as regulatory assets when recoverable through regulated

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rates. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material. Management believes that any such required expenditures will not be significantly different in either their nature or amount in the future and does not know of any environmental liabilities that will have a material affect on the Company s financial position, results of operations or liquidity. The Company has identified situations that require remedial action for which approximately $1.3 million is included in other credits in the Consolidated Balance Sheets as of December 31, 2010.

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company 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.

19. Guarantees

NORESCO Guarantees

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that once the energy-efficiency construction was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a period of years. The undiscounted maximum aggregate payments that may be due related to these guarantees is approximately $234 million as of December 31, 2010, extending at a decreasing amount for approximately 19 years. In addition, the Company agreed to maintain in place certain outstanding payment and performance bonds, letters of credit and other guarantee obligations supporting NORESCO s obligations under certain customer contracts, existing leases and other items with an undiscounted maximum exposure to the Company as of December 31, 2010 of approximately $40 million, of which approximately $34 million relates to bonds that were to have been terminated as of December 31, 2010 for work completed under the underlying contracts. The Company is working with NORESCO to resolve any open matters with respect to these bonds.

In exchange for the Company s agreement to maintain these guarantee obligations, the purchaser of the NORESCO business and NORESCO agreed, among other things, that NORESCO would fully perform its obligations under each underlying agreement and agreed to reimburse the Company for any loss under the guarantee obligations, provided that the purchaser s reimbursement obligation will not exceed $6 million in the aggregate and will expire on November 18, 2014. In 2008, the original purchaser of NORESCO sold its interest in NORESCO and transferred its obligations to a third-party. In connection with that event, the new owner delivered to the Company a $1 million letter of credit supporting its obligations.

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

Other Guarantees

In December 2000, the Company entered into a transaction with ANGT by which an interest in natural gas producing properties located in the Appalachian Basin region of the United States was sold. ANGT manages the assets and produces, markets, and sells the related natural gas from the properties. Appalachian NPI, LLC (ANPI) contributed cash to ANGT. The assets of ANPI, including its interest in ANGT, collateralize ANPI s debt.

The Company has a non-equity interest in a variable interest entity, Appalachian NPI, LLC (ANPI), in which EQT was not deemed to be the primary beneficiary because EQT does not have the power to direct the activities that

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most significantly impact ANPI s economic performance. Thus, ANPI is not consolidated within the Company s Consolidated Financial Statements. As of December 31, 2010, ANPI had $143.8 million of total assets and $86.1 million of total liabilities (including $66.3 million of long-term debt, including current maturities), excluding minority interest. ANPI is financed primarily through cash provided by operating activities.

The Company provided ANPI with a liquidity reserve guarantee equal to the fair market value of the assets purchased by ANPI. This guarantee is subject to certain restrictions that limit the amount of the guarantee to the calculated present value of the project s future cash flows from the preceding year-end until the termination date of the agreement. The agreement also defines events of default, use of proceeds and demand procedures. The Company receives a market-based fee for providing the guarantee. As of December 31, 2010, the maximum amount of future payments the Company could be required to make under the liquidity reserve guarantee is estimated to be approximately $31 million. The Company has not recorded a liability for this guarantee and has not modified it subsequent to issuance. The terms of this guarantee require the Company to provide a letter of credit in favor of ANPI as security for its obligations under the liquidity reserve guarantee. The amount of the letter of credit outstanding at December 31, 2010 was approximately $23.5 million and is expected to decline over time under the terms of the liquidity reserve guarantee.

20. Office Consolidation / Impairment Charges

In the third quarter of 2009, the Company completed the relocation of its corporate headquarters and other operations to downtown Pittsburgh. As a result of the relocation, the Company recorded an impairment charge of $5.2 million in selling, general and administrative expense in the Statements of Consolidated Income for 2009. This impairment related to the reduced usage of the operating lease for, and certain assets at, the Company s previous headquarters facility located on Pittsburgh s North Shore.

21. Interim Financial Information (Unaudited)

The following quarterly summary of operating results reflects variations due primarily to the seasonal nature of the Company s distribution and storage businesses and volatility of natural gas commodity prices.

	Three months ended			
	March 31	**June 30**	**September 30**	**December 31**
	(Thousands, except per share amounts)			
2010 (a)				
Operating revenues	$ 436,640	$ 257,515	$ 257,335	$ 371,218
Operating income	169,113	78,529	88,182	134,655

Net income	88,065	30,000	36,522	73,113
Earnings per share of common stock:				
Net income				
Basic	$ 0.66	$ 0.20	$ 0.24	$ 0.49
Diluted	$ 0.65	$ 0.20	$ 0.24	$ 0.49
2009 (a)				
Operating revenues	$ 469,403	$ 238,040	$ 218,357	$ 344,027
Operating income	136,136	67,514	39,932	113,209
Net income	71,993	26,645	2,909	55,382
Earnings per share of common stock:				
Net income				
Basic	$ 0.55	$ 0.20	$ 0.02	$ 0.42
Diluted	$ 0.55	$ 0.20	$ 0.02	$ 0.42

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

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22. Natural Gas Producing Activities (Unaudited)

On December 31, 2009, the Company adopted the revisions to FASB ASC Topic 932, Extractive Activities   Oil and Gas (ASC 932) which aligned the reserve calculation and disclosure requirements of ASC 932 with the requirements of Securities and Exchange Commission (SEC) rule, Modernization of Oil and Gas Reporting, which the Company also adopted. The key revisions to ASC 932 include a change in the definition of proved undeveloped reserves to allow undeveloped locations to be recorded beyond one offset location where reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. The modernization rules also suggest that five years is a reasonable timeframe to develop existing proved undeveloped locations. In addition, the new rules require that year end proved reserve volumes be computed using an unweighted average price for sales of oil and gas on the first calendar day of each month during the year.

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

Production Costs

The following table presents the costs incurred relating to natural gas and oil production activities (a):

	2010	2009	2008
		(Thousands)	
At December 31:			
Capitalized costs	$ 4,655,217	$ 3,423,068	$ 2,709,162
Accumulated depreciation and depletion	967,473	797,303	692,327
Net capitalized costs	3,687,744	$ 2,625,765	$ 2,016,835
Costs incurred for the years ended December 31:			
Property acquisition:			
Proved properties	$ 15,359	$ 6,035	$ 3,625
Unproved properties	342,372	24,941	81,879
Exploration (b)	5,105	14,909	15,950
Development	881,331	676,121	598,963

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

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

Results of Operations for Producing Activities

The following table presents the results of operations related to natural gas and oil production for the years ended December 31:

	2010	2009 (Thousands)	2008
Revenues:			
Affiliated	$ 7,371	$ 6,923	$ 19,128
Nonaffiliated	530,286	414,067	453,833
Production costs	67,414	62,978	79,858
Exploration costs	5,368	17,905	9,064
Depreciation, depletion and accretion	183,699	117,424	78,234
Income tax expense	106,847	84,620	116,206
Results of operations from producing activities (excluding corporate overhead)	$ 174,329	$ 138,063	$ 189,599

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Reserve Information

The information presented below represents estimates of proved natural gas and oil reserves prepared by Company engineers. The engineer primarily responsible for the technical aspects of the reserves audit received a bachelor s degree in Engineering from the Pennsylvania State University and has thirteen 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; production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems; the reserve roll forward between prior year reserves and current year reserves is reviewed by senior management; and the estimates of proved natural gas and oil reserves are audited by the independent consulting firm of Ryder Scott Company L.P., who is hired by the Company s management. Since 1937, Ryder Scott Company L.P. has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally.

Proved developed reserves represent only those reserves expected to be recovered from existing wells and support equipment. There were no differences between the internally prepared and externally audited estimates. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells after substantial development costs are incurred. Ryder Scott Company L.P. reviewed 100 percent of the total net gas and liquid hydrocarbon reserves attributable to the Company s interests as of December 31, 2010. Ryder Scott conducted a detailed, well by well, audit of the Company s largest properties. This audit covered 80 percent 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. The audit utilized the performance method and the analogy method. Where historical reserve or production data was definitive the performance method, which extrapolates historical data, was utilized. In other cases the analogy method, which calculates reserves based on correlations to comparable surrounding wells, was utilized. All of the Company s proved reserves are located in the United States.

	Years Ended December 31,		
	2010	**2009**	**2008**
	(Millions of Cubic Feet)		
Natural Gas			
Proved developed and undeveloped reserves:			