UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

Commission file number: 1-13283

Penn Virginia Corporation

Penn Virginia Corporation

(Exact name of registrant as specified in its charter)

Virginia	**23-1184320**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Four Radnor Corporate Center, Suite 200
100 Matsonford Road
Radnor, Pennsylvania 19087
(Address of principal executive offices)

Registrant's telephone number, including area code: **(610) 687-8900**

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

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

Title of each class	Name of exchange on which registered
Common Stock, $0.01 Par Value	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (''Exchange Act''). Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

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

Large accelerated filer ☒	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 Exchange Act). Yes ☐ No ☒

The aggregate market value of common stock held by non-affiliates of the registrant was $599,073,526 as of June 30, 2011 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including all directors and executive officers of the registrant. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 10, 2012, 45,714,191 shares of common stock of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement relating to the registrant's Annual Meeting of Shareholders, to be held on May 4, 2012, are incorporated by reference in Part III of this Form 10-K.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2011

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Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, or Exchange Act. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- the volatility of commodity prices for natural gas, natural gas liquids and oil;
- our ability to develop, explore for and replace oil and gas reserves and sustain production;
- our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations;
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of natural gas, natural gas liquids and oil;
- reductions in the borrowing base under our revolving credit facility ("Revolver");
- our ability to contract for drilling rigs, supplies and services at reasonable costs;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production at reasonable cost and to sell the production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from estimated proved oil and gas reserves;
- drilling and operating risks;
- our ability to compete effectively against other independent and major oil and natural gas companies;
- our ability to successfully monetize select assets and repay our debt;
- leasehold terms expiring before production can be established;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements;
- our ability to maintain adequate financial liquidity and to access adequate levels of capital on reasonable terms;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key technical employees;
- counterparty risk related to their ability to meet their future obligations;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters;
- uncertainties relating to general domestic and international economic and political conditions; and
- other risks set forth in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2011.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management's views only as of the date hereof. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise.

Glossary of Certain Industry Terminology

The following are abbreviations and definitions commonly used in the oil and gas industry that are used within this Annual Report on Form 10-K.

Bbl	A standard barrel of 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.
Bcf	One billion cubic feet of natural gas.
Bcfe	One billion cubic feet of natural gas equivalent with one barrel of crude oil, condensate or natural gas liquids converted to six thousand cubic feet of natural gas based on the estimated relative energy content.
BOEPD	Barrels of oil equivalent per day.
Developed acreage	Lease acreage that is allocated or assignable to producing wells or wells capable of production.
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.
Dry hole	A well found to be incapable of producing either oil or gas in sufficient commercial quantities to justify completion of the well.
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, a service well or a stratigraphic test well.
GAAP	Accounting principles generally accepted in the Unites States of America.
Gross acre or well	An acre or well in which a working interest is owned.
LIBOR	London Interbank Offered Rate.
MBbl	One thousand barrels of oil or other liquid hydrocarbons.
Mcf	One thousand cubic feet of natural gas.
Mcfe	One thousand cubic feet of natural gas equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content.
MMBbl	One million barrels of oil or other liquid hydrocarbons.
MMBtu	One million British thermal units, a measure of energy content.
MMcf	One million cubic feet of natural gas.
MMcfe	One million cubic feet of natural gas equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content.
Net acre or well	The number of gross acres or wells multiplied by the owned working interest in the gross acres or wells.
NGL	Natural gas liquid.
NYMEX	New York Mercantile Exchange.
Operator	The entity responsible for the exploration and/or production of a lease.
Productive wells	Wells that are not dry holes.

Proved reserves	Those quantities of oil and gas which, by analysis of geosciences 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 regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate.
Proved developed reserves	Proved reserves that can be expected to be recovered: (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
Proved undeveloped reserves	Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributable to any acreage for which application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir, or by other evidence using reliable technology establishing reasonable certainty.
Standardized measure	The present value, discounted at 10% per year, of estimated future cash inflows from the production of proved reserves, computed by applying prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), reduced by estimated future development and production costs, computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year (including the settlement of asset retirement obligations), based on year-end costs and assuming continuation of existing economic conditions, further reduced by estimated future income tax expenses, computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the proved oil and gas reserves, less the tax basis of the properties involved and giving effect to the tax deductions and tax credits and allowances relating to the proved oil and gas reserves.
Revenue interest	An economic interest in production of hydrocarbons from a specified property.
Royalty interest	An interest in the production of a well entitling the owner to a share of production generally free of the costs of exploration, development and production.

Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas, regardless of whether such acreage contains proved reserves.
Working interest	A cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease.

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Part I

Item 1 *Business*

General

Penn Virginia Corporation (NYSE: PVA), a Virginia corporation formed in 1882, is an independent oil and gas company engaged primarily in the exploration, development and production of natural gas and oil in various domestic onshore regions of the United States including Texas, Appalachia, the Mid-Continent and Mississippi.

Prior to June 2010, we indirectly owned partner interests in Penn Virginia Resource Partners, L.P., or PVR, a publicly traded limited partnership formed by us in 2001 that was engaged in the coal and natural resource management and natural gas midstream businesses. Our ownership interests in PVR were held principally through our general and limited partner interests in Penn Virginia GP Holdings, L.P., or PVG, a publicly traded limited partnership formed by us in 2006. In June 2010, we disposed of our remaining ownership interests in PVG and, indirectly, our interests in PVR. This divestiture completed the process of our transformation into a ''pure play'' exploration and production (E&P) company. Our Consolidated Financial Statements and Notes present our former interests in PVG as discontinued operations.

Unless the context requires otherwise, references to the ''Company,'' ''Penn Virginia,'' ''we,'' ''us'' or ''our'' in this Annual Report on Form 10-K refer to Penn Virginia Corporation and its subsidiaries.

Description of Business

Business Overview

Having completed our transformation to a ''pure play'' E&P company, we are now focusing our efforts on oil and NGL investment opportunities rather than natural gas. During 2011, we grew our oil and NGL production to 28% (37% for the 4^{th} quarter of 2011) of our total production, an increase of approximately 59% over 2010, and we invested approximately $390 million in oil and NGL-related capital projects. These investments have yielded higher cash flows and margins that more than offset the decline in production volumes and realized prices from our natural gas production assets. We expect our oil and NGL production to continue to grow as a percentage of our total production as we pursue higher rate-of-return projects in economically attractive oil and NGL-rich areas.

As of December 31, 2011, our proved reserves were approximately 883 Bcfe, of which 49% were proved developed reserves. Our operations currently include primarily unconventional developmental drilling opportunities and exploratory prospects. We believe our emerging presence in the Eagle Ford Shale provides us opportunities for continued oil and NGL-focused investments over the next several years.

Our proved reserves and primary development plays are located in Texas, Appalachia, the Mid-Continent and Mississippi, which comprised 53%, 17%, 11% and 19% of our total proved reserves as of December 31, 2011. In 2011, our production totaled 46.6 Bcfe, compared to 47.2 Bcfe in 2010. Texas, Appalachia, the Mid-Continent and Mississippi comprised 38%, 20%, 28% and 14% of total production volumes during 2011. In the three years ended December 31, 2011, we drilled 156 gross (105.0 net) wells, of which 92% were productive wells. For a more detailed discussion of our reserves and production, see Item 2, ''Properties.''

In 2011, our capital expenditures were $446.7 million, of which $307.8 million, or 69%, was related to development drilling, $64.1 million, or 14%, was related to exploratory drilling and $50.0 million, or 11%, was related to leasehold acquisitions. The remaining $24.8 million, or 6%, was related to pipelines, gathering and facilities.

As of December 31, 2011, we owned approximately 1.1 million net acres of leasehold and royalty interests, approximately 29% of which were undeveloped. Many of our proved undeveloped locations and additional potential drilling locations are direct offsets or extensions from existing production. We believe we have several years of drilling opportunities on our existing undeveloped acreage based on our historical drilling rate.

Business Strategy

We intend to pursue the following business strategies:

- *Continue our "Gas-to-Oil" transition.* We anticipate oil and NGL production will provide approximately 42% of our total 2012 production, which is an increase of approximately 26% to 42% over our total 2011 oil and NGL production. Our planned 2012 capital projects are focused on oil and NGL exploration and development.
- *Grow our cash flows and margins.* We expect our operating cash flows and margins will continue to grow as we increase our oil and NGL production through investment in higher rate-of-return development oil projects.
- *Expand oil and NGL reserves and drilling inventory*. We anticipate spending up to approximately $325 million on oil and gas capital expenditures in 2012. We plan to allocate up to $245 million, or approximately 75% of this amount, to development drilling and related projects, primarily on our Eagle Ford Shale acreage in Gonzales County, Texas. We anticipate allocating the remaining $80 million, or approximately 25%, of our oil and gas capital expenditures to exploratory drilling projects in the Eagle Ford Shale and Mid-Continent region including our recently announced agreement to jointly explore approximately 13,000 gross acres of the Eagle Ford Shale in Lavaca County, Texas.
- *Improve our liquidity and financial position.* We expect to continue to use our operating cash flows and borrowings under our Revolver to fund our capital requirements in 2012. We expect to supplement these sources of liquidity with proceeds from the sale of non-core assets or by accessing the capital markets. Our Revolver provides for a maximum leverage of up to 4.5 times EBITDAX (as defined in the Revolver) through June 2013 and 4.0 times EBITDAX thereafter through its maturity in August 2016. We have no material debt maturities until 2016.
- *Pursue selective divestitures of non-core assets to increase margins, operational focus and liquidity.* Certain of our natural gas assets no longer represent core activities. We may dispose of certain of these assets and reinvest the proceeds into our oil and NGL-focused projects.
- *Retain long-term optionality of our core natural gas assets*. We maintain substantial natural gas properties, particularly in the Haynesville Shale and Cotton Valley Sands in East Texas and in the Selma Chalk in Mississippi, which are largely held by production. We plan to retain these assets, which provide us with the option to increase development in these regions when natural gas prices improve.
- *Manage risk exposure through an active hedging program*. We actively manage our exposure to commodity price fluctuations by hedging the commodity price risk for our expected production. The level of our hedging activity and duration of the instruments employed depend upon our cash flow at risk, available hedge prices and our operating strategy. For 2012, we have hedged approximately 47% of our estimated oil production at average floor/swap and ceiling prices of $97.08 and $99.61 per barrel. In addition, we have hedged approximately 32% of our estimated natural gas production at a weighted-average floor/swap price of $5.43 per MMBtu and ceiling price of $6.05 per MMBtu.

Contracts

Transportation

We have entered into contracts that provide firm transportation capacity rights for specified volumes per day on various pipeline systems for terms ranging from one to 15 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

Marketing

We generally sell our natural gas, oil and NGL products using short-term floating price physical and spot market contracts. For the year ended December 31, 2011, approximately 58% of our consolidated product revenue was attributable to five of our customers: Connect Energy Services, LLC, a subsidiary of PVR; Enogex, LLC; Chesapeake Operating, Inc.; Plains Marketing LP; and Shell Trading (US) Company.

Commodity Derivative Contracts

We generally utilize collar, swap and swaption derivative contracts, among others, to hedge against the variability in cash flows associated with anticipated sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

The counterparty to a collar or swap contract is required to make a payment to us if the settlement price for any settlement period is below the floor or swap price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling or swap price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. A swaption contract gives our counterparties the option to enter into a fixed price swap with us at a future date. If the forward commodity price for the term of the swaption is higher than or equal to the swaption strike price on the exercise date, the counterparty will exercise its option to enter into a fixed price swap at the swaption strike price for the term of the swaption, at which point the contract functions as a fixed price swap. If the forward commodity price for the term of the swaption is lower than the swaption strike price on the exercise date, the option expires and no fixed price swap is in effect.

We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of the end of the reporting period. The discounted cash flows utilize discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position and our own credit risk if the derivative is in a liability position.

Competition

The oil and natural gas industry is very competitive, and we compete with a substantial number of other companies that are large, well-established and have greater financial and operational resources than we do, which may adversely affect our ability to compete or grow our business. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations, electricity generation and the marketing of refined products. Competition is particularly intense in the acquisition of prospective oil and natural gas properties. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. We compete with other oil and natural gas companies to secure drilling rigs and other equipment necessary for the drilling and completion of wells and in recruiting and retaining of qualified personnel. Such equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. We also compete with substantially larger oil and gas companies in the marketing and sale of oil and natural gas, and the oil and natural gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers.

Government Regulation and Environmental Matters

Our operations are subject to stringent and extensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. Compliance with these laws and regulations increases our cost of doing business. Also, environmental laws and regulations have been subject to frequent changes over the years and the imposition of more stringent requirements, including any significant limitation on hydraulic fracturing, could have a material adverse effect on our financial condition and results of operations.

The following is a summary of the significant environmental laws to which our business operations are subject.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, is also known as the ''Superfund'' law. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on parties that are considered to have contributed to the release of a ''hazardous substance'' into the environment. Such ''responsible parties'' may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease properties that have been used for the exploration and production of oil and natural gas for a number of years. Many of these properties have been operated by third parties whose treatment or release of hydrocarbons or other wastes was not under our control. These properties, and any wastes that may have been released on them, may be subject to CERCLA, and we could potentially be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

RCRA. The Resource Conservation and Recovery Act, or the RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and clean up of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of RCRA. While there is currently an exclusion from RCRA for drilling fluids, produced waters and most of the other wastes associated with the exploration and production of oil or natural gas, it is possible that some of these wastes could be classified as hazardous waste in the future, and therefore be subject to RCRA.

Oil Pollution Act. The Oil Pollution Act of 1990, as amended, or the OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term ''waters of the United States'' has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. OPA subjects owners of facilities to strict, joint and several liability for all containment and clean up costs, and certain other damages arising from a spill.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, governs the discharge of certain pollutants into waters of the United States. The discharge of pollutants into regulated waters without a permit issued by the EPA or the state is prohibited. The Clean Water Act also requires the preparation and implementation of Spill Prevention, Control and Countermeasure Plans in connection with on-site storage of significant quantities of oil. Notably, in Pennsylvania, wastewater from the hydraulic fracturing process can no longer be sent to publicly owned treatment works directly. New wastewater discharges must be treated at a centralized waste treatment facility and comply with certain Total Dissolved Solids standards prior to being discharged to publicly owned treatment works. This restriction of disposal options for hydraulic fracturing waste may result in increased costs. The EPA is currently developing analogous pretreatment standards on the federal level.

Safe Drinking Water Act. The Safe Drinking Water Act, or the SDWA, and the Underground Injection Control Program promulgated under the SDWA, establish the requirements for salt water disposal well activities and prohibit the migration of fluid containing contaminants into underground sources of drinking water. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells in which we act as operator. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional plays like the Eagle Ford Shale, Granite Wash, Haynesville Shale and the Marcellus Shale formations. The U.S. Congress is currently considering the Fracturing Responsibility and Awareness of Chemicals Act to subject hydraulic fracturing operations to federal regulation and to require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing. Such costs and burdens could delay the development of unconventional gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Additionally, the EPA has commenced a comprehensive research study to investigate the potential adverse environmental impacts of hydraulic fracturing, including on water quality and public health, and a committee of the U.S. House of Representatives is also conducting an investigation into hydraulic fracturing practices. The initial EPA study results are expected to be available in late 2012.

Further, in light of the explosion and fire on the drilling rig Deepwater Horizon in the Gulf of Mexico, as well as recent incidents involving the release of natural gas and fluids as a result of drilling activities in the Marcellus Shale, there have been a variety of regulatory initiatives at both the federal and state levels to restrict oil and gas drilling operations in certain locations. For example, Pennsylvania has instituted a moratorium on leasing forest land for gas drilling. Additionally, the New York State Department of Environmental Conservation, or NYDEC, has ceased issuing drilling permits for horizontal drilling under the General Environmental Impact Statement, pending completion of the Supplemental General Environmental Impact Statement, or SGEIS, that takes into account the impacts of high volume hydraulic fracturing. However, the NYDEC has stated that it will consider individual, site-specific environmental reviews for any entity that wishes to proceed with a permit application as long as that review is of similar scope and depth as the SGEIS. We use hydraulic fracturing extensively and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and natural gas that we can economically recover.

Certain states in which we operate have adopted regulations requiring the disclosure of chemicals used in the hydraulic fracturing process. For instance, Texas, Pennsylvania and West Virginia have implemented chemical disclosure requirements for hydraulic fracturing operations. We currently disclose all hydraulic fracturing additives we use on www.FracFocus.org, a website created by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission. In addition to chemical disclosure rules, some states have implemented permitting, well construction or water withdrawal regulations that may increase the costs of hydraulic fracturing operations.

Clean Air Act. Our operations are subject to the Clean Air Act, or the CAA, and comparable state and local requirements. In 1990, the U.S. Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed, and continue to develop, regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Further, stricter requirements could negatively impact our production and operations. For example, the Texas Commission on Environmental Quality and the Railroad Commission of Texas have been evaluating possible additional regulation of air emissions in response to concerns about allegedly high concentrations of benzene in the air near drilling sites and natural gas processing facilities. These initiatives could lead to more stringent air permitting, increased regulation and possible enforcement actions at the local, state and federal levels.

Additionally, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs. The EPA published these proposed regulations to comply with a consent decree which required publication of proposed standards on or before July 28, 2011, and promulgation of final standards on or before April 3, 2012. The new rules would regulate emissions from several types of emission sources that have never before been subject to federal standards, and also include NSPS standards for completion of hydraulically fractured gas wells. The standards would apply to newly drilled and fractured wells, as well as existing wells that are refractured. The proposed NESHAPS regulations would apply to certain major sources of hazardous air pollutants not currently subject to Maximum Achievable Control Technology, or MACT, standards. We are currently researching the effect these proposed rules could have on our business, but generally expect them to add to the cost and expense of our operations.

There have been recent claims asserted that individual wells and other facilities should be "aggregated" together and their collective emissions considered in determining whether major source permitting requirements apply under the CAA. Were we required to aggregate individual wells and other facilities, it could bring us within the ambit of the Title V permitting program, as well as consideration as a major source for MACT applicability.

Increased regulation of and attention given by environmental interest groups, as well as state and federal regulatory authorities, to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. These developments could also lead to litigation challenging proposed or operating wells. The adoption of federal, state or local laws or the implementation of regulations regarding hydraulic fracturing that are more stringent could cause a decrease in the completion of new oil and gas wells, as well as increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

Greenhouse Gas Emissions. Both in the United States and worldwide, there is increasing attention being paid to the issue of climate change and the contributing effect of greenhouse gas, or GHG, emissions. On June 28, 2010, the EPA issued the "Final Mandatory Reporting of Greenhouse Gases" Rule, or the Reporting Rule, requiring all stationary sources that emit more than 25,000 tons of greenhouse gases per year to collect and report to the EPA data regarding such emissions. The Reporting Rule establishes a new comprehensive scheme, beginning in 2011, requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions occurring in the prior calendar year on a facility-by-facility basis. On November 9, 2010, the EPA issued final rules applying these regulations to the oil and gas source category, including oil and natural gas production, natural gas processing, transmission, distribution and storage facilities (Subpart W). This action does not require control of GHGs. However, the EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits.

In addition, in 2009, the EPA issued a final rule known as the EPA's Endangerment Finding, finding that current and projected concentrations of six key GHGs in the atmosphere threaten public health and the environment, as well as the welfare of current and future generations. Legal challenges to these findings have been asserted, and the U.S. Congress is considering legislation to delay or repeal the EPA's actions, but we cannot predict the outcome of this litigation or these efforts. The EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. These rules are currently subject to judicial challenge, but the D.C. Circuit has refused to stay their implementation while the challenges are pending.

As of July 1, 2011, the EPA requires facilities that must already obtain New Source Review permits for other pollutants to include GHGs in their permits for new construction projects that emit at least 100,000 tons per year of GHGs and existing facilities that increase their emissions by at least 75,000 tons per year. In December 2010, the EPA issued its plan to update pollution standards for fossil fuel power plants and petroleum refineries. The EPA had stated that it intended to propose standards for power plants in July 2011 and for refineries in December 2011 and issue final standards in May 2012 and November 2012, respectively. As of early December 2011, the EPA reportedly has prepared a proposal to regulate GHG emissions from only new plants, not existing ones, but that proposal is pending review at the Office of Management and Budget, and is not yet public. The EPA's failure to propose rules by the required date will delay final action, as well.

Also, many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities.

The U.S. Congress has considered a number of legislative proposals to restrict GHG emissions. It presently appears unlikely that comprehensive climate legislation will be passed by either house of the U.S. Congress in the near future, although energy legislation and other initiatives continue to be proposed that may be relevant to GHG emissions issues. In addition, various states, either individually or as part of regional initiatives, have begun taking actions to control and/or reduce GHG emissions. While it is not possible at this time to predict how regulation that may be enacted to address GHG emissions would impact our business, the modification of existing laws or regulations, or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations, and the provision of such information to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations.

Endangered Species Act. The Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species.

Employees and Labor Relations

We and our subsidiaries had a total of 153 employees as of December 31, 2011. We consider our current employee relations to be favorable. We and our employees are not subject to any collective bargaining agreements.

Available Information

Our internet address is *http://www.pennvirginia.com*. We make available free of charge on or through our website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Audit Committee Charter, Compensation and Benefits Committee Charter and Nominating and Governance Committee Charter, and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

All references in this Annual Report on Form 10-K to the ''NYSE'' refer to the New York Stock Exchange, and all references to the ''SEC'' refer to the Securities and Exchange Commission.

Item 1A *Risk Factors*

Our business and operations are subject to a number of risks and uncertainties as described below. However, the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, financial condition or results of operations. If any of the following risks actually occur, our business, financial condition or results of operations could suffer.

Natural gas and crude oil prices are volatile, and a substantial or extended decline in prices would hurt our profitability and financial condition.

Our revenues, operating results, cash flows, profitability, future rate of growth and the carrying value of our oil and gas properties depend heavily on prevailing market prices for natural gas, crude oil and NGLs. Historically, gas and oil prices have been volatile, and they are likely to continue to be volatile. Wide fluctuations in natural gas, crude oil and NGL prices may result from relatively minor changes in the supply of and demand for gas and oil, market demand and other factors that are beyond our control, including:

- domestic and foreign supplies of oil, natural gas and NGLs;
- political and economic conditions in oil or gas producing regions;
- overall domestic and foreign economic conditions;
- prices and availability of and demand for, alternative fuels;
- the availability of transportation facilities;
- weather conditions; and
- domestic and foreign governmental regulation.

Some of our projections and estimates are based on assumptions as to the future prices of gas and oil. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future will likely differ from our estimates. Any substantial or extended decline in the actual prices of natural gas or crude oil would have a material adverse effect on our business, financial position and results of operations (including reduced cash flows, borrowing capacity and possible asset impairment), the quantities of gas and oil reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operations. We have historically succeeded in substantially replacing reserves primarily through exploration and development and, to a lesser extent, acquisitions. We have conducted such activities on our existing oil and gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from such activities at acceptable costs. Currently depressed gas prices may further limit the types of reserves that can be developed at acceptable costs. Lower prices also decrease our cash flows and may cause us to reduce capital expenditures. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves if cash flows from operations are reduced and external sources of capital are limited. In addition, exploration and development activities involve numerous risks that may result in dry holes, the failure to produce oil and gas in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating acquisition opportunities. However, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources substantially greater than those available to us. In the event we are successful in completing an acquisition, we cannot ensure that such acquisition will consist of properties that contain economically recoverable reserves or that such acquisition will be profitably integrated into our operations.

We may not be able to fund our planned capital expenditures.

We make, and will continue to make, substantial capital expenditures to find, acquire, develop and produce oil and natural gas reserves. In 2012, we anticipate making capital expenditures, excluding acquisitions, of up to approximately $325 million.

If oil prices decrease, gas prices fail to recover or we encounter operating difficulties that result in our cash flow from operations being less than expected, we may have to reduce the capital we can spend unless we have borrowing capacity under our Revolver, or we can raise additional funds through asset sales or a debt or equity financing.

Future cash flows and the availability of financing will also be subject to a number of variables, such as our success in locating and producing new reserves, the level of production from existing wells and prices of oil and natural gas.

If our revenues were to decrease due to lower oil and gas prices, decreased production or other reasons, and if we could not obtain capital through the Revolver, or otherwise on acceptable terms, our ability to execute our development plans, replace our reserves or maintain production levels could be greatly limited.

The borrowing base under our Revolver may be reduced in the future if commodity prices decline.

The borrowing base under our Revolver is $380 million as of December 31, 2011. Our borrowing base is re-determined twice a year and is scheduled to be redetermined during April 2012. Due primarily to depressed natural gas prices and a decrease in our proved developed reserves, we anticipate that the borrowing base may be materially reduced. As a result, we may be unable to obtain adequate funding under our Revolver. If funding is not available when or in the amounts needed, or is available only on unfavorable terms, it might adversely affect our development plan as currently anticipated and our ability to make new acquisitions, each of which could have a material adverse effect on our production, financial condition and results of operations.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive natural gas or oil reserves will be found. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- shortages in experienced labor;
- failure to or delays in securing necessary regulatory approvals and permits, including delays due to potential hydraulic fracturing regulations;
- title problems;
- fires, explosions, blow-outs and surface cratering; and
- adverse weather conditions.

The prevailing prices of oil and gas also affect the cost of and the demand for drilling rigs, production equipment and related services. The availability of drilling rigs and equipment can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that natural gas or oil is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. In addition, limitations on the use of hydraulic fracturing could have an adverse affect on our ability to develop and produce oil and gas from new wells, which would reduce our rate of return on these wells and our cash flows. Drilling activities can result in dry wells or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, nor can we be sure that our overall drilling success rate or our drilling success rate within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our business, financial condition and results of operations. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.

We are exposed to the credit risk of our customers and joint interest partners, and nonpayment or nonperformance by these parties would reduce our cash flows.

We are subject to risk from loss resulting from our customers' and joint interest partners' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of revenues. In 2011, 58% of our total consolidated product revenues resulted from five of our customers. Any nonpayment or nonperformance by our customers would reduce our cash flows.

Our business involves many operating risks, including hydraulic fracturing, that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for and the production and transportation of oil and natural gas, including well stimulation and completion activities such as hydraulic fracturing. These operating risks include:

- fires, explosions, blowouts, cratering and casing collapses;
- formations with abnormal pressures;
- pipeline ruptures or spills;
- uncontrollable flows of oil, natural gas or well fluids;
- migration of fracturing fluids into surrounding groundwater;
- spills or releases of fracturing fluids including from trucks sometimes used to deliver these materials;
- spills or releases of brine or other produced water that may go off-site;
- subsurface conditions that prevent us from (i) stimulating the planned number of stages, (ii) accessing the entirety of the wellbore with our tools during completion or (iii) removing all fracturing materials from the wellbore to allow production to begin;
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases;
- personal injuries and death; and
- natural disasters.

Any of these risks could result in substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. In addition, under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

If we experience any of these problems with well stimulation and completion activities, such as hydraulic fracturing, our ability to explore for and produce natural gas or oil may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of:

- the need to shutdown, abandon and relocate drilling operations;
- the need to sample, test and monitor drinking water in particular areas and to provide filtration or other drinking water supplies to users of water supplies that may have been impacted or threatened by potential contamination from fracturing fluids;
- the need to modify drill sites to ensure there are no spills or releases off-site and to investigate and/or remediate any spills or releases that might have occurred; and
- suspension of our operations.

In accordance with industry practice, we maintain insurance at a level that balances the cost of insurance with our assessment of the risk and our ability to achieve a reasonable rate of return on our investments. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our business, financial condition and results of operations.

Our business depends on transportation facilities owned by others.

We deliver substantially all of our oil and natural gas production through pipelines that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines as well as gathering systems and processing facilities. The unavailability or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and market our oil and natural gas.

Estimates of oil and natural gas reserves are not precise.

This Annual Report on Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and, therefore, changes often occur as these variables evolve and commodity prices fluctuate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the estimated quantities and present value of our reserves.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

At December 31, 2011, approximately 51% of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

You should not assume that the present value of estimated future net cash flows (standardized measure) referred to herein is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided herein. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for us.

We may record impairment losses on our oil and gas properties.

Quantities of proved reserves are estimated based on economic conditions in existence in the period of assessment. Lower oil and gas prices may have the impact of shortening the economic lives on certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves occur, it will have the effect of increasing the rates of depreciation, depletion and amortization, or DD&A, on the affected properties, which would decrease earnings or result in losses through higher DD&A expense. The revisions may also be sufficient enough to cause impairment losses on certain properties that would result in a further non-cash charge to reported earnings.

GAAP requires that the carrying value of oil and gas properties be reviewed on a periodic basis for possible impairment. An impairment charge is recognized when the carrying value of oil and gas properties is greater than the undiscounted future net cash flows attributable to the property. In addition to revisions to reserves and the impact of lower commodity prices, impairments may occur due to increases in estimated operating and development costs. During the past several years, we have been required to impair certain of our oil and gas properties and related assets. If natural gas, crude oil and NGL prices decline or we drill uneconomic wells, it is reasonably possible that we will have to record a significant impairment in the future. While an impairment charge reflects our ability to recover the carrying value of our investments, it does not impact our cash flows from operating activities.

We have limited control over the activities on properties we do not operate.

In 2011, other companies operated approximately 23% of our net production. Our success in properties operated by others will depend upon a number of factors outside of our control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

Certain working interest owners in our properties have the right to control the timing of drilling activities on our properties under certain circumstances.

Under certain circumstances, certain of the other working interest owners in our properties have the right to limit the amount of drilling activities that can take place on our properties at any given time. If these working interest owners chose to exercise this right, we could be required to scale back anticipated drilling activities on the affected properties. In such an event, production from the affected properties would be deferred, thereby decreasing production from the properties in the short-term.

Our producing property acquisitions carry significant risks.

Acquisition of producing oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. In the event we do complete an acquisition, its success will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future oil and gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results, and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and gas are subject to extensive federal, state and local laws and regulations, including complex environmental laws. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals or a failure to comply with existing legal requirements may harm our business, results of operations or financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations, we may be charged with remedial costs and land owners may file claims for alternative water supplies, property damage or bodily injury. Laws and regulations protecting the environment have become more stringent in recent years, and may, in some circumstances, result in liability for environmental damage regardless of negligence or fault. In addition, pollution and similar environmental risks generally are not fully insurable. These liabilities and costs could have a material adverse effect on our business, financial condition or results of operations. See Item 1, ''Business — Government Regulation and Environmental Matters.''

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The practice of hydraulic fracturing has come under increased scrutiny by the environmental community. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into prospective rock formations to stimulate oil and natural gas production. We use this completion technique on substantially all of our wells. The EPA has commenced a study of the potential environmental impact of hydraulic fracturing, with initial results of the study anticipated to be available by late 2012. The EPA also announced that one of its enforcement initiatives for 2011 to 2013 is to focus on environmental compliance by the energy extraction sector. Also, the Secretary of Energy Advisory Board has established a Natural Gas Subcommittee to make recommendations on improving safety and environmental performance of hydraulic fracturing. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations.

Individually or collectively, such new legislation or regulation could result in increased compliance and operating costs, delays or additional operating restrictions. If the use of hydraulic fracturing is limited or prohibited, it could delay or effectively prevent the extraction of oil and gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition and results of operations.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The U.S. Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act, was signed into law on July 21, 2010 and requires the Commodities Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the new legislation. In December 2011, the CFTC extended temporary exemptive relief from certain swap regulation provisions of the legislation until July 16, 2012. In its rulemaking under the Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will make these regulations effective. The Act may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

Derivative transactions may limit our potential gains and involve other risks.

In order to manage our exposure to price risks in the sale of our oil and natural gas, we periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of two years or less. While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains if oil or natural gas prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how oil or natural gas prices fluctuate in the future.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

In addition, derivative instruments involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of proposed legislation.

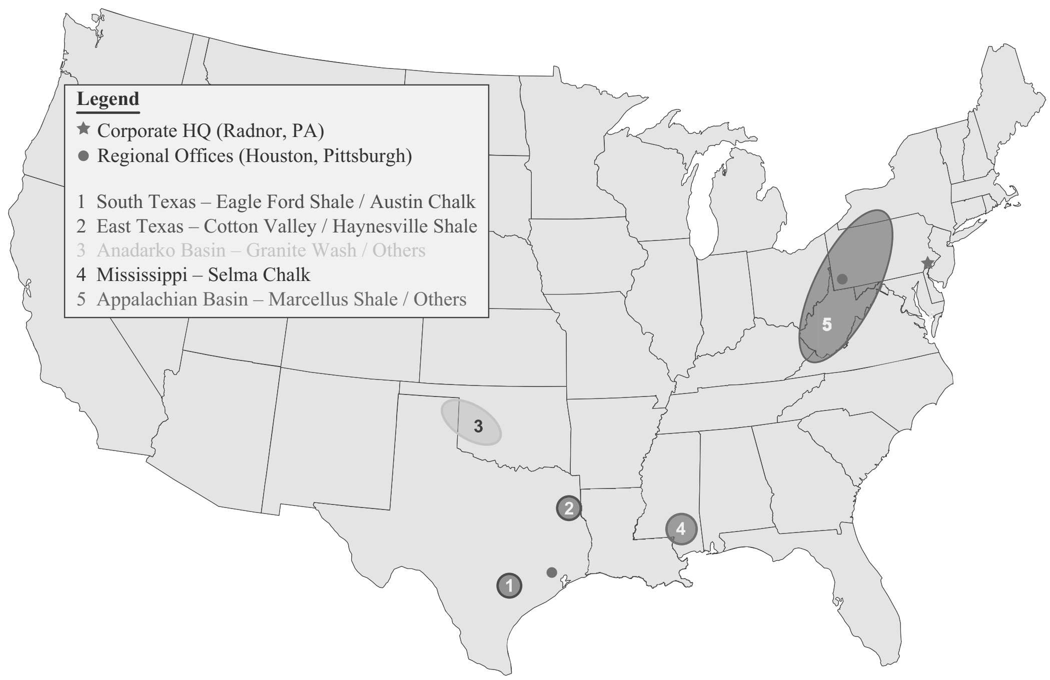
Legislation has been proposed in the U.S. Congress that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, the repeal of the percentage depletion allowance for oil and natural gas properties, the elimination of current deductions for intangible drilling and development costs, the elimination of the deduction for certain domestic production activities and an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could have a material adverse effect on us.

Item 1B *Unresolved Staff Comments*

We have received no written SEC staff comments regarding our periodic or current reports under the Exchange Act which were issued 180 days or more preceding the end of our 2011 fiscal year that remain unresolved.

Item 2 ***Properties***

The following map shows the general locations of our oil and gas production investments and our regional office locations as of December 31, 2011:



Facilities

We are headquartered in Radnor, Pennsylvania, with regional offices in Pittsburgh, Pennsylvania and Houston, Texas. We also have district operations facilities at various locations in Texas, Oklahoma, Mississippi, Pennsylvania and West Virginia. All of our office facilities are leased with the exception of our district operations facilities in Scottsville, Texas and Ravencliff, West Virginia. We believe that our facilities are adequate for our current needs.

Title to Oil and Gas Properties

Prior to completing an acquisition of producing oil and gas assets, we review title opinions on all material leases. However, as is customary in the oil and gas industry, we make only a cursory review of title to farmout acreage and to acquire undeveloped oil and gas leases. Prior to the commencement of drilling operations, a thorough title examination is conducted. To the extent the title examination reflects defects, we cure such title defects. If we are unable to cure any title defect of a nature such that it would not be prudent to commence drilling operations on a property, we could suffer a loss of our investment in the property. Our oil and gas properties are subject to customary royalty interests, liens for debt obligations, current taxes and other burdens that we believe do not materially interfere with the use or materially affect the value of such properties. We believe that we have satisfactory title to all of our properties and the associated oil and natural gas in accordance with standards generally accepted in the oil and natural gas industries.

Preparation of Reserves Estimates

Our policies and practices regarding the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. Our Manager of Engineering is primarily responsible for overseeing the preparation of the reserve estimate by our independent third party engineers, Wright & Company, Inc. Our Manager of Engineering has over 26 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the state of Texas as a Professional Engineer. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

The technical person primarily responsible for review of our reserve estimates at Wright & Company, Inc., meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Wright & Company, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petro physicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. For additional information about the risks inherent in our estimates of proved reserves, see Item 1A, ''Risk Factors.''

Summary of Oil and Gas Reserves

Proved Reserves

The following tables present certain information regarding our proved reserves as of December 31, 2011, 2010 and 2009. The proved reserve estimates presented below were prepared by Wright & Company, Inc., independent petroleum engineers. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see the Supplemental Information on Oil and Gas Producing Activities (Unaudited) in the Notes to the Consolidated Financial Statements and the report of Wright & Company, Inc., which is included as an Exhibit to this Annual Report on Form 10-K. We did not file any reports during the year ended December 31, 2011 with any federal authority or agency with respect to our estimate of oil and gas reserves.

	Natural Gas	Oil and Condensate	Natural Gas Equivalents	Standardized Measure	Price Measurement Used(1)	
	(Bcf)	(MMBbl)	(Bcfe)	$ in millions	$/MMBtu	$/Bbl
2011						
Developed	331	16.5	429	$602		
Undeveloped	339	19.1	454	52		
	670	35.6	883	$654	$3.95	$92.22
2010						
Developed	413	14.8	502	$574		
Undeveloped	332	18.0	440	67		
	745	32.8	942	$641	$4.38	$79.43
2009						
Developed	388	8.4	439	$425		
Undeveloped	389	18.0	496	100		
	777	26.4	935	$525	$3.87	$61.18

(1) Natural gas and oil prices were based on average (beginning of month basis) sales prices per Mcf and Bbl with the representative price of natural gas adjusted for basis premium and energy content to arrive at the appropriate net price.

All of our reserves are located in the continental United Sates. The following table sets forth by region the estimated quantities of proved reserves and the percentages thereof that are represented by proved developed reserves as of December 31, 2011:

Region	Proved Reserves	% of Total Proved Reserves	% Proved Developed
	(Bcfe)		
Texas	468	53%	36%
Appalachia	146	17%	74%
Mid-Continent	99	11%	71%
Mississippi	170	19%	47%
	883	100%	

Significant Reserves

Our Carthage field in the Cotton Valley and Haynesville Shale plays in East Texas represents approximately 29% of our total proved reserves as of December 31, 2011. This is the only field that comprises 15% or more of our total proved reserves as of that date. The following table sets forth certain information with respect to our Carthage field for the periods presented:

	Year Ended December 31,		
	2011	2010	2009
Production:			
Natural gas (MMcf)	8,417	9,725	9,081
Crude oil and NGLs (MBbl)	546	496	517
Average prices:			
Natural gas ($ per Mcfe)	$ 3.69	$ 4.13	$ 3.71
Crude oil and NGLs ($ per Bbl)	$58.36	$47.28	$34.84
Production cost (aggregate $ per Mcfe)	$ 1.36	$ 1.03	$ 1.27

Proved Undeveloped Reserves

The proved undeveloped reserves included in our reserve estimates relate to wells that are forecasted to be drilled within the next five years. The following table sets forth the changes in our proved undeveloped reserves during the year ended December 31, 2011:

	Natural Gas	Oil and Condensate	Natural Gas Equivalents
	(Bcf)	(MMBbl)	(Bcfe)
Proved undeveloped reserves at beginning of year	332	18.0	440
Revisions of previous estimates	(22)	(2.6)	(38)
Extensions, discoveries and other additions	46	4.8	76
Sale of reserves in place	(9)	—	(9)
Conversion to proved developed reserves	(8)	(1.1)	(15)
Proved undeveloped reserves at end of year	339	19.1	454

As of December 31, 2011, our proved undeveloped reserves increased to 454 Bcfe from 440 Bcfe as of December 31, 2010. We experienced performance-related revisions of approximately 38 Bcfe, including downward revisions of 20 Bcfe due primarily to interference with offsetting and adjacent wells in the Granite Wash and minor performance-related revisions in other areas, as well as 18 Bcfe due to a combination of factors that included non-participation, lease expirations, the effect of lower natural gas prices and locations that are not expected to be developed during a five-year period. During 2011, we had proved undeveloped reserve additions of 76 Bcfe, including approximately 45 Bcfe of natural gas primarily in the Marcellus Shale in Pennsylvania and Selma Chalk in Mississippi and approximately 31 Bcfe of natural gas, crude oil and NGLs in the Eagle Ford Shale in Texas. We had a decrease of 9 Bcfe due to the sale of substantially all of our properties, including proved undeveloped locations, in the Arkoma Basin. Finally, we converted approximately 15 Bcfe, primarily in the Granite Wash, to proved developed reserves.

During 2011, we incurred capital expenditures of approximately $40 million in connection with the conversion of proved undeveloped reserves to proved developed reserves.

Oil and Gas Production Volumes, Prices and Costs

Oil and Gas Production by Region

The following tables set forth by region the average daily production and total production for the periods presented:

	Average Daily Production for the Year Ended December 31,			Total Production for the Year Ended December 31,		
Region	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
		(MMcfe)			(MMcfe)	
Texas	48.9	37.1	35.9	17,854	13,526	13,116
Appalachia	24.8	28.5	31.4	9,063	10,397	11,465
Mid-Continent[1]	35.8	42.0	35.1	13,082	15,340	12,826
Mississippi	18.0	20.9	21.5	6,554	7,643	7,822
Gulf Coast[2]	—	0.8	15.8	—	295	5,771
	127.5	129.3	139.7	46,553	47,201	51,000

(1) We sold a substantial portion of our Arkoma Basin properties in August 2011, which represented estimated annual production of approximately 4 Bcfe.

(2) We completed the sale of our Gulf Coast properties in January 2010.

Production Prices and Costs

The following table sets forth the average sales prices per unit of volume and our production costs, not including ad valorem and severance taxes, per unit of production for the periods presented:

	Year Ended December 31,		
	2011	**2010**	**2009**
Average prices:			
Natural gas ($ per Mcf)	$ 4.10	$ 4.40	$ 3.91
Crude oil ($ per Bbl)	$93.19	$75.56	$57.68
NGLs ($ per Bbl)	$47.83	$39.69	$29.86
Production cost (aggregate $ per Mcfe)	$ 1.12	$ 1.06	$ 1.09

Drilling Activities

Wells Drilled

The following table sets forth the gross and net exploratory and development wells that we drilled during the years ended December 31, 2011, 2010 and 2009 as well as wells that were in progress at the end of each year. The number of wells drilled refers to the number of wells completed at any time during the year, regardless of when drilling was initiated.

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	45	32.1	59	40.0	25	16.9
Non-productive	—	—	—	—	1	1.0
Under evaluation	2	1.3	—	—	4	1.8
Total development	47	33.4	59	40.0	30	19.7
Exploratory						
Productive	5	3.8	5	2.7	2	1.0
Non-productive	4	2.7	3	1.2	—	—
Under evaluation	—	—	1	0.5	—	—
Total exploratory	9	6.5	9	4.4	2	1.0
Total	56	39.9	68	44.4	32	20.7
Wells in progress at end of year	7	5.8	6	3.5	2	1.5

The following table sets forth the regions in which we drilled our wells for the periods presented:

	2011		2010		2009	
Region	Gross	Net	Gross	Net	Gross	Net
Texas	32	26.7	12	11.1	10	9.5
Appalachia	5	4.3	1	0.8	2	2.0
Mid-Continent	19	8.9	41	18.7	17	6.2
Mississippi	—	—	14	13.8	3	3.0
Total	56	39.9	68	44.4	32	20.7

Present Activities

As of December 31, 2011, we had seven gross (5.8 net) wells in progress, all of which were located in the Eagle Ford Shale play in South Texas. As of February 21, 2011, six of these wells were successfully completed and placed on production and the remaining well is waiting on completion. Our two (1.3) net wells under evaluation are located in the Marcellus Shale in Pennsylvania.

Delivery Commitments

We generally sell our natural gas, oil and NGL products using short-term floating price physical and spot market contracts. Although it is not our general practice, from time to time we enter into certain transactions in which we provide production commitments extending beyond one month. As of December 31, 2011, we did not have any material commitments to provide a fixed and determinable quantity of our natural gas, crude oil or NGL production beyond the current month.

Productive Wells

The following table sets forth the number of productive wells in which we had a working interest as of December 31, 2011:

Region	Primarily Natural Gas		Primarily Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Texas	359	255.6	29	24.3	388	279.9
Appalachia	671	566.0	—	—	671	566.0
Mid-Continent	94	40.7	10	6.8	104	47.5
Mississippi	569	549.2	—	—	569	549.2
	1,693	1,411.5	39	31.1	1,732	1,442.6

Of the total wells presented in the table above, we are the operator of 1,503 gross (1,465 gas and 38 oil) and 1,358.7 net (1,328.1 gas and 30.6 oil) wells. In addition to the above working interest wells, we own royalty interests in 2,884 gross wells.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2011 (in thousands):

Developed		Undeveloped		Total	
Gross	Net	Gross	Net	Gross	Net
875	813	465	274	1,340	1,087

Our acreage is located in Texas, Appalachia, the Mid-Continent and Mississippi regions of the United States. The primary terms of our leases generally range from three to five years and we do not have any concessions. As of December 31, 2011, our net undeveloped acreage is scheduled to expire as shown in the table below, unless the primary lease terms are extended, held by production or otherwise changed:

	2012	2013	2014	Thereafter
Percent of gross undeveloped acreage	16%	38%	9%	37%
Percent of net undeveloped acreage	13%	18%	10%	59%

We do not believe that the scheduled expiration of our undeveloped acreage will substantially affect our ability or plans to conduct our exploration and development activities. The amount of acreage expiring in 2013 includes a large non-operated lease position in Appalachia in which we hold a 25% interest; we have no remaining capitalized costs related to this lease.

Item 3 *Legal Proceedings*

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject. See Item 1, ‘‘Business — Government Regulation and Environmental Matters,’’ for a more detailed discussion of our material environmental obligations.

Item 4 *Reserved*

Part II

Item 5 ***Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities***

Market Information

Our common stock is traded on the NYSE under the symbol "PVA." The high and low sales prices (composite transactions) and dividends declared related to each fiscal quarter in 2011 and 2010 were as follows:

Quarter Ended	Sales Price High	Sales Price Low	Cash Dividends Declared
December 31, 2011	$ 6.97	$ 4.21	$0.05625
September 30, 2011	$14.12	$ 5.47	$0.05625
June 30, 2011	$17.20	$12.88	$0.05625
March 31, 2011	$18.31	$14.40	$0.05625
December 31, 2010	$18.80	$13.99	$0.05625
September 30, 2010	$20.50	$13.38	$0.05625
June 30, 2010	$29.25	$19.63	$0.05625
March 31, 2010	$27.80	$21.64	$0.05625

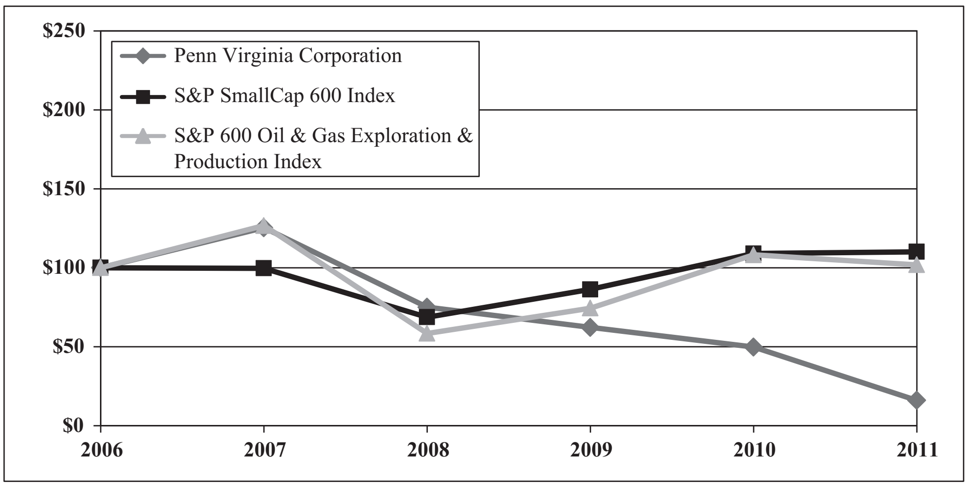
Equity Holders

As of February 10, 2012, there were 453 record holders and approximately 6,330 beneficial owners (held in street name) of our common stock.

Performance Graph

The following graph compares our five-year cumulative total shareholder return (assuming reinvestment of dividends) with the cumulative total return of the Standard & Poor's 600 Oil & Gas Exploration & Production Index and the Standard & Poor's Small Cap 600 Index. As of December 31, 2011, there were nine companies in the Standard & Poor's 600 Oil & Gas Exploration & Production Index: Approach Resources Inc., Contango Oil & Gas Company, GeoResources Inc., Gulfport Energy Corporation, Penn Virginia Corporation, Petroleum Development Corporation, Petroquest Energy Inc., Stone Energy Corporation and Swift Energy Company. The graph assumes $100 is invested on January 1, 2007 in us and each index at December 31, 2006 closing prices.

COMPARISON OF CUMULATIVE FIVE-YEAR TOTAL RETURN



	December 31,				
	2007	2008	2009	2010	2011
Penn Virginia Corporation	$125.30	$74.98	$62.25	$ 49.79	$ 16.05
S&P Small Cap 600 Index	$ 99.70	$68.72	$86.29	$109.00	$110.10
S&P 600 Oil & Gas Exploration & Production Index	$126.64	$58.42	$74.42	$108.20	$101.88

Item 6 ***Selected Financial Data***

The following selected historical financial information was derived from our Consolidated Financial Statements as of and for the years ended December 31, 2011, 2010, 2009, 2008 and 2007. The selected financial data should be read in conjunction with our Consolidated Financial Statements and the accompanying Notes and Supplemental Data in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplemental Data."

	2011	2010	2009	2008	2007
	(in thousands, except per share amounts)				
Statements of Income Data[1]:					
Revenues	$ 306,005	$ 254,438	$ 235,206	$ 469,490	$ 303,505
Depreciation, depletion and amortization	$ 162,534	$ 134,700	$ 154,351	$ 135,687	$ 88,237
Operating income (loss)[2]	$ (155,419)	$ (98,808)	$ (205,346)	$ 142,034	$ 77,155
Income (loss) from continuing operations	$ (132,915)	$ (65,327)	$ (130,856)	$ 93,619	$ 35,196
Net income (loss)[3]	$ (132,915)	$ 19,667	$ (77,368)	$ 181,520	$ 80,810
Income (loss) attributable to Penn Virginia Corporation	$ (132,915)	$ (8,423)	$ (114,643)	$ 121,084	$ 50,491
Common Stock Data[1]:					
Earnings (loss) per common share, basic					
Continuing operations	$ (2.90)	$ (1.44)	$ (2.99)	$ 2.23	$ 0.92
Discontinued operations	$ —	$ 0.12	$ 0.37	$ 0.66	$ 0.40
Gain on sale of discontinued operations	$ —	$ 1.13	$ —	$ —	$ —
Net income (loss)	$ (2.90)	$ (0.19)	$ (2.62)	$ 2.89	$ 1.32
Earnings (loss) per common share, diluted					
Continuing operations	$ (2.90)	$ (1.44)	$ (2.99)	$ 2.22	$ 0.91
Discontinued operations	$ —	$ 0.12	$ 0.37	$ 0.65	$ 0.40
Gain on sale of discontinued operations	$ —	$ 1.13	$ —	$ —	$ —
Net income (loss)	$ (2.90)	$ (0.19)	$ (2.62)	$ 2.87	$ 1.31
Weighted-average shares outstanding:					
Basic	45,784	45,553	43,811	41,760	38,061
Diluted	45,784	45,553	43,811	42,031	38,358
Actual shares outstanding at year-end	45,714	45,557	45,272	41,786	41,331
Dividends declared per share	$ 0.225	$ 0.225	$ 0.225	$ 0.225	$ 0.225
Market value at year-end	$ 5.29	$ 16.82	$ 21.29	$ 25.66	$ 42.89
Number of shareholders	6,787	6,708	3,486	8,761	8,196
Balance Sheet and Other Financial Data[1]:					
Property and equipment, net	$1,777,575	$1,705,584	$1,479,452	$1,646,215	$1,198,506
Total assets	$1,943,053	$1,944,600	$2,888,507	$2,996,565	$2,253,461
Total debt	$ 697,307	$ 506,536	$ 498,427	$ 539,438	$ 315,655
Shareholders' equity	$ 846,309	$ 980,276	$1,237,999	$1,222,442	$ 911,700
Cash provided by operating activities	$ 144,741	$ 79,839	$ 117,733	$ 246,587	$ 186,550
Cash paid for capital expenditures	$ 445,623	$ 405,994	$ 205,676	$ 547,058	$ 488,470
Other Statistical Data:					
Total production (MMcfe)	46,553	47,201	51,000	46,881	40,569
Proved reserves (Bcfe)	883	942	935	916	680

(1) PVG's results of operations, financial position and cash flows have been reported as discontinued operations for all periods presented. Accordingly, all items presented above not classified as discontinued operations exclude amounts attributable to PVG unless indicated otherwise.

(2) Operating income (loss) for 2011, 2010, 2009, 2008 and 2007 included impairment charges of $104.7 million, $46.0 million, $106.4 million, $20.0 million and $2.6 million related to our oil and gas properties and other assets.

(3) Net income (loss) for 2010 includes a gain of $51.5 million, net of tax, on the sale of discontinued operations representing the final disposition of our interests in PVG.

Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion and analysis of the financial condition and results of operations of Penn Virginia Corporation and its subsidiaries ("Penn Virginia," "we," "us" or "our") should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, "Financial Statements and Supplemental Data." All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated.

Overview of Business

We are an independent oil and gas company engaged in the exploration, development and production of natural gas and oil in various domestic onshore regions. We have a geographically diverse asset base with areas of operations in Texas, Appalachia, the Mid-Continent and Mississippi regions of the United States. As of December 31, 2011, we had proved natural gas and oil reserves of approximately 883 Bcfe. Our operations include primarily the drilling of unconventional development wells and exploring for new exploitable resources.

We are currently primarily focused on the Eagle Ford Shale in South Texas. During 2011, we brought on line approximately 30 gross wells in this play. In 2011, we also pursued selected drilling opportunities in the horizontal Granite Wash play in our Mid-Continent region through participation in wells drilled by our joint venture partner.

The following table sets forth certain summary operating and financial statistics for the periods presented:

	Year Ended December 31,		
	2011	2010	2009
Total production (MMcfe)	46,553	47,201	51,000
Daily production (MMcfe per day)	127.5	129.3	139.7
Product revenues, as reported	$ 300,046	$251,336	$ 228,659
Product revenues, as adjusted for derivatives	$ 323,608	$284,816	$ 288,565
Operating loss	$(155,419)	$ (98,808)	$(205,346)
Interest expense	$ 56,216	$ 53,679	$ 44,231
Cash provided by operating activities	$ 144,741	$ 79,839	$ 117,733
Cash paid for capital expenditures	$ 445,623	$405,994	$ 205,676
Cash and cash equivalents at end of period	$ 7,512	$120,911	$ 79,017
Debt outstanding, net of discounts, at end of period	$ 697,307	$506,536	$ 498,427
Credit available under revolving credit facility at end of period(1)	$ 199,600	$299,268	$ 299,268
Net development wells drilled	33.4	40.0	19.7
Net exploratory wells drilled	6.5	4.4	1.0

(1) As reduced by outstanding borrowings and letters of credit.

Key Developments

During 2011, the following general business developments and corporate actions had an impact on our results of operations and financial position: (i) drilling results in the Eagle Ford Shale, Granite Wash and Marcellus Shale plays, (ii) acquiring properties in the Eagle Ford Shale play, (iii) selling our Arkoma Basin assets and related restructuring activities, (iv) entering into a new five-year revolving credit facility, or the Revolver, and (v) offering and selling $300 million of our 7.25% Senior Notes due 2019, or 2019 Senior Notes, together with the tender offer to repurchase our 4.50% Convertible Senior Subordinated Notes due 2012, or the Convertible Notes.

Drilling Results and Future Development Plans

During 2011, we drilled a total of 39.9 net wells, including 26.7 net wells in the Eagle Ford Shale, 8.9 net wells in the Mid-Continent region, primarily in the Granite Wash, and 4.3 net wells in the Marcellus Shale.

We currently have three rigs drilling in the Eagle Ford Shale. We have drilled a total of 39 wells since we began operations in this play during the second half of 2010. Of the total wells drilled, 35 (29.2 net) wells are producing, one is waiting on completion and three are in progress as of February 22, 2012. The producing wells have had an average peak gross production rate of approximately 1,000 BOEPD per well. Eagle Ford Shale production was approximately 9,800 (6,280 net) BOEPD at the end of January 2012, with oil comprising approximately 89 percent, NGLs comprising approximately six percent and natural gas comprising approximately five percent. We expect to continue drilling in this play for the remainder of 2012 and beyond. We have allocated approximately 85% of our capital expenditures during 2012 for activities in the Eagle Ford Shale.

In the Mid-Continent region, we successfully drilled and completed 6.2 net development wells in the Granite Wash during 2011. We plan to continue our Granite Wash development program, primarily as a non-operator. Our exploratory program in the Mid-Continent region, excluding the Granite Wash, resulted in four dry holes (2.7 net) at an aggregate cost of $18.9 million during 2011.

In 2011, we drilled five gross (4.3 net) and completed three horizontal test wells in the Marcellus Shale located in the central portion of our approximately 35,000 net acreage position in Potter and Tioga counties, Pennsylvania. The completed wells are connected to a pipeline and have been producing since October 2011 at an average rate of 2.5 MMcf per day. Completion of the remaining two wells and all other significant exploration and development activities have been deferred due primarily to the recent decline in natural gas prices. We will monitor long-term production of the existing wells and natural gas prices to determine the potential resumption of a development program in this area.

Eagle Ford Property Acquisitions

During 2011, we acquired approximately 7,300 net Eagle Ford Shale acres in Gonzales County, Texas for approximately $27 million, or approximately $3,700 per acre. The acreage acquired in these transactions is in close proximity to our initial 2010 Eagle Ford Shale acquisition, which was approximately 6,800 net acres for $31.1 million. We are the operator of the combined Gonzales County acreage with an average working interest of approximately 81%.

In December 2011, we entered into an agreement with a major oil and gas company to jointly explore approximately 13,000 gross acres of the Eagle Ford Shale in Lavaca County, Texas. The agreement establishes an area of mutual interest near our existing acreage in Gonzales County. Depending on the future participation of other companies, our minimum working interest will be approximately 50%. Under the terms of the agreement, we must drill six wells by September 1, 2012 to earn our entire interest in the acreage. We will carry our counterparty on its working interest in the first three wells.

Disposition of Arkoma Basin Properties and Related Restructuring Action

In August 2011, we sold a substantial portion of our Arkoma Basin assets for approximately $30 million, excluding transaction costs and subject to customary purchase and sale adjustments. Upon the final settlement, we recognized an insignificant loss in connection with the transaction, following an impairment of approximately $71 million in the second quarter of 2011. The sale, which was effective July 1, 2011, included primarily natural gas and coal bed methane properties comprising approximately 73,000 net acres in Oklahoma and Texas with proved reserves of approximately 37.1 Bcfe as well as related inventory and equipment. For 2011, these properties represented production of approximately 2 Bcfe.

During 2011, we completed an organizational restructuring due primarily to our decision to exit the Arkoma Basin and to consolidate certain operations functions to our Houston, Texas location. This restructuring and consolidation resulted in the termination of approximately 40 employees, most of whom were based out of our Tulsa, Oklahoma office, as well as certain corporate positions in connection with a reallocation of administrative responsibilities. We recorded a charge of $2.3 million, including termination benefits, employee and office relocation costs, and a lease charge in connection with this action.

Completion of a New Credit Facility

In August 2011, we entered into the Revolver which provides for a $300 million revolving commitment, including a $20 million sublimit for the issuance of letters of credit. At December 31, 2011, the Revolver had a borrowing base of $380 million which takes into account the Arkoma Basin sale discussed above, and an accordion feature that allows us to increase the commitment up to the lower of the borrowing base or $600 million upon receiving additional commitments from one or more lenders. The permitted leverage ratio (net debt divided by EBITDAX, as defined in the Revolver) is 4.5 through periods ending on or before June 30, 2013, after which it will be 4.0.

The Revolver is guaranteed by Penn Virginia and all of our material subsidiaries, or the Guarantor Subsidiaries. The obligations under the Revolver are secured by a first priority lien on substantially all of our proved oil and gas reserves and a pledge of our equity interests in the Guarantor Subsidiaries. The Revolver will mature in August 2016.

In January 2012, we amended the Revolver to enhance our ability to hedge production. Previously, our hedging was limited to the lesser of certain fixed percentages of our reasonably anticipated production from proved developed reserves and total proved reserves. The amendment expands the potential volume subject to hedging to certain percentages of reasonably anticipated production from proved undeveloped reserves as well as proved developed reserves. The permitted percentages vary depending on the future period to which the hedging transaction relates.

Senior Note Offering and Tender Offer to Repurchase Convertible Notes

In April 2011, we completed the offering of the 2019 Senior Notes. Total proceeds received from the offering were $293.5 million, net of underwriting and debt issuance costs. We used $237.1 million of the proceeds to repurchase approximately 98% of the Convertible Notes plus accrued interest, and we have a total of $4.9 million (principal amount) of Convertible Notes currently outstanding. We used the remainder of the proceeds to provide working capital for general corporate purposes, including capital expenditures.

Results of Operations

Year Ended December 31, 2011 Compared to the Year Ended December 31, 2010

The following table sets forth a summary of certain operating and financial performance for the periods presented:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
Total Production:				
Natural gas (MMcf)	33,410	38,919	(5,509)	(14)%
Crude oil (MBbl)	1,283	709	574	81%
NGL (MBbl)	907	672	235	35%
Total production (MMcfe)	46,553	47,201	(648)	(1)%
Realized prices, before derivatives:				
Natural gas ($/Mcf)	$ 4.10	$ 4.40	$ (0.30)	(7)%
Crude oil ($/Bbl)	93.19	75.56	17.63	23%
NGL ($/Bbl)	47.83	39.69	8.14	21%
Total ($/Mcfe)	$ 6.45	$ 5.32	$ 1.13	21%
Revenues				
Natural gas	$ 137,070	$ 171,141	$ (34,071)	(20)%
Crude oil	119,582	53,532	66,050	123%
NGL	43,394	26,663	16,731	63%
Total product revenues	300,046	251,336	48,710	19%
Gain on sales of property and equipment	3,570	648	2,922	451%
Other income	2,389	2,454	(65)	(3)%
Total revenues	306,005	254,438	51,567	20%
Operating Expenses				
Lease operating	36,988	35,757	(1,231)	(3)%
Gathering, processing and transportation	15,157	14,180	(977)	(7)%
Production and ad valorem taxes	13,690	13,917	227	2%
General and administrative	48,328	58,383	10,055	17%
Exploration	78,943	49,641	(29,302)	(59)%
Depreciation, depletion and amortization	162,534	134,700	(27,834)	(21)%
Impairments	104,688	45,959	(58,729)	(128)%
Other	1,096	709	(387)	(55)%
Total operating expenses	461,424	353,246	(108,178)	(31)%
Operating loss	(155,419)	(98,808)	(56,611)	(57)%
Other income (expense)				
Interest expense	(56,216)	(53,679)	(2,537)	(5)%
Loss on extinguishment of debt	(25,421)	—	(25,421)	NM
Derivatives	15,651	41,906	(26,255)	(63)%
Other	335	2,403	(2,068)	(86)%
Loss from continuing operations before income taxes	(221,070)	(108,178)	(112,892)	(104)%
Income tax benefit	88,155	42,851	45,304	106%
Loss from continuing operations	(132,915)	(65,327)	(67,588)	(103)%
Income from discontinued operations, net of tax	—	33,448	(33,448)	NM
Gain on sale of discontinued operations	—	51,546	(51,546)	NM
Net income (loss)	(132,915)	19,667	(152,582)	NM
Less net income attributable to noncontrolling interests	—	(28,090)	28,090	NM
Loss attributable to Penn Virginia Corporation	$(132,915)	$ (8,423)	$(124,492)	NM

NM — Not meaningful

Production

The following tables set forth a summary of our total and daily production volumes by product and geographical region for the periods presented:

Natural Gas

	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	% Change
	(MMcfe)			(MMcfe per day)			
Texas	9,670	10,510	(840)	26.5	28.8	(2.3)	(8)%
Appalachia	9,055	10,358	(1,303)	24.8	28.4	(3.6)	(13)%
Mid-Continent	8,244	10,338	(2,094)	22.6	28.3	(5.7)	(20)%
Mississippi	6,441	7,505	(1,064)	17.6	20.6	(3.0)	(14)%
Gulf Coast (Divested)	—	208	(208)	—	0.6	(0.6)	(100)%
Total production	33,410	38,919	(5,509)	91.5	106.7	(15.2)	(14)%

Crude Oil

	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	% Change
	(MBbl)			(MBbl per day)			
Texas	868.7	113.5	755.2	2.38	0.31	2.07	665%
Appalachia	0.5	5.1	(4.6)	0.00	0.01	(0.01)	(90)%
Mid-Continent	395.1	559.3	(164.2)	1.08	1.53	(0.45)	(29)%
Mississippi	18.9	22.9	(4.0)	0.05	0.06	(0.01)	(17)%
Gulf Coast (Divested)	—	7.7	(7.7)	—	0.02	(0.02)	(100)%
Total production	1,283.2	708.5	574.7	3.51	1.93	1.58	81%

NGLs

	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	% Change
	(MBbl)			(MBbl per day)			
Texas	495.2	389.1	106.1	1.36	1.07	0.29	27%
Appalachia	0.9	1.4	(0.5)	0.00	0.00	(0.00)	(36)%
Mid-Continent	411.1	274.4	136.7	1.13	0.75	0.38	50%
Gulf Coast (Divested)	—	6.9	(6.9)	—	0.02	(0.02)	(100)%
Total production	907.2	671.8	235.4	2.49	1.84	0.65	35%

Combined Total

	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	% Change
	(MMcfe)			(MMcfe per day)			
Texas	17,854	13,526	4,328	48.9	37.1	11.8	32%
Appalachia	9,063	10,397	(1,334)	24.8	28.5	(3.7)	(13)%
Mid-Continent	13,082	15,340	(2,258)	35.8	42.0	(6.2)	(15)%
Mississippi	6,554	7,643	(1,089)	18.0	20.9	(2.9)	(14)%
Gulf Coast (Divested)	—	295	(295)	—	0.8	(0.8)	(100)%
Total production	46,553	47,201	(648)	127.5	129.3	(1.8)	(1)%

The decline in total production during 2011 was due primarily to the lack of any significant natural gas drilling since mid-2010 and the subsequent natural production declines as well as the effect of the sale of our Arkoma Basin properties. The effect of the sale of the Arkoma Basin properties was approximately 2 Bcfe. The natural gas production decline was substantially offset by an increase in oil and NGL production attributable to our drilling activity in the Eagle Ford Shale. Approximately 28% of total production on an equivalent basis in 2011 was attributable to oil and NGLs, an increase over the previous year of approximately 59%. The shift in production mix reflects our focus on emerging oil and liquids-rich plays in the Eagle Ford Shale in Texas and the Mid-Continent region. During 2011, our Eagle Ford Shale production represented approximately 11% of our total production. We had no production from this play in 2010.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product and geographical region for the periods presented:

Natural Gas

	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2011	2010	(Unfavorable)	2011	2010	(Unfavorable)
				($ per Mcfe)		
Texas	$ 38,072	$ 43,247	$ (5,175)	$3.94	$4.11	$(0.17)
Appalachia	36,636	45,581	(8,945)	4.05	4.40	(0.35)
Mid-Continent	35,315	47,694	(12,379)	4.28	4.61	(0.33)
Mississippi	27,047	33,351	(6,304)	4.20	4.44	(0.24)
Gulf Coast (Divested)	—	1,268	(1,268)	—	6.10	(6.10)
Total revenues	$137,070	$171,141	$(34,071)	$4.10	$4.40	$(0.30)

Crude Oil

	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2011	2010	(Unfavorable)	2011	2010	(Unfavorable)
				($ per Bbl)		
Texas	$ 81,473	$ 8,844	$72,629	$ 93.79	$77.92	$ 15.87
Appalachia	40	164	(124)	80.00	32.16	47.84
Mid-Continent	36,145	42,176	(6,031)	91.48	75.41	16.07
Mississippi	1,924	1,750	174	101.80	76.42	25.38
Gulf Coast (Divested)	—	598	(598)	—	77.66	(77.66)
Total revenues	$119,582	$53,532	$66,050	$ 93.19	$75.56	$ 17.63

NGLs

	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2011	2010	(Unfavorable)	2011	2010	(Unfavorable)
				($ per Bbl)		
Texas	$24,753	$15,150	$ 9,603	$49.99	$38.94	$ 11.05
Appalachia	46	51	(5)	51.11	36.43	14.68
Mid-Continent	18,595	11,152	7,443	45.23	40.64	4.59
Gulf Coast (Divested)	—	310	(310)	—	44.93	(44.93)
Total revenues	$43,394	$26,663	$16,731	$47.83	$39.69	$ 8.14

Combined Total

	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2011	2010	(Unfavorable)	2011	2010	(Unfavorable)
				($ per Mcfe)		
Texas	$144,298	$ 67,241	$ 77,057	$8.08	$4.97	$ 3.11
Appalachia	36,722	45,796	(9,074)	4.05	4.40	(0.35)
Mid-Continent	90,055	101,022	(10,967)	6.88	6.59	0.29
Mississippi	28,971	35,101	(6,130)	4.42	4.59	(0.17)
Gulf Coast (Divested)	—	2,176	(2,176)	—	7.38	(7.38)
Total revenues	$300,046	$251,336	$ 48,710	$6.45	$5.32	$ 1.13

As illustrated below, oil and NGL production volume coupled with improved oil and NGL pricing were the significant factors for increasing revenues. The increase was partially offset by lower natural gas production volumes and prices. The following table provides an analysis of the change in our revenues for the year ended December 31, 2011 as compared to the year ended December 31, 2010:

	Revenue Variance Due to		
	Volume	Price	Total
Natural gas	$(24,223)	$ (9,848)	$(34,071)
Crude oil	43,420	22,630	66,050
NGL	9,343	7,388	16,731
	$ 28,540	$20,170	$ 48,710

Effects of Derivatives

Our natural gas and crude oil revenues may change significantly from period to period as a result of changes in commodity prices. As part of our risk management strategy, we use derivative financial instruments to hedge natural gas and crude oil prices. In 2011 and 2010, we received $23.6 million and $33.5 million in cash settlements of oil and gas derivatives.

The following table reconciles natural gas and crude oil revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Year Ended December 31,		Favorable	
	2011	2010	(Unfavorable)	% Change
Natural gas revenues as reported	$137,070	$171,141	$(34,071)	(20)%
Cash settlements on natural gas derivatives, net	22,158	33,914	(11,756)	(35)%
Natural gas revenues adjusted for derivatives	$159,228	$205,055	$(45,827)	(22)%
Natural gas prices per Mcf, as reported	$ 4.10	$ 4.40	$ (0.29)	(7)%
Cash settlements on natural gas derivatives per Mcf	0.66	0.87	(0.21)	(24)%
Natural gas prices per Mcf adjusted for derivatives	$ 4.77	$ 5.27	$ (0.50)	(10)%
Crude oil revenues as reported	$119,582	$ 53,532	$ 66,050	123%
Cash settlements on crude oil derivatives, net	1,404	(434)	1,838	424%
Crude oil revenues adjusted for derivatives	$120,986	$ 53,098	$ 67,888	128%
Crude oil prices per Bbl, as reported	$ 93.19	$ 75.56	$ 17.64	23%
Cash settlements on crude oil derivatives per Bbl	1.09	(0.61)	1.71	279%
Crude oil prices per Bbl adjusted for derivatives	$ 94.29	$ 74.94	$ 19.34	26%

Gain on Sales of Property and Equipment

In December 2011, we sold approximately 2,700 net undeveloped acres in Butler and Armstrong counties in Pennsylvania for proceeds of $8.1 million, net of transaction costs. We recognized a gain of $3.3 million in connection with this transaction. In addition, we recognized several individually insignificant gains on the sale of property, equipment, tubular inventory and well material during both 2011 and 2010.

Other Income

Other income, which includes ancillary gathering, transportation, compression and water disposal fees, decreased marginally during 2011 as compared to 2010.

Operating Expenses

The following table summarizes certain of our operating expenses per Mcfe for the periods presented:

	Year Ended December 31,		Favorable	
	2011	2010	(Unfavorable)	% Change
Lease operating	$0.79	$0.76	$(0.03)	(4)%
Gathering, processing and transportation	0.33	0.30	(0.03)	(8)%
Production and ad valorem taxes	0.29	0.29	0.00	0%
General and administrative excluding share-based compensation and restructuring charges	0.83	0.90	0.07	8%
General and administrative	1.04	1.24	0.20	16%
Depreciation, depletion and amortization	3.49	2.85	(0.64)	(22)%

Lease Operating

Lease operating expense increased during 2011 due to higher employee-related and environmental compliance costs as well as higher work-over costs, particularly in the East Texas region. In addition, certain other costs, including water disposal, chemical treatment and general repairs and maintenance were generally higher commensurate with higher oil and NGL volume during 2011. These cost increases were partially offset by lower compression costs attributable to lower natural gas production in 2011 and our ongoing efforts to rationalize certain compression assets in our more mature producing regions in Appalachia and Mississippi.

Gathering, Processing and Transportation

Gathering, processing and transportation charges increased during 2011 due primarily to both higher processing costs and related volumes associated with NGL production. Due to lower overall natural gas volumes, particularly in the Appalachian region, we were unable to recover the cost of all of our unused firm transportation capacity.

Production and Ad Valorem Taxes

Production and ad valorem taxes decreased on an absolute basis due to marginally lower production in 2011 as well as a decrease in the severance tax rate imposed by the State of Oklahoma on certain wells during the second half of 2011. We also recorded a property tax recovery from prior periods of $1.2 million in 2011 attributable to wells located in West Virginia. In 2010, we recorded ad valorem tax settlements of $1.4 million with certain jurisdictions that were also attributable to prior periods. As a percentage of revenue, excluding the recovery and settlements, production and ad valorem taxes decreased to 5.0% in 2011 from 6.1% during 2010.

General and Administrative

The following table sets forth the components of general and administrative expenses for the periods presented:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
Recurring general and administrative expenses	$38,547	$42,372	$ 3,825	9%
Share-based compensation	7,430	7,811	381	5%
Restructuring expenses	2,351	8,200	5,849	71%
	$48,328	$58,383	$10,055	17%

Recurring general and administrative expenses decreased due to lower employee headcount and lower support costs from restructuring actions taken during 2011 and 2010. Share-based compensation charges decreased during 2011 due primarily to a smaller number of awards that vested upon grant due to retirement eligibility. Restructuring expenses during 2011 included termination benefits, office and employee relocation and lease costs attributable to the restructuring following the sale of our Arkoma Basin properties. Restructuring expenses during 2010 included termination benefits and office and employee relocation costs as well as a $3.5 million charge related to the assignment of the lease of our former Kingsport, Tennessee office.

Exploration

The following table sets forth the components of exploration expenses for the periods presented:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
Dry hole costs	$18,864	$11,282	$ (7,582)	(67)%
Geological and geophysical costs	11,202	10,168	(1,034)	(10)%
Unproved leasehold amortization	42,076	24,993	(17,083)	(68)%
Drilling rig charges	4,620	—	(4,620)	NM
Other, primarily delay rentals	2,181	3,198	1,017	32%
	$78,943	$49,641	$(29,302)	(59)%

The increase in dry hole costs was attributable primarily to four gross (2.7 net) unsuccessful wells in the Mid-Continent region during 2011 as compared to three gross (1.2 net) during 2010 in the same region. Geological and geophysical costs reflected a larger exploration program in 2011. The increase in amortization of unproved leaseholds was due primarily to significant acquisitions during 2010. In addition, we incurred rig-related charges during the 2011 period in connection with the current suspension of our drilling program in the Marcellus Shale.

Depreciation, Depletion and Amortization (DD&A)

The following tables set forth the components of DD&A and the nature of the variances for the periods presented:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
Depletion	$157,365	$127,836	$(29,529)	(23)%
Depreciation – Oil and gas operations	2,429	2,536	107	4%
Depreciation – Corporate	2,241	3,884	1,643	42%
Amortization	499	444	(55)	(12)%
	$162,534	$134,700	$(27,834)	(21)%

	DD&A Variance Due to Production	DD&A Variance Due to Rates	DD&A Variance Due to Total
Year ended December 31, 2011 compared to 2010	$1,849	$(29,683)	$(27,834)

The effect of lower overall production volume on DD&A was more than offset by higher depletion rates associated with oil and NGL production. Our average depletion rate increased to $3.38 per Mcfe for 2011 from $2.71 per Mcfe for 2010 due primarily to higher capitalized finding and development costs attributable to our oil wells in the Eagle Ford Shale.

Impairments

The following table summarizes the impairments recorded for the periods presented:

	Year Ended December 31,		Favorable	
	2011	2010	(Unfavorable)	% Change
Oil and gas properties	$104,688	$43,067	$(61,621)	NM
Other	—	2,892	2,892	NM
	$104,688	$45,959	$(58,729)	NM

During 2011, we recognized an impairment of our Arkoma Basin assets for $71.1 million, which was triggered by the expected disposition of these high-cost gas properties. As described in Note 3, we completed the sale of these properties in August 2011. Also during 2011, we recognized an impairment of our horizontal coal bed methane properties in the Appalachian region for $26.6 million and certain dry-gas properties in Mississippi for $7.0 million due primarily to market declines in gas prices. During 2010, we incurred impairment charges related to our Mid-Continent coal bed methane properties as a result of market declines in gas prices and to an area in the Anadarko Basin of the Mid-Continent region where we drilled an uneconomic well. In addition, we recorded impairment charges attributable to certain oil and gas inventory assets triggered primarily by declines in asset quality.

Other

During 2011, we recorded a reserve of $0.2 million for litigation attributable to properties that were previously sold. This matter was ultimately settled in January 2012 for the reserved amount. In addition, we wrote down certain gas imbalance assets that originated in prior years due to lower settlement rates. During 2010, we recorded a loss on the disposition of our Gulf Coast properties.

Interest Expense

The following table summarizes the components of our interest expense for the periods presented:

	Year Ended December 31,		Favorable	
	2011	2010	(Unfavorable)	% Change
Interest on borrowings and related fees	$51,384	$43,060	$(8,324)	(19)%
Accretion of original issue discount	3,427	8,109	4,682	58%
Amortization of debt issuance costs	3,380	3,875	495	13%
Capitalized interest	(1,983)	(1,384)	599	43%
Other, net	8	19	11	58%
	$56,216	$53,679	$(2,537)	(5)%

The issuance of the 2019 Senior Notes at 7.25% and borrowings under the Revolver, offset by the repurchase of approximately 98% of the outstanding Convertible Notes with an effective interest rate of 8.5%, resulted in an approximate $88 million higher weighted-average balance of debt outstanding during 2011 as compared to 2010. Accordingly, interest expense increased due to the higher average outstanding principal balance partially offset by lower effective interest rates attributable to the 2019 Senior Notes and Revolver. Capitalized interest was higher during 2011 due to higher carrying values on eligible capital projects.

Loss on Extinguishment of Debt

The repurchase in April 2011 of approximately 98% of the outstanding Convertible Notes resulted in a loss on extinguishment of debt of $24.2 million. The loss was comprised of non-cash charges for the excess of cash paid for the liability component over the carrying value, plus the write-off of a pro rata share of debt issuance costs and incremental transaction fees paid in cash. In addition, we recognized a charge of $1.2 million in August 2011 attributable to the Revolver and a change in the composition of the bank syndicate.

Derivatives

The following table summarizes the components of our derivatives income for the periods presented:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
Oil and gas derivative unrealized gain (loss)	$ (9,140)	$ 3,213	$(12,353)	NM
Oil and gas derivative realized gain	23,562	33,480	(9,918)	(30)%
Interest rate swap unrealized gain (loss)	(2,589)	5,875	(8,464)	(144)%
Interest rate swap realized gain (loss)	3,818	(662)	4,480	NM
	$15,651	$41,906	$(26,255)	(63)%

We received cash settlements of $27.4 million during 2011 and $32.8 million during 2010. The amount received during 2011 includes $2.9 million attributable to the termination of our interest rate swap.

Other

Other income decreased due primarily to lower interest income earned on average cash balances during 2011 and gains on the sale of non-operating investments recognized during 2010.

Income Taxes

The effective tax benefit rate for continuing operations during 2011 was 39.9% compared to 39.6% for 2010. Due to the operating losses incurred, we recognized an income tax benefit during both periods. In addition, the effective tax rate for 2011 includes a deferred tax asset valuation allowance due primarily to the inability to recognize a tax benefit for certain state net operating losses.

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

The following table sets forth a summary of certain operating and financial performance for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Total Production:				
Natural gas (MMcf)	38,919	43,338	(4,419)	(10)%
Crude oil (MBbl)	709	750	(41)	(6)%
NGL (MBbl)	672	527	145	28%
Total production (MMcfe)	47,201	51,000	(3,799)	(7)%
Realized prices, before derivatives:				
Natural gas ($/Mcf)	$ 4.40	$ 3.91	$ 0.49	13%
Crude oil ($/Bbl)	75.56	57.68	17.88	31%
NGL ($/Bbl)	39.69	29.86	9.83	33%
Total ($/Mcfe)	$ 5.32	$ 4.48	$ 0.84	19%
Revenues				
Natural gas	$ 171,141	$ 169,666	$ 1,475	1%
Crude oil	53,532	43,258	10,274	24%
NGL	26,663	15,735	10,928	69%
Total product revenues	251,336	228,659	22,677	10%
Gain on sale of property and equipment	648	2,372	(1,724)	(73)%
Other income	2,454	4,175	(1,721)	(41)%
Total revenues	254,438	235,206	19,232	8%
Operating Expenses				
Lease operating	35,757	44,392	8,635	19%
Gathering, processing and transportation	14,180	11,307	(2,873)	(25)%
Production and ad valorem taxes	13,917	15,044	1,127	7%
General and administrative	58,383	49,690	(8,693)	(17)%
Exploration	49,641	57,754	8,113	14%
Depreciation, depletion and amortization	134,700	154,351	19,651	13%
Impairments	45,959	106,415	60,456	57%
Other	709	1,599	890	56%
Total operating expenses	353,246	440,552	87,306	20%
Operating loss	(98,808)	(205,346)	106,538	52%
Other income (expense)				
Interest expense	(53,679)	(44,231)	(9,448)	(21)%
Derivatives	41,906	31,568	10,338	33%
Other	2,403	1,259	1,144	91%
Loss from continuing operations before income taxes	(108,178)	(216,750)	108,572	(50)%
Income tax benefit	42,851	85,894	(43,043)	(50)%
Loss from continuing operations	(65,327)	(130,856)	65,529	(50)%
Income from discontinued operations, net of tax	33,448	53,488	(20,040)	(37)%
Gain on sale of discontinued operations, net of tax	51,546	—	51,546	NM
Net income (loss)	19,667	(77,368)	97,035	125%
Less net income attributable to noncontrolling interests	(28,090)	(37,275)	9,185	25%
Net loss attributable to Penn Virginia Corporation	$ (8,423)	$(114,643)	$106,220	93%

Production

The following tables set forth a summary of our total and daily production volumes by product and geographical region for the periods presented:

Natural Gas

	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	% Change
	(MMcfe)			(MMcfe per day)			
Texas	10,510	9,966	544	28.8	27.3	1.5	5%
Appalachia	10,358	11,453	(1,095)	28.4	31.4	(3.0)	(10)%
Mid-Continent	10,338	9,602	736	28.3	26.3	2.0	8%
Mississippi	7,505	7,694	(189)	20.6	21.1	(0.5)	(2)%
Gulf Coast (Divested)	208	4,623	(4,415)	0.6	12.7	(12.1)	(96)%
Total production	38,919	43,338	(4,419)	106.7	118.8	(12.1)	(10)%

Crude Oil

	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	% Change
	(MBbl)			(MBbl per day)			
Texas	113.5	109.9	3.6	0.31	0.30	0.01	3%
Appalachia	5.1	1.8	3.3	0.01	0.00	0.01	183%
Mid-Continent	559.3	476.5	82.8	1.53	1.31	0.22	17%
Mississippi	22.9	21.3	1.6	0.06	0.06	0.00	7%
Gulf Coast (Divested)	7.7	140.9	(133.2)	0.02	0.39	(0.37)	(95)%
Total production	708.5	750.4	(41.9)	1.93	2.06	(0.13)	(6)%

NGLs

	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	% Change
	(MBbl)			(MBbl per day)			
Texas	389.1	415.3	(26.2)	1.07	1.14	(0.07)	(6)%
Appalachia	1.4	0.2	1.2	0.00	0.00	0.00	NM
Mid-Continent	274.4	60.8	213.6	0.75	0.17	0.58	351%
Gulf Coast (Divested)	6.9	50.4	(43.5)	0.02	0.14	(0.12)	(86)%
Total production	671.8	526.7	145.1	1.84	1.45	0.39	28%

Combined Total

	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	% Change
	(MMcfe)			(MMcfe per day)			
Texas	13,526	13,116	410	37.1	35.9	1.2	3%
Appalachia	10,397	11,465	(1,068)	28.5	31.4	(2.9)	(9)%
Mid-Continent	15,340	12,826	2,514	42.0	35.1	6.9	20%
Mississippi	7,643	7,822	(179)	20.9	21.5	(0.6)	(2)%
Gulf Coast (Divested)	295	5,771	(5,476)	0.8	15.8	(15.0)	(95)%
Total production	47,201	51,000	(3,799)	129.3	139.7	(10.4)	(7)%

The decline in production during 2010 was attributable to the disposition of our Gulf Coast properties in January 2010, the significant reduction in drilling activity in 2009 and natural declines in production rates. We also experienced equipment and service-related delays in new well completions during the first half of 2010 primarily in the Lower Bossier (Haynesville) Shale play in the Texas region. The overall decline in production volume was partially offset by production from new wells in the Granite Wash play in the Mid-Continent region that were brought online during 2010 despite interference attributable to offset wells during stimulation.

NGL production increased to 18% of the total production in 2010 compared to 15% in 2009. In addition, a processing agreement was signed for a major portion of our Granite Wash production which contributed to the increase in 2010 NGL production.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product and geographical region for the periods presented:

Natural Gas

	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2010	2009	(Unfavorable)	2010	2009	(Unfavorable)
				($ per Mcfe)		
Texas	$ 43,247	$ 36,696	$ 6,551	$ 4.11	$3.68	$0.43
Appalachia	45,581	46,773	(1,192)	4.40	4.08	0.32
Mid-Continent	47,694	34,115	13,579	4.61	3.55	1.06
Mississippi	33,351	31,509	1,842	4.44	4.10	0.34
Gulf Coast (Divested)	1,268	20,573	(19,305)	6.10	4.45	1.65
Total revenues	$171,141	$169,666	$ 1,475	$ 4.40	$3.91	$0.49

Crude Oil

	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2010	2009	(Unfavorable)	2010	2009	(Unfavorable)
				($ per Bbl)		
Texas	$ 8,844	$ 5,984	$ 2,860	$77.92	$54.45	$ 23.47
Appalachia	164	85	79	32.16	47.22	(15.06)
Mid-Continent	42,176	27,828	14,348	75.41	58.40	17.01
Mississippi	1,750	1,283	467	76.42	60.23	16.19
Gulf Coast (Divested)	598	8,078	(7,480)	77.66	57.33	20.33
Total revenues	$53,532	$43,258	$10,274	$75.56	$57.68	$ 17.88

NGLs

	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2010	2009	(Unfavorable)	2010	2009	(Unfavorable)
				($ per Bbl)		
Texas	$15,150	$12,479	$ 2,671	$38.94	$30.05	$ 8.89
Appalachia	51	5	46	36.43	25.00	11.43
Mid-Continent	11,152	1,777	9,375	40.64	29.23	11.41
Gulf Coast (Divested)	310	1,474	(1,164)	44.93	29.25	15.68
Total revenues	$26,663	$15,735	$10,928	$39.69	$29.86	$ 9.83

Combined Total

	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2010	2009	(Unfavorable)	2010	2009	(Unfavorable)
				($ per Mcfe)		
Texas	$ 67,241	$ 55,159	$ 12,082	$4.97	$4.21	$0.76
Appalachia	45,796	46,863	(1,067)	4.40	4.09	0.31
Mid-Continent	101,022	63,720	37,302	6.59	4.97	1.62
Mississippi	35,101	32,792	2,309	4.59	4.19	0.40
Gulf Coast (Divested)	2,176	30,125	(27,949)	7.38	5.22	2.16
Total revenues	$251,336	$228,659	$ 22,677	$5.32	$4.48	$0.84

As illustrated below, revenues were higher in 2010 compared to 2009 as the decline in production volume discussed above was more than offset by improved pricing for all three commodity product types. The following table provides an analysis of the change in our revenues for the year ended December 31, 2010 as compared to the year ended December 31, 2009:

	Revenue Variance Due to		
	Volume	Price	Total
Natural gas	$(17,301)	$18,776	$ 1,475
Crude oil	(2,393)	12,667	10,274
NGL	4,323	6,605	10,928
	$(15,371)	$38,048	$22,677

Effects of Derivatives

In 2010 and 2009, we received $33.5 million and $59.9 million in cash settlements of oil and gas derivatives.

The following table reconciles natural gas and crude oil revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Year Ended December 31,		Favorable	
	2010	2009	(Unfavorable)	% Change
Natural gas revenues as reported	$171,141	$169,666	$ 1,475	1%
Cash settlements on natural gas derivatives	33,914	55,545	(21,631)	(39)%
Natural gas revenues adjusted for derivatives	$205,055	$225,211	$(20,156)	(9)%
Natural gas prices per Mcf, as reported	$ 4.40	$ 3.91	$ 0.49	12%
Cash settlements on natural gas derivatives per Mcf	0.87	1.28	(0.41)	(32)%
Natural gas prices per Mcf adjusted for derivatives	$ 5.27	$ 5.19	$ 0.08	2%
Crude oil revenues as reported	$ 53,532	$ 43,258	$ 10,274	24%
Cash settlements on crude oil derivatives	(434)	4,361	(4,795)	(110)%
Crude oil revenues adjusted for derivatives	$ 53,098	$ 47,619	$ 5,479	12%
Crude oil prices per Bbl, as reported	$ 75.56	$ 57.68	$ 17.88	31%
Cash settlements on crude oil derivatives per Bbl	(0.61)	5.81	(6.43)	(111)%
Crude oil prices per Bbl adjusted for derivatives	$ 74.94	$ 63.49	$ 11.45	18%

Gain on Sales of Property and Equipment

In 2010, we recognized several individually insignificant gains on the sale of property, equipment, tubular inventory and well materials. In 2009, we recognized gains on the sale of certain properties and equipment in our Texas region.

Other Income

Other income decreased primarily as a result of lower gathering revenues during 2010 and the effect of a favorable audit settlement during 2009 partially offset by higher compression services revenues.

Operating Expenses

The following table summarizes certain of our operating expenses per Mcfe for the periods presented:

	Year Ended December 31,		Favorable	
	2010	2009	(Unfavorable)	% Change
Lease operating	$0.76	$0.87	$ 0.11	13%
Gathering, processing and transportation	0.30	0.22	(0.08)	(36)%
Production and ad valorem taxes	0.29	0.29	0.00	0%
General and administrative excluding share-based compensation and restructuring charges	0.90	0.78	(0.12)	(15)%
General and administrative	1.24	0.97	(0.27)	(27)%
Depreciation, depletion and amortization	2.85	3.03	0.18	6%

Lease Operating

The most significant decline in lease operating expenses resulted from decreases in charges that are generally correlated with production volume including water disposal, compressor and other equipment rentals, contract labor, chemical and treating and repairs and maintenance costs.

Gathering, Processing and Transportation

Gathering, processing and transportation charges increased during 2010 primarily as a result of a settlement with a gathering services provider attributable to disputed charges in several prior periods, as well as a change in the geographic distribution of production from the Gulf Coast to the Mid-Continent region where we typically experience higher processing costs associated with NGLs. These items were offset partially by the effects of lower volume in the current period.

Production and Ad Valorem Taxes

Production and ad valorem taxes decreased on an absolute basis by $1.1 million primarily reflecting ad valorem tax settlements of approximately $1.4 million with certain jurisdictions attributable to prior periods, while production taxes increased commensurately with higher revenues. As a percentage of revenue, production and ad valorem taxes, excluding the settlements, decreased to 6.1% in 2010 from 6.6% during 2009.

General and Administrative

The following table sets forth the components of general and administrative expenses for the periods presented:

	Year Ended December 31,		Favorable	
	2010	2009	(Unfavorable)	% Change
Recurring general and administrative expenses	$42,372	$40,034	$(2,338)	(6)%
Share-based compensation	7,811	9,127	1,316	14%
Restructuring expenses	8,200	529	(7,671)	NM
	$58,383	$49,690	$(8,693)	(17)%

Recurring general and administrative expenses increased in 2010 due primarily to higher consulting and professional fees attributable to our divestiture of Penn Virginia GP Holdings, L.P., or PVG. Share-based compensation charges decreased during 2010 due primarily to a smaller population of employees receiving awards. Restructuring expenses during both 2010 and 2009 include costs associated with the organization restructuring announced during November 2009. These costs include termination benefits, office and employee relocation costs as well as a $3.5 million charge related to the assignment of our lease of our former Kingsport, Tennessee office.

Exploration

The following table sets forth the components of exploration expenses for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Dry hole costs	$11,282	$ 1,397	$ (9,885)	NM
Geological and geophysical costs	10,168	912	(9,256)	NM
Unproved leasehold amortization	24,993	31,618	6,625	21%
Drilling rig charges	—	20,084	20,084	NM
Other, primarily delay rentals	3,198	3,743	545	15%
	$49,641	$57,754	$ 8,113	14%

The decrease in exploration expense is attributable primarily to rig standby charges incurred during 2009. These charges were a result of our 2009 drilling program reduction due to unfavorable economic conditions. In addition, the 2009 period reflects the initial impact of a change in accounting estimate to amortize collectively insignificant unproved properties over the average estimated life of the leases rather than amortizing some leases and assessing other leases individually. The decrease was offset partially by dry hole costs in the Mid-Continent region incurred during 2010 and higher geological and geophysical costs attributable to our larger 2010 exploration program.

Depreciation, Depletion and Amortization (DD&A)

The following tables set forth the components of DD&A and the nature of the variances for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Depletion	$127,836	$147,174	$19,338	13%
Depreciation – Oil and gas operations	2,536	2,756	220	8%
Depreciation – Corporate	3,884	3,922	38	1%
Amortization	444	499	55	11%
	$134,700	$154,351	$19,651	13%

	DD&A Variance Due to: Production	Rates	Total
Year ended December 31, 2010 compared to 2009	$11,499	$8,152	$19,651

Our average depletion rate decreased by $0.18 per Mcfe, or 6%, to $2.71 per Mcfe in 2010, from $2.89 per Mcfe in 2009. The reduction was a result of discoveries and the impact of impairments in 2010.

Impairments

The following table summarizes the impairments recorded for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Oil and gas properties	$43,067	$102,332	$59,265	58%
Other	2,892	4,083	1,191	29%
	$45,959	$106,415	$60,456	57%

During 2010, we incurred impairment charges related to our Mid-Continent coal bed methane properties as a result of market declines in gas prices and to an area in the Anadarko basin of the Mid-Continent region where we drilled an uneconomic well. In addition, we recorded impairment charges attributable to certain oil and gas inventory assets triggered primarily by declines in asset quality. We also incurred impairment charges on properties in North Dakota that were held for sale at the end of 2009. These properties were ultimately sold during 2010. During 2009, we incurred impairment charges in connection with the initial classification of the Gulf Coast properties as assets held for sale at their fair value less costs to sell, as well as impairments attributable to tubular inventory and other oil and gas properties.

Other

During 2010, we recorded a loss of $0.7 million on the disposition of our Gulf Coast properties. The loss reflects final purchase price adjustments associated with the period from the effective date in October 2009 to the closing date in January 2010. The 2009 period reflects a loss on the sales of tubular inventory and well materials.

Interest Expense

The following table summarizes the components of our total interest expense for the periods presented:

	Year Ended December 31,		Favorable	
	2010	2009	(Unfavorable)	% Change
Interest on borrowings and related fees	$43,060	$33,374	$(9,686)	(29)%
Accretion of original issue discount	8,109	7,523	(586)	(8)%
Amortization of debt issuance costs	3,875	2,679	(1,196)	(45)%
Interest rate swaps	—	3,969	3,969	NM
Capitalized interest	(1,384)	(2,318)	(934)	(40)%
Other, net	19	(996)	(1,015)	(102)%
	$53,679	$44,231	$(9,448)	(21)%

Interest expense increased due to higher interest rates on outstanding borrowings, primarily the 10.375% Senior Unsecured Notes, or 2016 Senior Notes, issued in June 2009. We realized higher amortization of the original issue discount and issuance costs on the 2016 Senior Notes and Convertible Notes, as well as higher amortization of issuance costs associated with the Revolver. In addition, 2009 included a reclassification of expense from accumulated other comprehensive income, or AOCI, attributable to the discontinuation of hedge accounting related to our interest rate swaps, as well as a reversal of interest cost attributable to the settlement of various state income tax positions.

Derivatives

The following table summarizes the components of our derivatives income for the periods presented:

	Year Ended December 31,		Favorable	
	2010	2009	(Unfavorable)	% Change
Oil and gas derivative unrealized gain (loss)	$ 3,213	$(26,690)	$ 29,903	112%
Oil and gas derivative realized gain	33,480	59,908	(26,428)	(44)%
Interest rate swap unrealized gain	5,875	111	5,764	NM
Interest rate swap realized loss	(662)	(1,761)	1,099	62%
	$41,906	$ 31,568	$ 10,338	33%

Cash received for settlements during 2010 was $32.8 million as compared to $58.1 million during 2009.

Other

Other income increased during 2010 due primarily to the gains on the sale of non-operating investments as well as higher interest income on the significantly larger cash balances held following of the disposition of our interests in PVG.

Income Taxes

The effective tax benefit rate for continuing operations was 39.6% for 2010 and 2009. Due to the operating losses incurred, we recognized an income tax benefit during both periods.

Discontinued Operations

The following table presents a summary of results of operations from discontinued operations for the periods presented:

	Year Ended December 31,		Favorable	
	2010	2009	(Unfavorable)	% Change
Revenues	$303,206	$579,931	$(276,725)	48%
Income from discontinued operations before taxes	$ 36,832	$ 64,130	$ (27,298)	43%
Income tax expense[(1)]	(3,384)	(10,642)	7,258	68%
Income from discontinued operations, net of taxes	$ 33,448	$ 53,488	$ (20,040)	37%

(1) Determined by applying the effective tax rate attributable to discontinued operations to the income from discontinued operations less noncontrolling interests that are fully attributable to PVG's operations.

The disclosures for 2010 provided in the table above reflect the results of operations of PVG through the date of disposition of our entire remaining interest in PVG on June 7, 2010.

Gain on Sale of Discontinued Operations

The following table summarizes the determination of the gain recognized upon the disposition of PVG:

Cash proceeds, net of offering costs (8,827,429 units × $15.76 per unit)	$ 139,120
Carrying value of noncontrolling interests in PVG at date of disposition	382,324
	521,444
Less: Carrying value of PVG's assets and liabilities at date of disposition	(434,782)
	86,662
Less: Income tax expense	(35,116)
Gain on sale of discontinued operations, net of tax	$ 51,546

Noncontrolling Interests

The decrease in net income attributable to noncontrolling interests during 2010 is directly attributable to the sale of our interests in PVG during June 2010. In September 2009, our ownership interest in PVG declined from 77.0% to 51.4% and in 2010 our ownership interest in PVG declined to zero.

Liquidity and Capital Resources

Sources of Liquidity

We are currently meeting our capital expenditures and working capital funding requirements with a combination of operating cash flows and borrowings from our Revolver. We have no material debt maturities until 2016. Our business strategy for 2012 requires capital expenditures in excess of our anticipated operating cash flows. Subject to the variability of commodity prices that impact our operating cash flows, anticipated timing of our capital projects and unanticipated expenditures such as acquisitions, we plan to fund our 2012 capital program with operating cash flows and borrowings from our Revolver. We expect to supplement these sources of liquidity with proceeds from the sale of non-core assets or, possibly, by accessing the capital markets. There can be no assurance that such actions would be successful, however, in which case we could reduce our 2012 planned capital expenditures.

In August 2011, we entered into the Revolver which matures in August 2016. The Revolver provides for a $300 million revolving commitment, including a $20 million sublimit for the issuance of letters of credit. The Revolver has a borrowing base of $380 million. There is an accordion feature that allows us to increase the commitment up to the lower of the borrowing base or $600 million upon receiving additional commitments from one or more lenders. The Revolver is available to us for general purposes including working capital, capital expenditures and acquisitions.

The borrowing base is redetermined semi-annually, and the next redetermination is scheduled to occur during April 2012. The primary assets supporting our borrowing base are our proved developed reserves, approximately 77% of which are natural gas. Due primarily to the significant decline in natural gas prices that has continued into the first quarter of 2012 and despite the increase in our oil reserves, we anticipate a potentially material reduction in our borrowing base from its current level of $380 million. As of the date of this filing, we are unable to determine a meaningful potential range of the reduction, due primarily to the fact that a number of determinative variables are not known at this time; however, we do not anticipate a material reduction to our current Revolver commitment of $300 million. Accordingly, our current business plans anticipate us borrowing amounts under the Revolver that are within the current commitment level of $300 million.

As of February 21, 2012, we had approximately $11 million of cash on hand and $182.6 million of unused borrowing capacity under our Revolver. The borrowing capacity is determined by reducing the revolving commitment of $300 million by outstanding borrowings of $116.0 million and outstanding letters of credit of $1.4 million.

The following table summarizes our borrowing activity under the Revolver during the periods presented:

	Borrowings Outstanding		
	Weighted-Average	**Maximum**	**Weighted-Average Rate**
Three months ended December 31, 2011	$61,696	$99,000	1.9448%
August 2, 2011 through December 31, 2011[(1)]	$44,974	$99,000	1.9118%

(1) There were no amounts outstanding under the previous credit facility from January 1, 2011 through its termination date of August 2, 2011.

Our revenues are subject to significant volatility as a result of changes in commodity prices. Accordingly, we actively manage the exposure of our operating cash flows to commodity price fluctuations by hedging the commodity price risk for a portion of our expected production through the use of derivatives, typically collar, swap and swaption contracts. The level of our hedging activity and duration of the instruments employed depend upon our cash flow at risk, available hedge prices and our operating strategy. During 2011, our commodity derivatives portfolio provided $22.2 million of cash inflows related to lower than anticipated prices received for our natural gas production and $1.4 million of cash inflows attributable to lower than anticipated prices received for our crude oil production.

In January 2012, we amended the Revolver to enhance our ability to hedge production. Previously, our hedging was limited to the lesser of certain fixed percentages of our reasonably anticipated production from proved developed reserves and total proved reserves. The amendment expands the potential volume subject to hedging to certain percentages of reasonably anticipated production from proved undeveloped reserves as well as proved developed reserves.

For 2012, we have hedged approximately 32% of our estimated natural gas production, at a weighted average floor/swap price and ceiling prices of between $5.43 and $6.05 per MMBtu. In addition, we have hedged approximately 47% of our estimated crude oil production for 2012, at weighted average floor/swap and ceiling prices of between $97.08 and $99.61 per barrel.

Cash Flows

The following table summarizes our statements of cash flows for the periods presented:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Variance
Cash flows from operating activities	$ 144,741	$ 79,839	$ 64,902
Cash flows from investing activities			
Capital expenditures – property and equipment	(445,623)	(405,994)	(39,629)
Proceeds from the sale of PVG units, net	—	139,120	(139,120)
Proceeds from sales of property and equipment and other, net	39,468	26,759	12,709
Net cash used in investing activities	(406,155)	(240,115)	(166,040)
Cash flows from financing activities			
Dividends paid	(10,316)	(10,271)	(45)
Proceeds from revolving credit facility borrowings, net	99,000	—	99,000
Proceeds from issuance of Senior Notes due 2019	300,000	—	300,000
Repurchase of Convertible Notes	(232,963)	—	(232,963)
Debt issuance costs paid	(8,854)	—	(8,854)
Proceeds from sale of PVG units, net	—	199,125	(199,125)
Distributions received from discontinued operations	—	11,218	(11,218)
Other, net	1,148	2,098	(950)
Net cash provided by financing activities	148,015	202,170	(54,155)
Net increase (decrease) in cash and cash equivalents	$(113,399)	$ 41,894	$(155,293)

Cash Flows From Operating Activities

The following table summarizes the most significant variances in our cash flows from operating activities:

Cash flows from operating activities for the year ended December 31, 2010	$ 79,839
Variances due to:	
Lower settlements from commodity derivatives portfolio	(9,918)
Higher interest payments, net of amounts capitalized	(960)
Lower restructuring costs paid	6,826
Lower tax payments	27,974
Transaction costs paid in connection with extinguishment of debt	(2,433)
Effect of higher operating margins, net of working capital changes	43,413
Cash flows from operating activities for the year ended December 31, 2011	$144,741

Due primarily to the realization of higher net margins on our expanding crude oil and NGL production, our cash flows from operating activities improved significantly during 2011 as compared to 2010. During 2011, we realized lower settlements from our commodity derivatives portfolio as compared to 2010 due primarily to higher realized natural gas prices as well as lower overall hedged production volume. Interest payments on our debt were higher during 2011 due to higher average outstanding balances partially offset by a favorable settlement of $2.9 million upon the termination of our interest rate swap. Restructuring costs paid were lower during 2011 as compared to 2010 due primarily to the larger scale of restructuring activities during 2010, which included, among other costs, a $3.5 million payment for the assignment of the lease of a former office. Income tax payments were significantly lower during 2011 as compared to 2010 as the prior year included higher income tax payments primarily attributable to the gain realized on the sale of our interests in PVG. During 2011, we paid incremental transaction costs in connection with the extinguishment of our Convertible Notes as well as costs attributable to the change in the composition of the bank syndicate in connection with the Revolver.

Cash Flows From Investing Activities

Capital expenditures were higher during 2011 due primarily to significant investment in our Eagle Ford Shale properties, including lease acquisition costs of approximately $30 million and development and exploratory drilling expenditures of approximately $372 million. Included in our capital expenditures for 2011 was approximately $12 million for proppant chemicals used in our well completion activities. These expenditures occurred near the end of 2011, and we are consuming these materials in connection with our 2012 capital projects. Previously, these products were provided by our well completion vendors in connection with their service offerings. Our purchase of these materials directly from product suppliers is expected to result in lower costs of well completions due to favorable pricing. Capital expenditures during 2010 included significant property acquisitions in the Marcellus Shale and our initial acreage in the Eagle Ford Shale as well as significant exploratory and development drilling expenditures primarily in the Granite Wash in the Mid-Continent region. These expenditures were partially offset during both years by proceeds received from the sale of non-core assets, mostly comprised of our Arkoma Basin assets in 2011 and our Gulf Coast assets in 2010. In addition, we received proceeds in 2010 from the sale of our remaining interests in PVG.

The following table sets forth costs related to our capital expenditure programs for the periods presented:

	Year Ended December 31,	
	2011	**2010**
Oil and gas:		
Development drilling	$307,779	$243,446
Exploration drilling	64,075	54,340
Seismic	11,202	10,168
Lease acquisitions, field projects and other	50,060	140,473
Pipeline and gathering facilities	12,484	1,407
	445,600	449,834
Other – Corporate	1,148	1,337
Total capital program costs	$446,748	$451,171

The following table reconciles the total costs of our capital expenditures programs with the net cash paid for capital expenditures for additions to property and equipment as reported in our Consolidated Statements of Cash Flows for the periods presented:

	Year Ended December 31,	
	2011	**2010**
Total capital program costs	$446,748	$451,171
Less:		
Exploration expenses		
Seismic	(11,202)	(10,168)
Other, primarily delay rentals	(2,183)	(2,379)
Other	(912)	—
Changes in accrued capitalized costs	(744)	(20,197)
Property received as consideration in sale transaction(1)	—	(8,204)
Add:		
Capitalized interest	1,983	1,384
Well materials purchased in advance of drilling	11,833	—
Other	100	(5,613)
Total cash paid for capital expenditures	$445,623	$405,994

(1) Represents property received in Mississippi in connection with the sale of our Gulf Coast properties.

Cash Flows From Financing Activities

Cash provided by financing activities during 2011 included the issuance of $300 million of 2019 Senior Notes, offset substantially by the repurchase of approximately 98% of our Convertible Notes and related transaction costs. During the third quarter of 2011, we began borrowing under our Revolver. In addition, we paid dividends totaling $10.3 million on our common stock.

During April 2010, we sold 11.25 million common units of PVG for proceeds of $199.1 million, net of offering costs, which reduced our limited partner interest in PVG to 22.6%. Because we maintained a controlling financial interest in PVG until the final sale, the proceeds from these transactions are reported as cash flows from financing activities. In addition, we received $11.2 million in distributions from PVG prior to our complete divestiture in 2010 as well as $2.1 million from the exercise of stock options by employees. We also paid dividends totaling $10.3 million on our common stock.

Financial Condition

As of February 21, 2012, we had approximately $11 million of cash on hand and $182.6 million of unused borrowing capacity under our Revolver. The borrowing capacity is determined by reducing the revolving commitment of $300 million by outstanding borrowings of $116.0 million and outstanding letters of credit of $1.4 million.

Debt and Credit Facilities

	As of December 31,	
	2011	2010
Revolving credit facility	$ 99,000	$ —
Senior notes due 2016, net of discount (principal amount of $300,000)	293,561	292,487
Senior notes due 2019	300,000	—
Convertible notes due 2012, net of discount (principal amount of $4,915 and $230,000)	4,746	214,049
	697,307	506,536
Less: Current portion of long-term debt	(4,746)	—
	$692,561	$506,536

Revolving Credit Facility. Borrowings under the Revolver bear interest, at our option, at either (i) a rate derived from LIBOR, as adjusted for statutory reserve requirements for Eurocurrency liabilities, or Adjusted LIBOR, plus an applicable margin ranging from 1.500% to 2.500% or (ii) the greater of (a) the prime rate, (b) the federal funds effective rate plus 0.5% or (c) the one-month Adjusted LIBOR plus 1.0%, and, in each case, plus an applicable margin (ranging from 0.500% to 1.500%). The applicable margin is determined based on the ratio of our outstanding borrowings to the available Revolver capacity. Commitment fees are being charged at 0.375% increasing to 0.500% on the undrawn portion of the Revolver as determined by our ratio of outstanding borrowings to the available Revolver capacity. As of December 31, 2011, the effective interest rate on the borrowings under the Revolver was 2.0625%.

The Revolver is guaranteed by Penn Virginia and the Guarantor Subsidiaries. The obligations under the Revolver are secured by a first priority lien on substantially all of our proved oil and gas reserves and a pledge of the equity interests in the Guarantor Subsidiaries.

2016 Senior Notes. The 2016 Senior Notes bear interest at an annual rate of 10.375% payable on June 15 and December 15 of each year. The 2016 Senior Notes were sold at 97% of par, equating to an effective yield to maturity of approximately 11%. The 2016 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the 2016 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

Under the Revolver, we are permitted under certain conditions to repurchase up to $100 million of the 2016 Senior Notes until August 2012. Accordingly, we may, from time to time, seek to repurchase the 2016 Senior Notes through open market purchases or privately negotiated transactions. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors.

2019 Senior Notes. The 2019 Senior Notes, which were issued at par in April 2011, bear interest at an annual rate of 7.25% payable on April 15 and October 15 of each year. The 2019 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the 2019 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

Convertible Notes. The Convertible Notes, which mature in November 2012, are convertible into cash up to the principal amount thereof and shares of our common stock, if any, in respect of the excess conversion value, based on an initial conversion rate of 17.3160 shares of common stock per $1,000 principal amount of the Convertible Notes (which is equal to an initial conversion price of approximately $57.75 per share of common stock), subject to adjustment. The Convertible Notes bear interest at an annual rate of 4.50% payable on May 15 and November 15 of each year.

The Convertible Notes are unsecured senior subordinated obligations, ranking junior in right of payment to any of our senior indebtedness and to any of our secured indebtedness to the extent of the value of the assets securing such indebtedness and equal in right of payment to any of our future unsecured senior subordinated indebtedness. The Convertible Notes will rank senior in right of payment to any of our future junior subordinated indebtedness and will structurally rank junior to all existing and future indebtedness of our Guarantor Subsidiaries.

In connection with a tender offer completed in April 2011, the Company repurchased $225.1 million aggregate principal amount of the Convertible Notes for $233.0 million reflecting a premium of $35 per $1,000 principal amount. The tender offer resulted in the extinguishment of approximately 98% of the outstanding Convertible Notes. The tender offer was funded with the net proceeds of the 2019 Senior Notes. Subsequent to the tender offer, a total of $4.9 million aggregate principal amount of Convertible Notes remain outstanding. The remaining unamortized discount will be amortized through November 2012.

Asset Dispositions

During 2011 and 2010, we completed a number of non-core asset dispositions in addition to other debt and capital raising activities in connection with a broader effort to supplement the funding of our capital expenditures program. The following table summarizes the net cash realized from these dispositions during the years ended December 31, 2011 and 2010:

	Year Ended December 31,	
Asset Description	**2011**	**2010**
PVG common units(1)	$ —	$338,245
Oil and gas properties	39,368	25,567
Other	100	1,192
	$39,468	$365,004

(1) Of the total received during 2010, $199.1 million has been reported as cash received from financing activities and $139.1 million has been reported as cash received from investing activities.

Covenant Compliance

Our Revolver requires us to maintain certain financial covenants as follows:

- Total debt to EBITDAX, each as defined in the Revolver, for any four consecutive quarters may not exceed 4.5 to 1.0 reducing to 4.0 to 1.0 for periods ending after June 30, 2013. EBITDAX, which is a non-GAAP measure, generally means net income plus interest expense, taxes, depreciation, depletion and amortization expenses, exploration expenses, impairments and other non-cash charges or losses.
- The current ratio, as of the last day of any quarter, may not be less than 1.0 to 1.0. The current ratio is generally defined as current assets to current liabilities. Current assets and current liabilities attributable to derivative instruments are excluded. In addition, current assets include the amount of any unused commitment under the Revolver.

As of December 31, 2011 and through the date upon which the Condensed Consolidated Financial Statements were issued, we were in compliance with these financial covenants.

The following table summarizes the actual results of our financial covenant compliance under the Revolver as of and for the period ended December 31, 2011:

Description of Covenant	Required Covenant	Actual Results
Total debt to EBITDAX	< 4.5 to 1	3.1 to 1
Current ratio	> 1.0 to 1	3.2 to 1

In the event that we would be in default of a covenant under the Revolver, we could request a waiver of the covenant from our bank group. Should the banks deny our request to waive the covenant requirement, the outstanding borrowings under the Revolver would become payable on demand and would be reclassified as a component of current liabilities on our Condensed Consolidated Balance Sheets.

In addition to the financial covenants, the Revolver imposes limitations on dividends as well as limits the ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, or enter into a merger or sale of our assets, including the sale or transfer of interests in our subsidiaries.

Future Capital Needs and Commitments

Subject to commodity prices and the availability of capital, we expect to expand our operations over the next several years by continuing to execute a program focused on development drilling and, to a lesser extent, exploration drilling, supplemented periodically with property and reserve acquisitions.

In 2012, we anticipate making capital expenditures, excluding any additional acquisitions, of up to approximately $325 million. The capital expenditures have been and will continue to be funded primarily by operating cash flows and borrowings under the Revolver. We expect to supplement these sources of liquidity with proceeds from the sale of non-core assets or by accessing the capital markets. However, there can be no assurance that such actions would be successful. We continually review drilling and other capital expenditure plans and may change the amount we spend in any area based on available opportunities, industry conditions, cash flows provided by operating activities and the availability of capital.

We expect to allocate approximately 85% of our capital expenditures to Eagle Ford Shale projects and approximately eight percent to projects, primarily non-operated development drilling, in the Mid-Continent region. The remainder will be allocated primarily to lease acquisitions, pipeline, gathering, seismic and facilities.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2011, the material off-balance sheet arrangements and transactions that we have entered into included operating lease arrangements, drilling commitments, hydraulic fracturing service commitments, firm transportation agreements and letters of credit, all of which are customary in our business. See Contractual Obligations summarized below for more details related to the value of off-balance sheet arrangements. We did not have any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We are, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2011:

	Payments Due by Period				
	Total	Less than 1 Year	1 – 3 Years	3 – 5 Years	More Than 5 Years
Revolver	$ 99,000	$ —	$ —	$ 99,000	$ —
Senior Notes due 2016(1)	293,561	—	—	293,561	—
Senior Notes due 2019	300,000	—	—	—	300,000
Convertible Notes(2)	4,746	4,746	—	—	—
Interest expense(3)	312,768	55,138	109,834	93,421	54,375
Asset retirement obligations(4)	6,283	—	—	—	6,283
Derivatives(5)	10,399	3,549	6,850	—	—
Rental commitments(6)	12,188	3,120	4,020	3,085	1,963
Firm transportation and drilling	89,441	34,075	15,001	9,408	30,957
Total contractual obligations(7)	$1,128,386	$100,628	$135,705	$498,475	$393,578

(1) Upon its maturity in June 2016, the principal amount of $300.0 million will be due.

(2) Upon its maturity in November 2012, the principal amount of $4.9 million will be due.

(3) Represents estimated interest payments that will be due under the 2016 Senior Notes and 2019 Senior Notes, the Convertible Notes and the Revolver. Interest payments on the Revolver were calculated by assuming that the December 31, 2011 outstanding balance of $99.0 million will remain outstanding through the August 2016 maturity date. A constant rate of 2.0625% was assumed. Actual results will differ from these estimates and assumptions.

(4) The undiscounted balance was approximately $36.7 million as of December 31, 2011.

(5) Represents estimated payments that we will make resulting from commodity derivatives.

(6) Relates primarily to equipment and building leases.

(7) Total contractual obligations do not include anticipated 2012 capital expenditures.

Environmental Matters

Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2011, we have recorded asset retirement obligations of $6.3 million attributable to these activities. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws, including any significant limitation on the use of hydraulic fracturing, have the potential to adversely affect our operations.

Critical Accounting Estimates

The process of preparing financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We consider the following to be the most critical accounting estimates requiring judgment of our management.

Oil and Gas Reserves

The estimates of oil and gas reserves are the single most critical estimate included in our Consolidated Financial Statements. Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments and the fair value of properties subject to potential impairments. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the amount and timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

There are several factors which could change our estimates of oil and gas reserves. Significant rises or declines in product prices could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2011, the costs attributable to unproved properties, net of accumulated amortization, were $120.3 million. Unproved properties whose acquisition costs are insignificant to total oil and gas properties are amortized as a component of exploration expense in the aggregate over the lesser of five years or the average remaining lease term. We assess unproved properties whose acquisition costs are relatively significant, if any, for impairment on a property-by-property basis. As exploration work progresses and the reserves on properties are proven, capitalized costs of these properties are subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work is charged to exploration expense. The timing of any write-downs of any significant unproved properties depends upon the nature, timing and extent of future exploration and development activities and their results.

Depreciation, Depletion and Amortization

We determine depreciation and depletion of oil and gas producing properties by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves. We compute depreciation and amortization of other property and equipment using the straight-line balance method over the estimated useful life of each asset.

Derivative Activities

From time to time, we enter into derivative instruments to mitigate our exposure to natural gas and crude oil price volatility and interest rate fluctuations. The derivative financial instruments, which are placed with financial institutions that we believe are acceptable credit risks, take the form of collars, swaps and swaptions, among others. All derivative instruments are recognized in our Consolidated Financial Statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices and rates. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

Deferred Tax Valuation Allowance

The Company records a valuation allowance to reduce its deferred tax assets to an amount that is more likely than not to be realized after consideration of future taxable income and reasonable tax planning strategies. In the event that the Company were to determine that it would not be able to realize all or a part of its deferred tax assets for which a valuation allowance had not been established, an adjustment to the deferred tax asset will be reflected in income in the period such determination is made. The most significant matter applicable to the realization of the Company's deferred tax assets is attributable to net operating losses in certain states. Estimates of future taxable income inherently reflect a significant degree of uncertainty. During the years ended December 31, 2011, 2010 and 2009, the Company increased the valuation allowance for its deferred tax assets due primarily to its inability to project sufficient future taxable income in certain states.

New Accounting Standards

During 2011, no new accounting standards were adopted or were pending adoption that would have a significant impact on our Consolidated Financial Statements and Notes to the Consolidated Financial Statements.

Item 7A *Quantitative and Qualitative Disclosures About Market Risk*

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and commodity price risk.

Interest Rate Risk

All of our long-term debt instruments, with the exception of the Revolver, have fixed interest rates. Accordingly, changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt instruments. However, changes in interest rates will affect the fair value of our long-term debt instruments. Our interest rate risk is attributable to our borrowings under the Revolver which is subject to variable interest rates. As of December 31, 2011, we had borrowings of $99 million outstanding under the Revolver at an interest rate of 2.0625%. Assuming a constant borrowing level of $99 million under the Revolver, an increase (decrease) in the interest rate of one percent would result in an increase (decrease) in interest expense approximately $1 million on an annual basis.

Commodity Price Risk

We produce and sell natural gas, crude oil and NGLs. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as collars, swaps and swaptions) to seek to mitigate the price risks associated with fluctuations in natural gas, crude oil and NGL prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of natural gas, crude oil and NGLs.

As of December 31, 2011, we reported a commodity derivative asset of $19.0 million. The contracts associated with this position are with six counterparties, all of which are investment grade financial institutions, and are substantially concentrated with three of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties. The maximum amount of loss due to credit risk if counterparties to our derivative asset positions fail to perform according to the terms of the contracts would be equal to the fair value of the contracts as of December 31, 2011.

In 2011, we reported net commodity derivative gains of $14.4 million. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our derivative instruments. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in natural gas, crude oil and NGL prices. These fluctuations could be significant in a volatile pricing environment. See Note 5 to the Condensed Consolidated Financial Statements for a further description of our price risk management activities.

The following table sets forth our commodity derivative positions as of December 31, 2011:

	Instrument	Average Volume Per Day	Weighted Average Price		Fair Value	
			Floor/Swap	Ceiling	Asset	Liability
		(in MMBtu)	($/MMBtu)			
Natural Gas:						
First quarter 2012	Collars	20,000	$ 6.00	$ 8.50	$5,394	$ —
First quarter 2012	Swaps	10,000	$ 5.10		1,880	—
Second quarter 2012	Swaps	20,000	$ 5.31		3,935	—
Third quarter 2012	Swaps	20,000	$ 5.31		3,706	—
Fourth quarter 2012	Swaps	10,000	$ 5.10		1,424	—
Crude Oil:		(barrels)	($/barrel)			
First quarter 2012	Collars	1,000	$ 90.00	$ 97.00	—	361
Second quarter 2012	Collars	1,000	$ 90.00	$ 97.00	—	447
Third quarter 2012	Collars	1,000	$ 90.00	$ 97.00	—	412
Fourth quarter 2012	Collars	1,000	$ 90.00	$ 97.00	—	350
First quarter 2013	Collars	1,000	$ 90.00	$100.00	—	146
Second quarter 2013	Collars	1,000	$ 90.00	$100.00	—	80
Third quarter 2013	Collars	1,000	$ 90.00	$100.00	—	14
Fourth quarter 2013	Collars	1,000	$ 90.00	$100.00	29	—
First quarter 2012	Swaps	1,400	$101.16		261	—
Second quarter 2012	Swaps	1,000	$100.61		106	—
Third quarter 2012	Swaps	500	$100.00		52	—
Fourth quarter 2012	Swaps	500	$100.00		88	—
First quarter 2013	Swaption	1,100	$100.00		—	1,049
Second quarter 2013	Swaption	1,000	$100.00		—	849
Third quarter 2013	Swaption	900	$100.00		—	674
Fourth quarter 2013	Swaption	750	$100.00		—	497
Premiums – Deferred					—	3,570
Settlements to be paid in subsequent period					162	—

The following table illustrates the estimated impact on the fair values of our derivative financial instruments and operating income attributable to hypothetical changes in the underlying commodity prices. This illustration assumes that natural gas prices, crude oil prices and production volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

	Change of \$1.00 per MMBtu of Natural Gas or \$10.00 per Barrel of Crude Oil (\$ in millions)	
	Increase	**Decrease**
Effect on the fair value of natural gas derivatives	\$ (6.3)	\$ 6.5
Effect on the fair value of crude oil derivatives	\$(12.1)	\$ 10.7
Effect on 2012 operating income, excluding natural gas derivatives	\$ 24.0	\$(24.1)
Effect on 2012 operating income, excluding crude oil derivatives	\$ 24.8	\$(24.7)

Item 8 ***Financial Statements and Supplemental Data***

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2011. We also have audited Penn Virginia Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Penn Virginia Corporation's management is responsible for these consolidated financial statements, 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 Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Penn Virginia Corporation and subsidiaries as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also in our opinion, Penn Virginia Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Houston, Texas
February 27, 2012

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31, 2011	2010	2009
Revenues			
Natural gas	$ 137,070	$ 171,141	$ 169,666
Crude oil	119,582	53,532	43,258
Natural gas liquids (NGLs)	43,394	26,663	15,735
Gain on sales of property and equipment	3,570	648	2,372
Other	2,389	2,454	4,175
Total revenues	306,005	254,438	235,206
Operating expenses			
Lease operating	36,988	35,757	44,392
Gathering, processing and transportation	15,157	14,180	11,307
Production and ad valorem taxes	13,690	13,917	15,044
General and administrative	48,328	58,383	49,690
Exploration	78,943	49,641	57,754
Depreciation, depletion and amortization	162,534	134,700	154,351
Impairments	104,688	45,959	106,415
Other	1,096	709	1,599
Total operating expenses	461,424	353,246	440,552
Operating loss	(155,419)	(98,808)	(205,346)
Other income (expense)			
Interest expense	(56,216)	(53,679)	(44,231)
Loss on extinguishment of debt	(25,421)	—	—
Derivatives	15,651	41,906	31,568
Other	335	2,403	1,259
Loss from continuing operations before income taxes	(221,070)	(108,178)	(216,750)
Income tax benefit	88,155	42,851	85,894
Loss from continuing operations	(132,915)	(65,327)	(130,856)
Income from discontinued operations, net of tax	—	33,448	53,488
Gain on sale of discontinued operations, net of tax	—	51,546	—
Net income (loss)	(132,915)	19,667	(77,368)
Less net income attributable to noncontrolling interests in discontinued operations	—	(28,090)	(37,275)
Loss attributable to Penn Virginia Corporation	$(132,915)	$ (8,423)	$(114,643)
Loss per share attributable to Penn Virginia Corporation – Basic:			
Continuing operations	$ (2.90)	$ (1.44)	$ (2.99)
Discontinued operations	—	0.12	0.37
Gain on sale of discontinued operations	—	1.13	—
Net loss	$ (2.90)	$ (0.19)	$ (2.62)
Loss per share attributable to Penn Virginia Corporation – Diluted:			
Continuing operations	$ (2.90)	$ (1.44)	$ (2.99)
Discontinued operations	—	0.12	0.37
Gain on sale of discontinued operations	—	1.13	—
Net loss	$ (2.90)	$ (0.19)	$ (2.62)
Weighted average shares outstanding, basic	45,784	45,553	43,811
Weighted average shares outstanding, diluted	45,784	45,553	43,811

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31,		
	2011	2010	2009
Net income (loss)	$(132,915)	$ 19,667	$ (77,368)
Other comprehensive income (loss):			
Unrealized gains (losses), net of tax of $62 in 2009	—	—	115
Hedging reclassification adjustments, net of tax of $1,986 in 2009	—	582	3,689
Total change in hedging derivative financial instruments	—	582	3,804
Change in pension and postretirement obligations, net of tax of ($79) in 2011, $188 in 2010 and $75 in 2009	(146)	348	140
	(146)	930	3,944
Comprehensive income (loss)	(133,061)	20,597	(73,424)
Less amounts attributable to noncontrolling interests:			
Net income	—	(28,090)	(37,275)
Other comprehensive income	—	(582)	(1,048)
Comprehensive loss attributable to Penn Virginia	$(133,061)	$ (8,075)	$(111,747)

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	As of December 31, 2011	As of December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 7,512	$ 120,911
Accounts receivable, net of allowance for doubtful accounts	72,432	72,378
Derivative assets	18,987	16,818
Income taxes receivable	31,465	—
Other current assets	14,950	4,233
Total current assets	145,346	214,340
Property and equipment, net (successful efforts method)	1,777,575	1,705,584
Derivative assets	—	3,889
Other assets	20,132	20,787
Total assets	$1,943,053	$1,944,600
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 94,504	$ 99,661
Derivative liabilities	3,549	388
Deferred income taxes	3,808	4,318
Income taxes payable	—	2,627
Current portion of long-term debt	4,746	—
Total current liabilities	106,607	106,994
Other liabilities	15,887	19,958
Derivative liabilities	6,850	—
Deferred income taxes	274,839	330,836
Long-term debt	692,561	506,536
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock of $100 par value – 100,000 shares authorized; none issued	—	—
Common stock of $0.01 par value – 128,000,000 shares authorized; shares issued of 45,714,191 and 45,556,854 as of December 31, 2011 and December 31, 2010, respectively	270	267
Paid-in capital	690,131	680,981
Retained earnings	157,242	300,473
Deferred compensation obligation	3,620	2,743
Accumulated other comprehensive loss	(1,084)	(938)
Treasury stock – 223,886 and 125,357 shares of common stock, at cost, as of December 31, 2011 and December 31, 2010, respectively	(3,870)	(3,250)
Total shareholders' equity	846,309	980,276
Total liabilities and shareholders' equity	$1,943,053	$1,944,600

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2011	**2010**	**2009**
Cash flows from operating activities			
Net loss	$(132,915)	$ 19,667	$ (77,368)
Adjustments to reconcile net loss to net cash provided by operating activities from continuing operations:			
Income from discontinued operations	—	(36,832)	(64,130)
Gain on sale of discontinued operations	—	(86,662)	—
Non-cash portion of loss on extinguishment of debt	22,456	—	—
Depreciation, depletion and amortization	162,534	134,700	154,351
Impairments	104,688	45,959	106,415
Derivative contracts:			
Net gains	(15,651)	(41,906)	(28,033)
Cash settlements	27,380	32,818	58,147
Deferred income taxes (benefit)	(85,501)	42,528	(83,222)
Loss (gain) on sales of property and equipment, net	(2,474)	61	(1,910)
Dry hole and unproved leasehold expense	60,940	36,275	33,278
Non-cash interest expense	6,807	11,984	10,202
Share-based compensation	7,430	7,811	9,127
Other, net	275	(209)	683
Changes in operating assets and liabilities:			
Accounts receivable, net	(1,792)	(19,964)	33,266
Accounts payable and accrued expenses	(6,552)	10,877	(20,066)
Other assets and liabilities	(2,884)	(77,268)	(13,007)
Net cash provided by operating activities from continuing operations	144,741	79,839	117,733
Cash flows from investing activities			
Capital expenditures – property and equipment	(445,623)	(405,994)	(205,676)
Proceeds from the sale of PVG units, net (Note 3)	—	139,120	—
Proceeds from sales of property and equipment, net	39,368	25,567	15,083
Other, net	100	1,192	11
Net cash used in investing activities for continuing operations	(406,155)	(240,115)	(190,582)
Cash flows from financing activities			
Dividends paid	(10,316)	(10,271)	(9,836)
Proceeds from revolving credit facility borrowings	114,000	—	87,000
Repayment of revolving credit facility borrowings	(15,000)	—	(419,000)
Proceeds from issuance of senior notes, net	300,000	—	291,009
Repurchase of Convertible Notes	(232,963)	—	—
Repayments of short-term borrowings	—	—	(7,542)
Debt issuance costs paid	(8,854)	—	(14,959)
Proceeds from the issuance of common stock, net	—	—	64,835
Proceeds from the sale of PVG units, net (Note 3)	—	199,125	118,080
Distributions received from discontinued operations	—	11,218	42,279
Other, net	1,148	2,098	—
Net cash provided by financing activities from continuing operations	148,015	202,170	151,866
Cash flows from discontinued operations			
Net cash provided by operating activities	—	77,759	158,214
Net cash used in investing activities	—	(18,112)	(80,506)
Net cash used in provided by financing activities	—	(59,647)	(77,708)
Net cash provided by discontinued operations	—	—	—
Net increase (decrease) in cash and cash equivalents	(113,399)	41,894	79,017
Cash and cash equivalents – beginning of period	120,911	79,017	—
Cash and cash equivalents – end of period	$ 7,512	$ 120,911	$ 79,017
Supplemental disclosures:			
Cash paid for:			
Interest (net of amounts capitalized)	$ 44,589	$ 43,531	$ 34,640
Income taxes (net of refunds received)	$ 210	$ 28,184	$ 9,443

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Shares Outstanding	Common Stock	Paid-in Capital	Retained Earnings	Deferred Compensation Obligation	Accumulated Other Comprehensive Loss	Treasury Stock	Total Penn Virginia Shareholders' Equity	Noncontrolling Interests	Total Shareholders' Equity
Balance as of December 31, 2008	41,871	$230	$485,967	$ 443,646	$2,237	$(4,182)	$(2,683)	$ 925,215	$ 297,227	$1,222,442
Net income (loss)	—	—	—	(114,643)	—	—	—	(114,643)	37,275	(77,368)
Change in hedging derivative financial instruments	—	—	—	—	—	2,756	—	2,756	1,048	3,804
Change in pension and postretirement obligations	—	—	—	—	—	140	—	140	—	140
Dividends paid ($0.225 per share)	—	—	—	(9,836)	—	—	—	(9,836)	—	(9,836)
Issuance of common stock	3,500	35	64,800	—	—	—	—	64,835	—	64,835
Common stock issued as compensation	3	—	60	—	—	—	—	60	—	60
Share-based compensation	—	—	9,062	—	—	—	—	9,062	—	9,062
Deferred compensation	12	—	11	—	186	—	(258)	(61)	—	(61)
Exercise of stock options	—	—	367	—	—	—	(386)	(19)	—	(19)
Sale of subsidiary units, net of tax (Notes 3, 13 and 19)	—	—	32,739	—	—	—	—	32,739	67,713	100,452
Unit-based compensation of subsidiaries	—	—	(833)	—	—	—	—	(833)	4,819	3,986
Distributions to noncontrolling interest holders	—	—	—	—	—	—	—	—	(78,171)	(78,171)
Other	—	—	(1,327)	—	—	—	—	(1,327)	—	(1,327)
Balance as of December 31, 2009	45,386	265	590,846	319,167	2,423	(1,286)	(3,327)	908,088	329,911	1,237,999
Net income (loss)	—	—	—	(8,423)	—	—	—	(8,423)	28,090	19,667
Change in hedging derivative financial instruments	—	—	—	—	—	—	—	—	582	582
Change in pension and postretirement obligations	—	—	—	—	—	348	—	348	—	348
Dividends paid ($0.225 per share)	—	—	—	(10,271)	—	—	—	(10,271)	—	(10,271)
Common stock issued as compensation	5	—	92	—	—	—	—	92	—	92
Share-based compensation	(2)	—	7,157	—	—	—	—	7,157	—	7,157
Deferred compensation	8	—	562	—	320	—	(309)	573	—	573
Exercise of stock options	136	1	1,712	—	—	—	386	2,099	—	2,099
Restricted stock unit vesting	24	1	201	—	—	—	—	202	—	202
Sale of subsidiary units, net of tax (Notes 3, 13 and 19)	—	—	82,915	—	—	—	—	82,915	70,188	153,103
Deconsolidation of subsidiaries (Notes 3, 13 and 19)	—	—	—	—	—	—	—	—	(382,325)	(382,325)
Unit-based compensation of subsidiaries	—	—	(1,267)	—	—	—	—	(1,267)	3,120	1,853
Distributions to noncontrolling interest holders	—	—	—	—	—	—	—	—	(49,566)	(49,566)
Other	—	—	(1,237)	—	—	—	—	(1,237)	—	(1,237)
Balance as of December 31, 2010	45,557	267	680,981	300,473	2,743	(938)	(3,250)	980,276	—	980,276
Net loss	—	—	—	(132,915)	—	—	—	(132,915)	—	(132,915)
Change in pension and postretirement obligations	—	—	—	—	—	(146)	—	(146)	—	(146)
Dividends paid ($0.225 per share)	—	—	—	(10,316)	—	—	—	(10,316)	—	(10,316)
Common stock issued as compensation	11	—	93	—	—	—	—	93	—	93
Share-based compensation	—	—	6,460	—	—	—	—	6,460	—	6,460
Deferred compensation	—	1	876	—	877	—	(620)	1,134	—	1,134
Exercise of stock options	95	1	1,225	—	—	—	—	1,226	—	1,226
Restricted stock unit vesting	51	1	270	—	—	—	—	271	—	271
Other	—	—	226	—	—	—	—	226	—	226
Balance as of December 31, 2011	45,714	$270	$690,131	$ 157,242	$3,620	$(1,084)	$(3,870)	$ 846,309	$ —	$ 846,309

See accompanying notes to consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation (''Penn Virginia,'' the ''Company,'' ''we,'' ''us'' or ''our'') is an independent oil and gas company primarily engaged in the exploration, development and production of natural gas and oil in various domestic onshore regions including Texas, Appalachia, the Mid-Continent and Mississippi.

2. Summary of Significant Accounting Policies

Principles of Consolidation

Our Consolidated Financial Statements include the accounts of Penn Virginia and all of its subsidiaries. Intercompany balances and transactions have been eliminated.

Use of Estimates

Preparation of our Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in our Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Derivative Instruments

From time to time, we utilize derivative instruments to mitigate our financial exposure to interest rates and natural gas and crude oil price volatility. The derivative instruments, which are placed with financial institutions that we believe are acceptable credit risks, take the form of collars, swaps and swaptions. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

All derivative instruments are recognized in the Consolidated Financial Statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. Our derivative instruments are not formally designated as hedges. We recognize changes in fair value in earnings currently as a component of the Derivatives caption on the Consolidated Statements of Operations. We have experienced and could continue to experience significant changes in the amount of unrealized derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts, which fluctuate with changes in natural gas and crude oil prices.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

2. Summary of Significant Accounting Policies – (continued)

Depreciation, depletion and amortization (''DD&A'') of proved producing properties is computed using the units-of-production method. Oil and natural gas liquids (''NGLs'') are converted to a gas equivalent on the basis that one barrel of liquids is equivalent to six thousand cubic feet of natural gas. Historically, we have adjusted our depletion rate throughout the year as new data becomes available and in the fourth quarter based on the year-end reserve report.

Impairment of Long-Lived and Other Assets

We review assets for impairment when events or circumstances indicate a possible decline in the recoverability of the carrying value of such property. If the carrying value of the asset is determined to be impaired, we reduce the asset to its fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and could include estimates of future production, commodity prices based on published forward commodity price curves as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

We review oil and gas properties for impairment periodically when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. Performing the impairment evaluations requires use of judgments and estimates since the results are dependent on future events. Such events include estimates of proved and possible reserves, future commodity prices and the timing of future production and capital expenditures, among others. We have recognized impairments of our properties in 2011, 2010 and 2009, as described in Note 16. We cannot predict whether impairment charges will be required in the future.

The costs of unproved leaseholds, including associated interest costs for the period activities were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. Unproved properties whose acquisition costs are insignificant to total oil and gas properties are amortized in the aggregate over the lesser of five years or the average remaining lease term and the amortization is charged to exploration expense. We assess unproved properties whose acquisition costs are relatively significant, if any, for impairment on a property-by-property basis. As exploration work progresses and the reserves on properties are proven, capitalized costs of these properties are subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work is charged to exploration expense. The timing of any write-downs of any significant unproved properties depends upon the nature, timing and extent of future exploration and development activities and their results.

Other Property and Equipment

Other property and equipment consists primarily of gathering systems and related support equipment. Property and equipment are carried at cost and include expenditures for additions and improvements, such as roads and land improvements, which increase the productive lives of existing assets. Maintenance and repair costs are charged to expense as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized.

2. Summary of Significant Accounting Policies – (continued)

We compute depreciation and amortization of property and equipment using the straight-line balance method over the estimated useful life of each asset as follows:

	Useful Life
Gathering systems	15 – 20 years
Other property and equipment	3 – 20 years

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation (''ARO'') in the period in which it is incurred. Associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our AROs relate to the plugging and abandonment of oil and natural gas wells and the associated asset is recorded as a component of oil and gas properties. After recording these amounts, the ARO is accreted to its future estimated value, and the additional capitalized costs are depreciated over the productive life of the assets. Both the accretion of the ARO and the depreciation of the related long-lived assets are included in DD&A expense on our Consolidated Statements of Operations.

Income Taxes

We recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Using this method, deferred tax liabilities and assets are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates. In assessing our deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of deferred tax assets is assessed periodically and is dependent upon the generation of future taxable income and our ability to utilize tax credits and operating loss carryforwards during the periods in which the temporary differences become deductible. We also consider the scheduled reversal of deferred tax liabilities and available tax planning strategies. We recognize interest attributable to income taxes, to the extent they arise, as a component of interest expense and penalties as a component of income tax expense.

Due to the geographical scope of our operations, we are subject to ongoing tax examinations in numerous domestic jurisdictions. Accordingly, we may record incremental tax expense based upon the more-likely-than-not outcomes of uncertain tax positions. In addition, when applicable, we adjust the previously recorded tax expense to reflect examination results when the position is effectively settled. Our ongoing assessments of the more-likely-than-not outcomes of the examinations and related tax positions require judgment and can increase or decrease our effective tax rate, as well as impact our operating results. The specific timing of when the resolution of each tax position will be reached is uncertain.

Revenue Recognition

We record revenues associated with sales of natural gas, crude oil, condensate and NGLs when title passes to the customer. We recognize natural gas sales revenues from properties in which we have an interest with other producers on the basis of our net revenue interest (''entitlement'' method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of natural gas production. We treat any amount received in excess of our share as a liability. If we take less than we are entitled to take, we record the under-delivery as a receivable. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production, particularly from properties that are operated by our partners. We

2. Summary of Significant Accounting Policies – (continued)

record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

Share-Based Compensation

We have stock compensation plans that allow incentive and nonqualified stock options, restricted stock and restricted stock units to be granted to key employees and officers and nonqualified stock options and deferred common stock units to be granted to directors. We measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award.

Recent Accounting Standards

During 2011, no new accounting standards were adopted or were pending adoption that would have a significant impact on our Consolidated Financial Statements and Notes to the Consolidated Financial Statements.

Reclassifications

Certain amounts for the 2010 and 2009 periods have been reclassified to conform to the current year presentation.

Subsequent Events

Management has evaluated all activities of the Company, through the date upon which the Consolidated Financial Statements were issued, and concluded that no subsequent events have occurred that would require recognition in the Consolidated Financial Statements or disclosure in the Notes to the Consolidated Financial Statements.

3. Acquisitions and Divestitures

In the following paragraphs, all references to crude oil and natural gas reserves and acreage acquired are unaudited. The factors we used to determine the fair market value of acquisitions include, but are not limited to, discounted future net cash flows on a risk-adjusted basis, comparable market data, geographic location, quality of resources and potential marketability.

Property Acquisitions

Eagle Ford and Marcellus Shale Property Acquisitions

During 2011, we acquired approximately 7,300 net Eagle Ford Shale acres in Gonzales County, Texas for approximately $27 million. The acreage acquired in these transactions is in close proximity to our initial 2010 Eagle Ford Shale acquisitions which was approximately 6,800 net acres for $31.1 million. We are the operator of all of the combined Gonzales County acreage with an average working interest of approximately 81%.

In December 2011, we entered into an agreement with a major oil and gas company to jointly explore approximately 13,000 gross acres of the Eagle Ford Shale in Lavaca County, Texas. The agreement establishes an area of mutual interest near our existing acreage in Gonzales County. Depending upon the future participation of other companies, our minimum working interest will be approximately 50%. Under the terms of the agreement, we must drill six wells by September 1, 2012 to earn our interest in the acreage. We will carry our counterparty on its working interest in the first three wells.

During 2010, we acquired a total of approximately 27,000 net acres in the Marcellus Shale play in Pennsylvania for approximately $69 million.

3. Acquisitions and Divestitures – (continued)

Divestitures

Oil and Gas Properties

In August 2011, we sold a substantial portion of our Arkoma Basin assets for approximately $30 million, excluding transaction costs and subject to customary purchase and sale adjustments. Upon the final settlement, we recognized an insignificant loss in connection with the transaction, following an impairment of approximately $71 million in the second quarter of 2011. The sale, which was effective July 1, 2011, included primarily natural gas and coal bed methane properties comprising approximately 73,000 net acres in Oklahoma and Texas with proved reserves of approximately 37.1 billion cubic feet of natural gas equivalent as well as related inventory and equipment.

In December 2011, we sold approximately 2,700 net undeveloped acres in Butler and Armstrong counties in Pennsylvania for proceeds of $8.1 million, net of transaction costs. We recognized a gain of $3.3 million in connection with this transaction. During 2011, we also received net proceeds of $1.2 million from the sale of various oil and gas assets in New York, Oklahoma, Pennsylvania and Texas.

In January 2010, we completed the sale of all of our oil and gas properties in the Gulf Coast region (southern Texas and Louisiana) for cash proceeds of $23.4 million, net of transaction costs and certain purchase and sale adjustments, and the receipt of certain oil and gas properties located in the Gwinville field in northern Mississippi valued at $8.2 million. During 2010, we also received net proceeds of $2.0 million from the sale of various oil and gas properties located in North Dakota, West Virginia and Oklahoma.

Penn Virginia GP Holdings, L.P. (“PVG”) Unit Offerings

In September 2009, we sold 10 million common units of PVG (“PVG Common Units”) owned by us for proceeds of $118.1 million, net of offering costs, resulting in a reduction of our limited partner interest in PVG from 77.0% to 51.4%. In April 2010, we completed the sale of an additional 11.25 million PVG Common Units for proceeds of $199.1 million, net of offering costs, which further reduced our limited partner interest to 22.6%. On a combined basis, these transactions resulted in a $137.9 million increase to noncontrolling interests as well as a $115.7 million increase to additional paid-in capital, net of income tax effects. Because we maintained a controlling financial interest in PVG, the proceeds received from these transactions were reported as cash flows from financing activities on our Consolidated Statements of Cash Flows.

In June 2010, we completed the sale of our remaining PVG Common Units for $139.1 million, net of offering costs. Immediately prior to the closing of the June offering, we contributed 100% of the membership interests in PVG’s general partner to PVG, thereby relinquishing control of PVG. As a result of this divestiture, we recognized a gain of $51.5 million, net of income tax effects of $35.1 million, which is reported in the “Gain on sale of discontinued operations, net of tax” caption on our Consolidated Statements of Operations. Because we no longer held any interests in PVG, the proceeds received from this transaction were reported as cash flows from investing activities on our Consolidated Statements of Cash Flows and we deconsolidated PVG from our Consolidated Financial Statements. We have reported PVG’s results of operations and cash flows as discontinued operations for the 2010 and 2009 periods. Additional information with respect to discontinued operations is provided in Note 19.

(in thousands, except per share amounts)

4. Accounts Receivable and Major Customers

The following table summarizes our accounts receivable by type as of the dates presented:

	As of December 31,	
	2011	2010
Customers	$49,763	$44,783
Joint interest partners	22,755	23,526
Other	1,695	4,442
	74,213	72,751
Less: Allowance for doubtful accounts	(1,781)	(373)
	$72,432	$72,378

For the years ended December 31, 2011 and 2010, five customers accounted for $173.1 million and $140.2 million, or approximately 58% and 56%, respectively, of our total consolidated product revenues. As of December 31, 2011 and 2010, $31.6 million and $31.1 million, or approximately 44% and 43%, respectively, of our consolidated accounts receivable, including joint interest billings, related to these customers. No significant uncertainties exist related to the collectability of amounts owed to us by these customers.

5. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to natural gas and crude oil price volatility as well as the volatility in interest rates attributable to our debt instruments. The derivative instruments, which are placed with financial institutions that we believe are acceptable credit risks, generally take the form of collars, swaps and swaptions. Our derivative instruments are not designated as hedges.

Commodity Derivatives

We utilize collars, swaps and swaptions to hedge against the variability in cash flows associated with anticipated sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

The counterparty to a collar or swap contract is required to make a payment to us if the settlement price for any settlement period is below the floor or swap price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling or swap price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. A swaption contract gives our counterparties the option to enter into a fixed price swap with us at a future date. If the forward commodity price for the term of the swaption is higher than or equal to the swaption strike price on the exercise date, the counterparty will exercise its option to enter into a fixed price swap at the swaption strike price for the term of the swaption, at which point the contract functions as a fixed price swap. If the forward commodity price for the term of the swaption is lower than the swaption strike price on the exercise date, the option expires and no fixed price swap is in effect.

We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of the end of the reporting period. The discounted cash flows utilize discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position, and our own credit risk if the derivative is in a liability position.

(in thousands, except per share amounts)

5. Derivative Instruments – (continued)

The following table sets forth our commodity derivative positions as of December 31, 2011:

	Instrument	Average Volume Per Day	Weighted Average Price		Fair Value	
			Floor/Swap	Ceiling	Asset	Liability
Natural Gas:		(in MMBtu)	($/MMBtu)			
First quarter 2012	Collars	20,000	$ 6.00	$ 8.50	5,394	—
First quarter 2012	Swaps	10,000	$ 5.10		1,880	—
Second quarter 2012	Swaps	20,000	$ 5.31		3,935	—
Third quarter 2012	Swaps	20,000	$ 5.31		3,706	—
Fourth quarter 2012	Swaps	10,000	$ 5.10		1,424	—
Crude Oil:		(barrels)	($/barrel)			
First quarter 2012	Collars	1,000	$ 90.00	$ 97.00	—	361
Second quarter 2012	Collars	1,000	$ 90.00	$ 97.00	—	447
Third quarter 2012	Collars	1,000	$ 90.00	$ 97.00	—	412
Fourth quarter 2012	Collars	1,000	$ 90.00	$ 97.00	—	350
First quarter 2013	Collars	1,000	$ 90.00	$100.00	—	146
Second quarter 2013	Collars	1,000	$ 90.00	$100.00	—	80
Third quarter 2013	Collars	1,000	$ 90.00	$100.00	—	14
Fourth quarter 2013	Collars	1,000	$ 90.00	$100.00	29	—
First quarter 2012	Swaps	1,400	$101.16		261	—
Second quarter 2012	Swaps	1,000	$100.61		106	—
Third quarter 2012	Swaps	500	$100.00		52	—
Fourth quarter 2012	Swaps	500	$100.00		88	—
First quarter 2013	Swaption	1,100	$100.00		—	1,049
Second quarter 2013	Swaption	1,000	$100.00		—	849
Third quarter 2013	Swaption	900	$100.00		—	674
Fourth quarter 2013	Swaption	750	$100.00		—	497
Premiums – Deferred(1)					—	3,570
Settlements to be paid in subsequent period					162	—

(1) Premiums are attributable to the crude oil collars for 2013 and are included in noncurrent derivative liabilities.

Interest Rate Swaps

In December 2009, we entered into an interest rate swap agreement to establish variable rates on approximately one-third of the face amount of the outstanding obligation under the 10.375% Senior Notes due 2016 (''2016 Senior Notes''). During August 2011, we terminated this agreement and received $2.9 million in cash proceeds.

(in thousands, except per share amounts)

5. Derivative Instruments – (continued)

The following table sets forth the terms and positions of our interest rate swaps as of the periods presented:

Term	Notional Amount	Swap Interest Rates[1]		Fair Value as of December 31,	
		Pay	Receive	2011	2010
Through June 2013	$100,000	LIBOR + 8.175%	10.375%	$ —	$2,590

(1) References to LIBOR represent the 3-month rate.

Financial Statement Impact of Derivatives

The impact of our derivatives activities on income is included in the Derivatives caption on our Consolidated Statements of Operations. The following table summarizes the effects of our derivative activities, for the periods presented:

	Year Ended December 31,		
	2011	2010	2009
Impact by contract type:			
Commodity contracts	$ 14,422	$36,693	$ 33,218
Interest rate contracts	1,229	5,213	(1,650)
	$ 15,651	$41,906	$ 31,568
Realized and unrealized impact:			
Cash received (paid) for:			
Commodity contract settlements	$ 23,562	$33,480	$ 59,908
Interest rate contract settlements	3,818	(662)	(1,761)
	27,380	32,818	58,147
Unrealized gains (losses) attributable to:			
Commodity contracts	(9,140)	3,213	(26,690)
Interest rate contracts	(2,589)	5,875	111
	(11,729)	9,088	(26,579)
	$ 15,651	$41,906	$ 31,568

The effects of derivative gains (losses) and cash settlements of our commodity and interest rate derivatives are reported as adjustments to reconcile net income (loss) to net cash provided by operating activities from continuing operations. These items are recorded in the ‘‘Derivative contracts: Net gains’’ and ‘‘Derivative contracts: Cash settlements’’ captions on our Consolidated Statements of Cash Flows.

(in thousands, except per share amounts)

5. Derivative Instruments – (continued)

The following table summarizes the fair value of our derivative instruments, as well as the locations of these instruments, on our Consolidated Balance Sheets as of the dates presented:

		Fair Values as of			
		December 31, 2011		December 31, 2010	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$18,987	$ 3,549	$15,075	$ 388
Interest rate contracts	Derivative assets/liabilities – current	—	—	1,743	—
		18,987	3,549	16,818	388
Commodity contracts	Derivative assets/liabilities – noncurrent	—	6,850	3,042	—
Interest rate contracts	Derivative assets/liabilities – noncurrent	—	—	847	—
		—	6,850	3,889	—
		$18,987	$10,399	$20,707	$ 388

As of December 31, 2011, we reported a commodity derivative asset of $19.0 million. The contracts associated with this position are with six counterparties, all of which are investment grade financial institutions, and are substantially concentrated with three of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

6. Property and Equipment

The following table summarizes our property and equipment as of the dates presented:

	As of December 31,	
	2011	2010
Oil and gas properties:		
Proved	$2,239,186	$2,021,729
Unproved	120,288	171,303
Total oil and gas properties	2,359,474	2,193,032
Other property and equipment	143,285	133,754
Total property and equipment	2,502,759	2,326,786
Accumulated depreciation, depletion and amortization	(725,184)	(621,202)
	$1,777,575	$1,705,584

The following table describes the changes in capitalized exploratory drilling costs that are pending the determination of proved reserves for the periods presented:

	2011		2010		2009	
	Number of Wells	Cost	Number of Wells	Cost	Number of Wells	Cost
Balance at beginning of year	1	$ 6,180	—	$ —	1	$ 2,482
Additions pending determination of proved reserves	—	—	1	6,180	—	—
Reclassification to wells, equipment and facilities based on the determination of proved reserves	—	—	—	—	(1)	(2,482)
Charged to exploration expense	(1)	(6,180)	—	—	—	—
Balance at end of year	—	$ —	1	$6,180	—	$ —

(in thousands, except per share amounts)

7. Asset Retirement Obligations

The following table reconciles our AROs for the periods presented, which are included in the Other liabilities caption on our Consolidated Balance Sheets:

	As of December 31,	
	2011	2010
Balance at beginning of year	$ 7,364	$6,835
Liabilities incurred	214	126
Liabilities settled	(183)	(41)
Sale of properties	(1,611)	—
Accretion expense	499	444
Balance at end of year	$ 6,283	$7,364

8. Long-Term Debt

The following table summarizes our long-term debt as of the dates presented:

	As of December 31,	
	2011	2010
Revolving credit facility	$ 99,000	$ —
Senior notes due 2016, net of discount (principal amount of $300,000)	293,561	292,487
Senior notes due 2019	300,000	—
Convertible notes due 2012, net of discount (principal amount of $4,915 and $230,000)	4,746	214,049
	697,307	506,536
Less: Current portion of long-term debt	(4,746)	—
	$692,561	$506,536

Revolving Credit Facility

In August 2011, we entered into a new five-year revolving credit facility (the ‘‘Revolver’’) maturing in August 2016. The Revolver provides for a $300 million revolving commitment, including a $20 million sublimit for the issuance of letters of credit. The Revolver has a borrowing base of $380 million. The borrowing base is redetermined semi-annually. There is an accordion feature that allows us to increase the commitment up to the lower of the borrowing base or $600 million upon receiving additional commitments from one or more lenders. The Revolver is available to us for general purposes including working capital, capital expenditures and acquisitions. We have letters of credit of $1.4 million outstanding as of December 31, 2011. As of December 31, 2011, our available borrowing capacity under the Revolver, as reduced by outstanding borrowings and such letters of credit, was $199.6 million.

Borrowings under the Revolver bear interest, at our option, at either (i) a rate derived from the London Interbank Offered Rate, as adjusted for statutory reserve requirements for Eurocurrency liabilities (the ‘‘Adjusted LIBOR’’), plus an applicable margin ranging from 1.500% to 2.500% or (ii) the greater of (a) the prime rate, (b) the federal funds effective rate plus 0.5% or (c) the one-month Adjusted LIBOR plus 1.0%, and, in each case, plus an applicable margin (ranging from 0.500% to 1.500%). The applicable margin is determined based on the ratio of our outstanding borrowings to the available Revolver capacity. Commitment fees are charged at 0.375% increasing to 0.500% on the undrawn portion of the Revolver as determined by our ratio of outstanding borrowings to the available Revolver capacity. As of December 31, 2011, the effective interest rate on the borrowings under the Revolver was 2.0625%.

8. Long-Term Debt – (continued)

The Revolver includes both current ratio and leverage ratio financial covenants. The current ratio is defined in the Revolver to include, among other things, adjustments for undrawn availability and may not be less than 1.0 to 1.0. The ratio of total net debt to EBITDAX, a non-GAAP financial measure defined in the Revolver, may not exceed 4.5 to 1.0 reducing to 4.0 to 1.0 for periods ending after June 30, 2013.

The Revolver is guaranteed by Penn Virginia and all of our material subsidiaries (''Guarantor Subsidiaries''). The obligations under the Revolver are secured by a first priority lien on substantially all of our proved oil and gas reserves and a pledge of the equity interests in the Guarantor Subsidiaries.

The guarantees provided by the Guarantor Subsidiaries under the Revolver as well as those provided for the senior indebtedness described below are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. The parent company and its non-guarantor subsidiaries have no material independent assets or operations. There are no significant restrictions on the ability of the parent company or any of the Guarantor Subsidiaries to obtain funds through dividends or other means, including advances and intercompany notes, among others.

2016 Senior Notes

The 2016 Senior Notes were originally sold at 97% of par equating to an effective yield to maturity of approximately 11%. The 2016 Senior Notes bear interest at an annual rate of 10.375% payable on June 15 and December 15 of each year. Beginning in June 2013, we may redeem all or part of the 2016 Senior Notes at a redemption price beginning at 105.188% of the principal amount and reducing to 100% in June 2015 and thereafter. The 2016 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the 2016 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

2019 Senior Notes

The Senior Notes due 2019 (''2019 Senior Notes''), which were issued at par in April 2011, bear interest at an annual rate of 7.25% payable on April 15 and October 15 of each year. Beginning in April 2015, we may redeem all or part of the 2019 Senior Notes at a redemption price beginning at 103.625% of the principal amount and reducing to 100% in June 2017 and thereafter. The 2019 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the 2019 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

Convertible Notes

The 4.50% Convertible Senior Subordinated Notes due 2012 (''Convertible Notes'') bear interest at an annual rate of 4.50% payable on May 15 and November 15 of each year. The Convertible Notes are convertible into cash up to the principal amount thereof and shares of our common stock, if any, in respect of the excess conversion value, based on an initial conversion rate of 17.3160 shares of common stock per $1,000 principal amount of the Convertible Notes (which is equal to an initial conversion price of approximately $57.75 per share of common stock), subject to adjustment. The Convertible Notes are unsecured senior subordinated obligations, ranking junior in right of payment to any of our senior indebtedness and to any of our secured indebtedness to the extent of the value of the assets securing such indebtedness and equal in right of payment to any of our future unsecured senior subordinated indebtedness. The Convertible Notes rank senior in right of payment to any of our future junior subordinated indebtedness and structurally rank junior to all existing and future indebtedness of our Guarantor Subsidiaries.

(in thousands, except per share amounts)

8. Long-Term Debt – (continued)

The Convertible Notes are represented by a liability component which is included in long-term debt, net of discount, and an equity component representing the convertible feature which is included in additional paid-in capital in shareholders' equity. The effective interest rate on the liability component of the Convertible Notes for all periods presented was 8.5%.

In connection with a tender offer completed in April 2011, the Company repurchased $225.1 million aggregate principal amount of the Convertible Notes for $233.0 million, representing a premium of $35 per $1,000 principal amount. The tender offer resulted in the extinguishment of approximately 98% of the outstanding Convertible Notes. The tender offer was funded with the net proceeds of the 2019 Senior Notes.

As a result of the tender offer, we recognized a pre-tax loss on extinguishment of debt of $25.9 million during the three months ended June 30, 2011, of which $24.2 million was charged to earnings and the remaining $1.7 million was charged directly to shareholders' equity. The loss charged to earnings was determined as follows:

Cash paid to repurchase principal:	
Allocated to liability component	$231,331
Allocated to equity component	1,632
	$232,963
Carrying value of liability component tendered:	
Principal amount of Convertible Notes tendered	$225,085
Pro rata share of original issue discount	(13,429)
	$211,656
Loss on extinguishment of debt:	
Excess of liability component over carrying value	$ 19,675
Write-off of pro rata share of debt issuance costs	2,147
Non-cash portion of loss on extinguishment	21,822
Transaction costs and fees paid	2,416
Pre-tax loss on extinguishment	$ 24,238

The following table summarizes the carrying amount of these components as of the dates presented:

	As of December 31, 2011	As of December 31, 2010
Principal	$ 4,915	$230,000
Unamortized discount	(169)	(15,951)
Net carrying amount of liability component	$ 4,746	$214,049
Carrying amount of equity component	$35,201	$ 36,850

The following table summarizes the amounts recognized as components of interest expense attributable to the Convertible Notes for the periods presented:

	Year Ended December 31, 2011	2010	2009
Contractual interest expense	$3,119	$10,350	$ 10,350
Accretion on original issue discount	2,353	7,371	6,782
Amortization of debt issuance costs	403	1,242	1,387
	$5,875	$18,963	$ 18,519

(in thousands, except per share amounts)

8. Long-Term Debt – (continued)

In connection with the original sale of the Convertible Notes, we entered into convertible note hedge transactions (''Note Hedges'') with respect to shares of our common stock with affiliates of certain of the underwriters of the Convertible Notes (collectively, the ''Option Counterparties''). The Note Hedges cover, subject to anti-dilution adjustments, the net shares of our common stock that would be deliverable to converting noteholders in the event of a conversion of the Convertible Notes.

We also entered into separate warrant transactions (''Warrants''), whereby we sold to the Option Counterparties warrants to acquire, subject to anti-dilution adjustments, approximately 3,982,680 shares of our common stock at an exercise price of $74.25 per share.

In August 2011, we entered into a partial unwind transaction with one of the Option Counterparties in which we received cash proceeds of less than $0.1 million. The transaction resulted in a reduction of the number of options outstanding attributable to the Note Hedges as well as a reduction in the number of outstanding Warrants. The effect of this transaction resulted in an increase to additional paid-in capital.

Debt Maturities

The following table sets forth the aggregate maturities of the principal amounts of our long-term debt for the next five years and thereafter:

Year	Amounts
2012	$ 4,746
2013	—
2014	—
2015	—
2016	392,561
Thereafter	300,000
Total	$697,307

9. Income Taxes

The following table summarizes our provision for income taxes from continuing operations for the periods presented:

	Year Ended December 31,		
	2011	2010	2009
Current income taxes (benefit)			
Federal	$ 1,279	$(109,240)	$ (2,158)
State	(3,933)	876	(514)
	(2,654)	(108,364)	(2,672)
Deferred income taxes (benefit)			
Federal	(80,529)	67,999	(68,488)
State	(4,972)	(2,486)	(14,734)
	(85,501)	65,513	(83,222)
	$(88,155)	$ (42,851)	$(85,894)

(in thousands, except per share amounts)

9. Income Taxes – (continued)

The following table summarizes the intra-period allocation of income taxes for the periods presented:

	Year Ended December 31,		
	2011	2010	2009
Continuing operations	$(88,155)	$(42,851)	$(85,894)
Discontinued operations	—	3,384	10,642
Gain on sale of discontinued operations	—	35,116	—
	$(88,155)	$ (4,351)	$(75,252)

The following table reconciles the difference between the income taxes computed by applying the statutory tax rate to income from continuing operations before income taxes and our reported income tax expense for the periods presented:

	Year Ended December 31,					
	2011		2010		2009	
Computed at federal statutory rate	$(77,374)	(35.0)%	$(37,862)	(35.0)%	$(75,863)	(35.0)%
State income taxes, net of federal income tax benefit	(4,825)	(2.2)%	(1,927)	(1.8)%	(8,020)	(3.7)%
Other, net	(5,956)	(2.7)%	(3,062)	(2.8)%	(2,011)	(0.9)%
	$(88,155)	(39.9)%	$(42,851)	(39.6)%	$(85,894)	(39.6)%

The following table summarizes the principal components of our net deferred income tax liability as of the dates presented:

	As of December 31,	
	2011	2010
Deferred tax liabilities:		
Property and equipment	$429,568	$352,431
Fair value of derivative instruments	3,006	2,215
Convertible notes	60	6,143
Total deferred tax liabilities	432,634	360,789
Deferred tax assets:		
Pension and postretirement benefits	3,046	3,951
Share-based compensation	8,838	7,602
Net operating loss carryforwards	150,953	27,915
Other	10,642	5,230
	173,479	44,698
Less: Valuation allowance	(19,492)	(19,063)
Total deferred tax assets	153,987	25,635
Net deferred tax liability	$278,647	$335,154

As shown in the table above, the Company has recognized $154.0 million of deferred tax assets as of December 31, 2011. Included in this total is a federal net operating loss carryforward of approximately $124 million, which expires in 2031, and state net operating loss carryforwards of approximately $27 million, which expire between 2024 and 2031. As of December 31, 2011 and 2010, valuation allowances of $19.5 million and $19.1 million, respectively, had been recorded for deferred tax assets associated with state net operating loss carryforwards that were not more-likely-than-not to be realized.

(in thousands, except per share amounts)

9. Income Taxes – (continued)

During 2011, the Company generated a net operating loss for federal income tax purposes. The net operating loss is expected to be carried back and applied against the taxable income of prior years. As of December 31, 2011, the Company classified $31.2 million of deferred tax assets as a current income tax receivable attributable to the federal net operating loss expected to be utilized in 2012.

The Company has no liability for unrecognized tax benefits as of December 31, 2011 and 2010. There were no interest and penalty charges recognized during the years ended December 31, 2011 and 2010. For the year ended December 31, 2009 we recognized $2.1 million in interest and penalties. Tax years from 2008 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

10. Additional Balance Sheet Detail

The following table summarizes components of selected balance sheet accounts as of the dates presented:

	As of December 31,	
	2011	2010
Other current assets:		
Tubular inventory and well materials	$14,251	$ 3,600
Prepaid expenses	699	633
	$14,950	$ 4,233
Other assets:		
Debt issuance costs	$16,993	$14,300
Long-term investments – Rabbi Trust(1)	3,088	6,440
Other	51	47
	$20,132	$20,787
Accounts payable and accrued liabilities:		
Trade accounts payable	$30,186	$33,831
Drilling costs	30,948	31,770
Royalties	15,235	9,308
Production and franchise taxes	3,495	6,012
Compensation(2),(3)	5,186	9,631
Interest	5,964	2,977
Other	3,490	6,132
	$94,504	$99,661
Other liabilities:		
Asset retirement obligations	$ 6,283	$ 7,364
Defined benefit pension obligations(2)	1,763	1,766
Postretirement health care benefit obligations(2)	3,022	2,976
Deferred compensation(1)	3,172	6,952
Other	1,647	900
	$15,887	$19,958

(1) Represents the assets and liabilities of the Company's nonqualified supplemental employee retirement savings plan. Assets of the plan are held in a Rabbi Trust. Shares of the Company's common stock held by the Rabbi Trust are presented as Treasury stock carried at cost.

(in thousands, except per share amounts)

10. Additional Balance Sheet Detail – (continued)

(2) Includes the combined unfunded benefit obligations under the Company's defined benefit pension and postretirement health care plans of $5.4 million as of December 31, 2011 and 2010. The expense recognized with respect to these plans was $0.4 million, $0.6 million and $0.6 million, for the years ended December 31, 2011, 2010 and 2009, respectively.

(3) Includes employer matching obligations under the Company's defined contribution retirement plan of $0.3 million as of December 31, 2011 and 2010. The expense recognized with respect to this plan was $1.2 million, $1.7 million and $2.3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

11. Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We use a hierarchy that prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

Fair value measurements are classified and disclosed in one of the following three categories:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- Level 2: Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3: Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

Our financial instruments that are subject to fair value disclosure consist of cash and cash equivalents, accounts receivable, accounts payable, derivatives and long-term debt. As of December 31, 2011, the carrying values of all of these financial instruments, except the portion of long-term debt with fixed interest rates, approximated fair value.

The following table summarizes the fair value of our long-term debt with fixed interest rates, which is estimated based on the published market prices for these debt obligations as of the dates presented:

	December 31, 2011		December 31, 2010	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Notes due 2016	$319,500	$293,561	$335,712	$292,487
Senior Notes due 2019	280,500	300,000	—	—
Convertible Notes	4,925	4,746	225,975	214,049
	$604,925	$598,307	$561,687	$506,536

(in thousands, except per share amounts)

11. Fair Value Measurements – (continued)

Recurring Fair Value Measurements

Certain financial assets and liabilities are measured at fair value on a recurring basis in our Consolidated Balance Sheets. The following tables summarize the valuation of those assets and liabilities as of the dates presented:

	As of December 31, 2011			
		Fair Value Measurement Classification		
Description	Fair Value Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets – current	$18,987	$ —	$18,987	$ —
Commodity derivative assets – noncurrent	—	—	—	—
Long-term investments – Rabbi Trust	3,088	3,088	—	—
Liabilities:				
Commodity derivative liabilities – current	(3,549)	—	(3,549)	—
Commodity derivative liabilities – noncurrent	(6,850)	—	(6,850)	—
Deferred compensation – noncurrent	(3,168)	(3,168)	—	—
Totals	$ 8,508	$ (80)	$ 8,588	$ —

	As of December 31, 2010			
		Fair Value Measurement Classification		
Description	Fair Value Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets – current	$15,075	$ —	$15,075	$ —
Commodity derivative assets – noncurrent	3,042	—	3,042	—
Interest rate swap assets – current	1,743	—	1,743	—
Interest rate swap assets – noncurrent	847	—	847	—
Long-term investments – Rabbi Trust	6,440	6,440	—	—
Liabilities:				
Commodity derivative liabilities – current	(388)	—	(388)	—
Deferred compensation – noncurrent	(6,948)	(6,948)	—	—
Totals	$19,811	$ (508)	$20,319	$ —

We used the following methods and assumptions to estimate fair values for the financial assets and liabilities described below:

- Commodity derivatives: We determine the fair values of our oil and gas derivative instruments based on discounted cash flows derived from third-party quoted forward prices for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of the end of the reporting periods. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. Each of these is a level 2 input.

(in thousands, except per share amounts)

11. Fair Value Measurements – (continued)

- Interest rate swaps: We determine the fair values of our interest rate swaps using an income approach valuation technique that connects future cash flows to a single discounted value. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. Each of these is a level 2 input.
- Long-term investments — Rabbi Trust: We hold various publicly traded equity securities in a Rabbi Trust as assets for funding certain deferred compensation obligations. The fair values are based on quoted market prices, which are level 1 inputs.
- Deferred compensation: Certain of our deferred compensation obligations are ultimately to be settled in cash based on the underlying fair value of certain assets, including those held in the Rabbi Trust. The fair values are based on quoted market prices, which are level 1 inputs.

Non-Recurring Fair Value Measurements

The most significant non-recurring fair value measurements include the fair value of proved properties, tubular inventory and well materials for purposes of impairment testing and the initial determination of AROs. The factors used to determine fair value for purposes of impairment testing include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Because these significant fair value inputs are typically not observable, we have categorized the amounts as level 3 inputs.

The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial fair value estimates as level 3 inputs.

In addition to these non-recurring fair value measurements, we utilized fair value measurements in the determination of the loss on the extinguishment of approximately 98% of our Convertible Notes. In connection with that determination, we were required to allocate the cash paid to repurchase the Convertible Notes to its liability and equity components. The allocation to the liability component was based on the fair value of a comparable debt instrument that has no conversion feature. The residual amount of cash paid to repurchase the Convertible Notes was allocated to the equity component.

12. Commitments and Contingencies

The following table sets forth our significant commitments as of December 31, 2011, by category, for the next five years and thereafter:

Year	Minimum Rental Commitments	Drilling Commitments	Firm Transportation Commitments
2012	$ 3,120	$23,820	$10,255
2013	2,283	59	8,805
2014	1,737	—	6,137
2015	1,628	—	5,137
2016	1,456	—	4,271
Thereafter	1,963	—	30,957
Total	$12,187	$23,879	$65,562

12. Commitments and Contingencies – (continued)

Rental Commitments

Operating lease rental expense in the years ended December 31, 2011, 2010 and 2009 was $11.4 million, $14.8 million and $18.0 million, respectively, related primarily to field equipment, office equipment and office leases.

Drilling Commitments

We have agreements to purchase oil and gas well drilling services from third parties with original terms of up to three years. The agreements include early termination provisions that would require us to pay penalties if we terminate the agreements prior to the end of their original terms. The amount of penalty is based on the number of days remaining in the contractual term and declines as time passes. As of December 31, 2011, the penalty amount would have been $14.1 million if we had terminated our agreements on that date.

Firm Transportation Commitments

We have entered into contracts that provide firm transportation capacity rights for specified volumes per day on various pipeline systems with terms that range from one to 15 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

Legal

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. During 2011, we recorded a $0.2 million reserve for litigation attributable to certain properties that were previously sold. This litigation was settled in January 2012 for the recorded amount. During 2010, we established a $0.9 million reserve for a litigation matter pertaining to certain properties that remains outstanding as of December 31, 2011. During 2010, we also established a $0.5 million reserve for a sales tax audit contingency, which was ultimately resolved during 2011 for $0.3 million.

Environmental Compliance

Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2011, we have recorded AROs of $6.3 million attributable to these activities. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws, including any significant limitation on the use of hydraulic fracturing, have the potential to adversely affect our operations.

13. Shareholders' Equity

Common Stock

In May 2010, the shareholders of the Company approved an increase in the authorized number of shares of common stock from 64 million to 128 million shares.

In May 2009, we issued 3,500,000 shares of our common stock in a registered public offering that provided $64.8 million of net proceeds. The net proceeds were used, in addition to the proceeds from the issuance of the Senior Notes due 2016, to repay borrowings under our previous revolving credit facility.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive losses are entirely attributable to our pension and postretirement benefit obligations. The accumulated losses, net of tax, were $1.1 million, $0.9 million and $1.3 million as of December 31, 2011, 2010 and 2009, respectively.

Treasury Stock

We maintain nonqualified deferred compensation supplemental retirement savings plans for certain employees and directors. Participants in the plans may defer and contribute a portion of their compensation to a Rabbi Trust. We include the assets and liabilities of the supplemental retirement savings plans on our Consolidated Balance Sheets. Shares of the Company's common stock purchased under the non-qualified deferred compensation plans are held in the Rabbi Trust and are presented as treasury stock carried at cost. A total of 223,886 and 125,357 shares have been recorded as treasury stock as of December 31, 2011 and 2010, respectively.

Noncontrolling Interests

In connection with the sale of our remaining PVG Common Units (Note 3), we deconsolidated PVG from our Consolidated Financial Statements resulting in the elimination of PVG's assets and liabilities as well as the related noncontrolling interests from our Consolidated Balance Sheet and Consolidated Statements of Shareholders' Equity and Comprehensive Income.

Prior to the final sale of our PVG Common Units, we reduced our limited partner interest in PVG during 2010 and 2009 while still maintaining control. In April 2010, we completed the sale of 11.25 million units of PVG owned by us for proceeds of $199.1 million, net of offering costs reducing our limited partner interest in PVG from 51.4% to 22.6%. The transaction resulted in a $70.2 million increase in noncontrolling interests and an $82.9 million increase to additional paid-in capital, net of income tax effects. In September 2009, we sold 10 million units of PVG for proceeds of $118.1 million, net of offering costs reducing our limited partner interest in PVG from 77.0% to 51.4%. The transaction resulted in a $67.7 million increase in noncontrolling interests and a $32.7 million increase to additional paid-in capital, net of income tax effects.

14. Share-Based Compensation

We have stock compensation plans (collectively, the "Stock Compensation Plans") that allow incentive and nonqualified stock options, restricted stock and restricted stock units to be granted to key employees and officers and nonqualified stock options and deferred common stock units to be granted to directors. As of December 31, 2011, there were approximately 2,227,554 and 196,314 shares available for issuance to employees and directors, respectively, pursuant to the Stock Compensation Plans.

(in thousands, except per share amounts)

14. Share-Based Compensation – (continued)

The following table summarizes the share-based compensation expense recognized for the periods presented:

	Year Ended December 31,		
	2011	2010	2009
Stock option plans	$5,477	$5,828	$6,602
Common, deferred, restricted and restricted unit plans	1,953	1,983	2,525
	$7,430	$7,811	$9,127

Stock Options

The exercise price of all options granted under the Stock Compensation Plans is equal to the fair market value of our common stock on the date of the grant. Options may be exercised at any time after vesting and prior to ten years following the date of grant. Options vest upon terms established by the compensation and benefits committee of our board of directors (the ''Committee''). Generally, options vest over a three-year period, with one-third vesting in each year. In addition, all options will vest upon a change of control of the Company, as defined in the Stock Compensation Plans. In the case of employees, if a grantee's employment terminates (i) for cause, all of the grantee's options, whether vested or unvested, will be automatically forfeited, (ii) by reason of death, disability or retirement after becoming retirement eligible (age 62 and providing ten consecutive years of service) the grantee's options will automatically vest and (iii) for any other reason, the grantee's unvested options will be automatically forfeited. In the case of directors, if a grantee's membership on our board of directors terminates for any reason, the grantee's unvested options will be automatically forfeited. We have consistently issued new shares to satisfy share option exercises.

The fair value of each option award is estimated on the date of grant using the Black-Scholes-Merton option-pricing formula that uses the assumptions noted in the following table. Expected volatilities are based on historical changes in the market value of our stock. Separate groups of employees that have similar historical exercise behavior are considered separately to estimate expected lives. Options granted have a maximum term of ten years. We base the risk-free interest rate on the U.S. Treasury rate for the week of the grant having a term equal to the expected life of the option.

	2011	2010	2009
Expected volatility	61.7% to 71.9%	59.5% to 67.6%	51.7% to 64.9%
Dividend yield	1.25% to 2.25%	0.90% to 1.20%	1.25% to 1.49%
Expected life	3.5 to 4.6 years	3.5 to 4.6 years	3.5 to 4.6 years
Risk-free interest rate	0.39% to 2.18%	0.68% to 2.30%	1.23% to 1.84%

The following table summarizes activity for our most recent fiscal year with respect to awarded options:

	Shares Under Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at beginning of year	2,144,357	$24.70		
Granted	830,021	16.98		
Exercised	(95,516)	11.89		
Forfeited	(403,788)	23.26		
Outstanding at end of year	2,475,074	$22.84	7.4	$ 67
Exercisable at end of year	1,352,273	$26.74	6.4	$ 12

(in thousands, except per share amounts)

14. Share-Based Compensation – (continued)

The weighted-average grant-date fair value of options granted during the years ended December 31, 2011, 2010 and 2009 was $7.30, $10.13 and $5.60 per option. The total intrinsic value of options exercised during the years ended December 31, 2011 and 2010 was $0.4 million and $1.2 million. There were no options exercised during 2009.

As of December 31, 2011, we had $6.5 million of unrecognized compensation cost related to unvested stock options. We expect that cost to be recognized over a weighted-average period of 0.9 years. The total grant-date fair values of stock options that vested in 2011, 2010 and 2009 were $3.7 million, $4.6 million and $5.7 million, respectively.

Restricted Stock

Restricted stock vests upon terms established by the Committee and as specified in the award agreement. In addition, all restricted stock will vest upon a change of control of the Company. If a grantee's employment terminates for any reason other than death or disability, the grantee's restricted stock will be automatically forfeited unless otherwise determined by the Committee and specified in the award agreement. If a grantee's employment terminates by reason of death or disability, or if a grantee becomes retirement eligible, the grantee's restricted stock will automatically vest. Except as specified by the Committee, a grantee shall be entitled to receive any dividends declared on our common stock. Restricted stock vests generally over a three-year period, with one-third vesting in each year. We recognize compensation expense on a straight-line basis over the vesting period.

The following table summarizes activity for our most recent fiscal year with respect to awarded nonvested restricted stock:

	Nonvested Restricted Stock	Weighted-Average Grant Date Fair Value
Balance at beginning of year	5,957	$42.27
Vested	(5,957)	42.27
Balance at end of year	—	$ —

The total grant-date fair values of restricted stock that vested in 2011, 2010 and 2009 were $0.3 million, $0.5 million and $1.3 million, respectively.

Deferred Common Stock Units

A portion of the compensation paid to non-employee members of our board of directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, vests immediately upon issuance, and is available to the holder upon termination or retirement from our board of directors. Deferred common stock units awarded to directors receive all cash or other dividends we pay on shares of our common stock.

The following table summarizes activity for our most recent fiscal year with respect to awarded deferred common stock units:

	Deferred Common Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	103,256	$26.76
Granted	105,527	8.31
Balance at end of year	208,783	$17.34

(in thousands, except per share amounts)

14. Share-Based Compensation – (continued)

As of December 31, 2011, 2010 and 2009, shareholders' equity included deferred compensation obligations of $3.6 million, $2.7 million and $2.4 million, respectively, and corresponding amounts for treasury stock.

Restricted Stock Units

A restricted stock unit entitles the grantee to receive a share of common stock upon the vesting of the restricted stock unit or, at the discretion of the Committee, the cash equivalent of the fair market value of a share of common stock. The Committee determines the time period over which restricted stock units granted to employees and directors will vest. In addition, all restricted stock units will vest upon a change of control of the Company. If an employee's employment with us or our affiliates terminates for any reason other than death, disability or retirement after becoming retirement eligible, the grantee's restricted stock units will be automatically forfeited unless, and to the extent, the Committee provides otherwise. Restricted stock units generally vest over a three-year period, with one-third vesting in each year. The Committee, in its discretion, may grant tandem dividend equivalent rights with respect to restricted stock units. A dividend equivalent right is a right to receive an amount in cash equal to, and 30 days after, the cash dividends made with respect to a share of common stock during the period such restricted stock unit is outstanding. Payments of dividend equivalent rights associated with restricted stock units that are expected to vest are recorded as dividends; payments associated with restricted stock units that are not expected to vest are recorded as compensation expense.

The following table summarizes activity for our most recent fiscal year with respect to awarded restricted stock units:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year[(1)]	72,215	$18.77
Granted	78,763	17.14
Vested	(51,152)	18.38
Balance at end of year[(1)]	99,826	$18.10

(1) Excludes 61,344 units at both the beginning and end of year that have vested due to retirement eligibility, but have not yet been settled or converted to common shares.

As of December 31, 2011, we had $1.4 million of unrecognized compensation cost attributable to nonvested restricted stock units. We expect that cost to be recognized over a weighted-average period of 0.8 years. The total grant-date fair values of restricted stock units that vested in 2011, 2010 and 2009 were $0.9 million, $0.9 million and $0.6 million, respectively.

15. Restructuring Activities

During 2011, we completed an organizational restructuring due primarily to our decision to exit the Arkoma Basin and to consolidate certain operations functions to our Houston, Texas location. This restructuring and consolidation resulted in the termination of approximately 40 employees, most of whom were based out of our Tulsa, Oklahoma office, as well as certain corporate positions in connection with a reallocation of administrative responsibilities. In addition, we closed our regional office in Tulsa, Oklahoma during the fourth quarter of 2011and recorded a charge in connection with the long-term lease of that office.

During 2009 and 2010, we implemented an organization restructuring in connection with our transformation to a pure play development, exploration and production company. The restructuring resulted in the termination of approximately 30 employees and the transfer of certain corporate and division operations functions from our former Kingsport, Tennessee location to our Houston, Texas and Pittsburgh and Radnor,

(in thousands, except per share amounts)

15. Restructuring Activities – (continued)

Pennsylvania locations. We incurred special termination benefit costs, relocation costs and other incremental costs associated with staffing and expanding our office locations.

These restructuring charges are included in the General and administrative expenses caption on our Consolidated Statements of Operations and are comprised of the following for the periods presented:

	Year Ended December 31,		
	2011	2010	2009
Termination benefits	$ 1,463	$ 2,081	$ 529
Employee and office relocation costs	322	1,597	—
Other incremental costs	—	1,022	—
Facility lease-related charges	566	3,500	—
	$ 2,351	$ 8,200	$ 529

The following table summarizes our restructuring-related obligations as of and for the years ended December 31:

	2011	2010	2009
Balance at beginning of period	$ 64	$ 529	$ —
Termination benefits accrued	1,463	2,081	529
Employee, office and other costs accrued	888	6,119	—
Cash payments	(1,839)	(8,665)	—
Balance at end of period	$ 576	$ 64	$ 529

16. Impairments

The following table summarizes impairment charges recorded during the periods presented:

	Year Ended December 31,		
	2011	2010	2009
Oil and gas properties	$104,688	$43,067	$102,332
Other – tubular inventory and well materials	—	2,892	4,083
	$104,688	$45,959	$106,415

During 2011, we recognized an impairment of our Arkoma Basin assets for $71.1 million, which was triggered by the expected disposition of these high-cost gas properties. As disclosed in Note 3, we completed the sale of these properties in August 2011. Also during 2011, we recognized an impairment of our horizontal coal bed methane properties in the Appalachian region for $26.6 million and certain dry-gas properties in Mississippi for $7.0 million due primarily to market declines in gas prices. During 2010, we incurred impairment charges related to our Mid-Continent coal bed methane properties as a result of market declines in gas prices and to an area in the Anadarko Basin of the Mid-Continent region where we drilled an uneconomic well. In addition, we recorded impairment charges attributable to certain oil and gas inventory assets triggered primarily by declines in asset quality. During 2009, we incurred impairment charges in connection with the initial classification of our Gulf Coast properties as assets held for sale at their fair value less costs to sell, as well as impairments attributable to tubular inventory and other oil and gas properties.

(in thousands, except per share amounts)

17. Interest Expense

The following table summarizes the components of interest expense for the periods presented:

	Year Ended December 31, 2011	2010	2009
Interest on borrowings and related fees	$ 51,384	$ 43,060	$ 33,374
Accretion on original issue discount	3,427	8,109	7,523
Amortization of debt issuance costs	3,380	3,875	2,679
Interest rate swaps	—	—	3,969
Capitalized interest	(1,983)	(1,384)	(2,318)
Other, net	8	19	(996)
	$ 56,216	$ 53,679	$ 44,231

18. Earnings per Share

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings per share for the periods presented:

	Year Ended December 31, 2011	2010	2009
Loss from continuing operations	$(132,915)	$(65,327)	$(130,856)
Income from discontinued operations, net of tax[(1)]	—	33,448	53,488
Gain on sale of discontinued operations, net of tax	—	51,546	—
Less net income attributable to noncontrolling interests	—	(28,090)	(37,275)
Loss attributable to common shareholders	$(132,915)	$ (8,423)	$(114,643)
Less: Portion of subsidiary net income allocated to undistributed share-based compensation awards, net of tax	—	(28)	(116)
	$(132,915)	$ (8,451)	$(114,759)
Weighted-average shares, basic	45,784	45,553	43,811
Effect of dilutive securities[(2)]	—	—	—
Weighted-average shares, diluted	45,784	45,553	43,811

(1) For purposes of determining earnings per share, net income attributable to noncontrolling interests is applied against income from discontinued operations as both are completely attributable to PVG's operations.

(2) For 2011, 2010 and 2009, an amount less than 0.1 million, approximately 0.2 million and 0.1 million potentially dilutive securities, including the Convertible Notes, stock options, restricted stock and restricted stock units had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share.

19. Discontinued Operations

Prior to June 2010, we indirectly owned partner interests in Penn Virginia Resource Partners, L.P. ("PVR"), a publicly traded limited partnership formed by us in 2001. Our ownership interests in PVR were held principally through our general and limited partner interests in PVG. During June 2010, we disposed of our remaining ownership interests in PVG and, indirectly, our interests in PVR.

Income from discontinued operations represents the results of operations of PVG, which include the results of operations of PVR. Previously, the results of operations of PVG and PVR were presented as our coal and natural resource management and natural gas midstream segments.

(in thousands, except per share amounts)

19. Discontinued Operations – (continued)

The disclosures for the 2010 period provided in the table below reflect the results of operations of PVG through the date of the disposition of our entire remaining interest in PVG on June 7, 2010.

	Year Ended December 31,		
	2011	2010	2009
Revenues	$ —	$303,206	$579,931
Income from discontinued operations before taxes	$ —	$ 36,832	$ 64,130
Income tax expense[(1)]	—	(3,384)	(10,642)
Income from discontinued operations, net of taxes	$ —	$ 33,448	$ 53,488

(1) Determined by applying the effective tax rate attributable to discontinued operations to the income from discontinued operations less noncontrolling interests that are fully attributable to PVG's operations.

The following table summarizes the determination of the gain recognized in 2010 upon the disposition of PVG:

Cash proceeds, net of offering costs (8,827,429 units × $15.76 per unit)	$ 139,120
Carrying value of noncontrolling interests in PVG at date of disposition	382,324
	521,444
Less: Carrying value of PVG's assets and liabilities at date of disposition	(434,782)
	86,662
Income tax expense	(35,116)
Gain on sale of discontinued operations, net of tax	$ 51,546

During 2011, we terminated certain agreements under which PVR provided marketing and gas gathering and processing services to us. We continue to sell gas to PVR for resale at PVR's Crossroads plant in East Texas. In connection with the disposition in 2010, we and PVG entered into transition service agreements attributable primarily to corporate and information technology functions. We billed PVG for transition services in the amount of $0.7 million, net of amounts charged to us by PVG, for the year ended December 31, 2010. This amount is included in the General and administrative caption on our Consolidated Statements of Operations as a reduction to expenses.

Supplemental Quarterly Financial Information (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2011				
Revenues	$ 68,583	$ 73,618	$ 83,353	$ 80,451
Operating loss[1]	$(28,529)	$(80,713)	$ (9,031)	$(37,146)
Loss attributable to Penn Virginia Corp.	$(26,340)	$(71,918)	$ (6,718)	$(27,939)
Loss per share – Basic[2]:	$ (0.58)	$ (1.57)	$ (0.15)	$ (0.61)
Loss per share – Diluted[2]:	$ (0.58)	$ (1.57)	$ (0.15)	$ (0.61)
Weighted-average shares outstanding:				
Basic	45,687	45,768	45,817	45,864
Diluted	45,687	45,768	45,817	45,864
2010				
Revenues	$ 67,878	$ 53,288	$ 68,953	$ 64,319
Operating income (loss)[3]	$ 92	$(20,878)	$(53,053)	$(24,969)
Net loss from continuing operations	$ 10,766	$(21,097)	$(30,159)	$(24,837)
Income (loss) from discontinued operations, net of tax	$ 12,174	$ 21,308	$ —	$ (34)
Gain on sale of discontinued operations, net of tax	$ —	$ 49,612	$ —	$ 1,934
Income (loss) attributable to Penn Virginia Corp.	$ 13,594	$ 31,079	$(30,159)	$(22,937)
Earnings (loss) per share – Basic[2]:				
Continuing operations	$ 0.24	$ (0.46)	$ (0.66)	$ (0.54)
Discontinued operations	$ 0.06	$ 0.06	$ —	$ —
Gain on sale of discontinued operations	$ —	$ 1.08	$ —	$ 0.04
Net income (loss)	$ 0.30	$ 0.68	$ (0.66)	$ (0.50)
Earnings (loss) per share – Diluted[2]:				
Continuing operations	$ 0.24	$ (0.46)	$ (0.66)	$ (0.54)
Discontinued operations	$ 0.06	$ 0.06	$ —	$ —
Gain on sale of discontinued operations	$ —	$ 1.08	$ —	$ 0.04
Net income (loss)	$ 0.30	$ 0.68	$ (0.66)	$ (0.50)
Weighted-average shares outstanding:				
Basic	45,465	45,539	45,591	45,615
Diluted	45,761	45,790	45,591	45,615

(1) Includes impairment of oil and gas properties of $71 million and $34 million during the quarters ended June 30, 2011 and December 31, 2011, respectively.

(2) The sum of the quarters may not equal the total of the respective year's earnings per common share due to changes in weighted-average shares outstanding throughout the year.

(3) Includes an impairment of $1.1 million for oil and gas properties held for sale during the quarter ended June 30, 2010. Includes impairments of oil and gas assets of $35.1 million and $9.7 million for the quarters ended September 30, 2010 and December 31, 2010, respectively.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following supplemental information regarding the oil and gas producing activities is presented in accordance with the requirements of the current oil and gas accounting standards.

Capitalized Costs Relating to Oil and Gas Producing Activities

	As of December 31,		
	2011	2010	2009
Proved properties	$ 277,987	$ 293,486	$ 353,386
Unproved properties	120,288	171,303	73,067
Wells, equipment and facilities	2,081,103	1,840,154	1,527,749
Support equipment	6,645	6,254	5,938
	2,486,023	2,311,197	1,960,140
Accumulated depreciation and depletion	(710,948)	(609,380)	(487,106)
Net capitalized costs	$1,775,075	$1,701,817	$1,473,034

ARO assets of $0.2 million, $0.1 million and $0.4 million were added to the cost basis of proved properties during the years ended December 31, 2011, 2010 and 2009, respectively.

Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
	2011	2010	2009
Proved property acquisition costs	$ —	$ 5,671	$ —
Unproved property acquisition costs	47,877	133,185	14,996
Exploration costs	77,460	66,886	7,179
Development costs and other	320,263	244,092	149,625
Total costs incurred	$ 445,600	$ 449,834	$ 171,800

Results of Operations for Oil and Gas Producing Activities

The following table includes results solely from the production and sale of oil and gas and non-cash charges for property impairments. It excludes corporate-related general and administrative expenses and gains or losses on property dispositions. Income tax expense (benefit) is calculated by applying statutory tax rates to revenues after deducting costs and giving effect to oil and gas-related permanent differences and tax credits.

	Year Ended December 31,		
	2011	2010	2009
Revenues	$ 300,046	$ 251,336	$ 228,659
Production expenses	65,835	63,854	72,255
Exploration expenses	78,943	49,641	57,754
Depreciation and depletion expense	160,293	130,816	150,429
Impairment of oil and gas properties	104,688	45,959	106,415
	(109,713)	(38,934)	(158,194)
Income tax expense (benefit)	(42,788)	(15,184)	(61,221)
Results of operations	$ (66,925)	$ (23,750)	$ (96,973)

A combined total of depletion and accretion expense related to AROs of $0.7 million was recognized in DD&A expense during each of the years ended December 31, 2011, 2010 and 2009.

Oil and Gas Reserves

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil

Supplemental Information on Oil and Gas Producing Activities (Unaudited) – (continued)

and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas sales prices may all differ from those assumed. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available.

Our Manager of Engineering is primarily responsible for overseeing the preparation of the Company's reserve estimate by our independent third party engineers, Wright & Company, Inc. The Manager of Engineering has over 26 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the state of Texas as a Professional Engineer. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

The technical person primarily responsible for review of our reserve estimates at Wright & Company, Inc., meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Wright & Company, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petro physicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

Supplemental Information on Oil and Gas Producing Activities (Unaudited) – (continued)

The following table sets forth the Company's net quantities of proved reserves, including changes therein and proved developed and proved undeveloped reserves for the periods presented. This information includes our royalty and net working interest share of the reserves in oil and gas properties. All reserves are located in the United States. Net proved oil and gas reserves for the three years ended December 31, 2011 were estimated by Wright & Company, Inc., utilizing data compiled by us.

Proved Developed and Undeveloped Reserves	Natural Gas (MMcf)	Oil and Condensate (MBbl)	Total Equivalents (MMcfe)
December 31, 2008	754,132	26,974	915,975
Revisions of previous estimates(1)	(110,349)	(8,442)	(160,995)
Extensions, discoveries and other additions(2)	180,448	9,203	235,666
Production	(43,337)	(1,277)	(51,000)
Purchase of reserves	—	—	—
Sale of reserves in place	(4,229)	(71)	(4,659)
December 31, 2009	776,665	26,387	934,987
Revisions of previous estimates(3)	(71,421)	5,202	(40,210)
Extensions, discoveries and other additions(4)	90,439	4,069	114,851
Production	(38,919)	(1,380)	(47,201)
Purchase of reserves	3,288	9	3,342
Sale of reserves in place	(15,070)	(1,490)	(24,014)
December 31, 2010	744,982	32,797	941,755
Revisions of previous estimates(5)	(61,165)	(5,414)	(93,649)
Extensions, discoveries and other additions(6)	56,345	10,399	118,746
Production	(33,410)	(2,190)	(46,553)
Purchase of reserves	1	20	124
Sale of reserves in place	(36,840)	(42)	(37,092)
December 31, 2011	669,913	35,570	883,331
Proved Developed Reserves:			
December 31, 2009	388,382	8,357	438,524
December 31, 2010	412,644	14,813	501,521
December 31, 2011	330,552	16,470	429,370
Proved Undeveloped Reserves:			
December 31, 2009	388,283	18,030	496,463
December 31, 2010	332,338	17,984	440,234
December 31, 2011	339,361	19,100	453,961

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(1) We had downward revisions of 161 Bcfe which were primarily the result of the following: 1) downward revisions of 63.1 Bcfe due to price, 2) a downward revision of 27.1 Bcfe in Appalachia for the removal of proved undeveloped reserves, which resulted from wells that no longer met the reasonable certainty threshold, 3) downward revisions of 20.1 Bcfe for NGLs that we received in East Texas as a result of lower plant yields and 4) various downward revisions amounting to 50.7 Bcfe across our assets as a result of well performance and the application of the revised oil and gas reserve calculation methodology required by the SEC in 2009.

(2) We added 235.7 Bcfe due to the drilling of 13 wells on locations that were not classified as proved undeveloped locations in our 2008 year-end reserve report and the addition of 105 new proved undeveloped locations, primarily in the Gulf Coast and Mid-Continent regions, as a result of our 2009 drilling activities.

Supplemental Information on Oil and Gas Producing Activities (Unaudited) – (continued)

(3) We had downward revisions of 40.2 Bcfe primarily as a result of the following: 1) downward revisions of 45 Bcfe due to the removal of 200 proved undeveloped locations that would not be developed within five years, 2) upward revisions of 34 Bcfe as a result of processing the gas in the Mid-Continent Granite Wash for NGLs, 3) upward revisions of 12 Bcfe due to higher prices and 4) various downward revisions for 39 Bcfe across our assets as a result of well performance, lease expirations and interest changes.

(4) We added 114.9 Bcfe due to the drilling of 16 wells on locations not classified as proved undeveloped locations in our 2009 year-end reserve report and the addition of 51 new proved undeveloped locations, primarily in East Texas, as a result of our 2010 drilling activities.

(5) We had downward revisions of 93.6 Bcfe primarily as a result of the following: 1) downward revisions of 72 Bcfe due to well performance issues, interest changes and economic limits attributable to operating conditions particularly in the Granite Wash, Cotton Valley and Selma Chalk, 2) downward revisions of 10 Bcfe due to lower condensate yield in the Granite Wash, 3) downward revisions of 9 Bcfe attributable to the elimination of proved undeveloped locations particularly in the Haynesville Shale in East Texas, 4) downward revisions of 5 Bcfe due to lower natural gas prices and 5) upward revisions of 3 Bcfe due to higher gas processing yields in the Haynesville Shale and Granite Wash.

(6) We added 118.7 Bcfe due primarily to an increase of 54 Bcfe due to the drilling of three Marcellus Shale wells and two Granite Wash wells as well as the addition of 25 proved undeveloped locations in the Marcellus Shale and Selma Chalk. We also drilled 28 Eagle Ford Shale wells and added 26 proved undeveloped locations which resulted in an increase of 65 Bcfe.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves. Future cash inflows were computed by applying the average prices of oil and gas during the 12-month period prior to the period end determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated costs as of that fiscal year end to the estimated future production of proved reserves. Natural gas prices were escalated only where existing contracts contained fixed and determinable escalation clauses. Contractually provided natural gas prices in excess of estimated market clearing prices were used in computing the future cash inflows only if we expect to continue to receive higher prices under legally enforceable contract terms. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available net operating loss carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

	Year Ended December 31,		
	2011	2010	2009
Future cash inflows	$ 5,032,915	$ 4,833,030	$ 4,178,449
Future production costs	(1,374,658)	(1,388,857)	(1,300,235)
Future development costs	(1,091,100)	(879,193)	(888,493)
Future net cash flows before income tax	2,567,157	2,564,980	1,989,721
Future income tax expense	(665,751)	(687,928)	(491,832)
Future net cash flows	1,901,406	1,877,052	1,497,889
10% annual discount for estimated timing of cash flows	(1,246,910)	(1,235,633)	(973,118)
Standardized measure of discounted future net cash flows	$ 654,496	$ 641,419	$ 524,771

Supplemental Information on Oil and Gas Producing Activities (Unaudited) – (continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Year Ended December 31,		
	2011	2010	2009
Sales of oil and gas, net of production costs	$(234,211)	$(180,568)	$(157,891)
Net changes in prices and production costs	(25,398)	180,316	(314,209)
Extensions, discoveries and other additions	361,284	59,729	138,482
Development costs incurred during the period	44,741	153,563	65,043
Revisions of previous quantity estimates	(113,188)	(50,471)	(158,844)
Purchases of reserves-in-place	308	2,239	—
Sale of reserves-in-place	(37,474)	(47,740)	—
Accretion of discount	87,815	68,817	90,796
Net change in income taxes	16,818	(73,332)	15,168
Other changes	(87,618)	4,095	116,825
Net increase (decrease)	13,077	116,648	(204,630)
Beginning of year	641,419	524,771	729,401
End of year	$ 654,496	$ 641,419	$ 524,771

The standardized measure of discounted future net cash flows is not intended, and should not be interpreted, to represent the fair value of our oil and gas reserves. An estimate of the fair value would also consider, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and cost, and a discount factor more representative of economic conditions and risks inherent in reserve estimates. Accordingly, the changes in standardized measure reflected above do not necessarily represent the economic reality of such transactions. See ‘‘Costs Incurred in Certain Oil and Gas Activities’’ earlier in this Note and our Consolidated Statements of Cash Flows.

Item 9 *Changes in and Disagreements With Accountants on Accounting and Financial Disclosure*

None.

Item 9A *Controls and Procedures*

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2011. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported accurately and on a timely basis. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2011, such disclosure controls and procedures were effective.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. This evaluation was completed based on the framework established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our management has concluded that, as of December 31, 2011, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

KPMG LLP, an independent registered public accounting firm, has issued an attestation report on the internal control over financial reporting as of December 31, 2011, which is included in Item 8 of this Annual Report on Form 10-K.

(d) Changes in Internal Control Over Financial Reporting

No changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B *Other Information*

There was no information that was required to be disclosed by us on a Current Report on Form 8-K during the fourth quarter of 2011 which we did not disclose.

Part III

Item 10 ***Directors, Executive Officers and Corporate Governance***

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11 ***Executive Compensation***

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 12 ***Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters***

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14 ***Principal Accountant Fees and Services***

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Part IV

Item 15 ***Exhibit and Financial Statement Schedules***

The following documents are filed as exhibits to this Annual Report on Form 10-K:

(1) Financial Statements — The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 56 of this Annual Report on Form 10-K.

(2.1) Purchase and Sale Agreement dated July 28, 2011, by and among Penn Virginia MC Energy L.L.C., Penn Virginia Oil & Gas Corporation and Unit Petroleum Company, as amended by Amendment and Supplement to Purchase and Sale Agreement dated August 31, 2011 (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on September 7, 2011).

(3.1) Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(3.1.1) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(3.1.2) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).

(3.1.3) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on June 12, 2007).

(3.1.4) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on May 10, 2010).

(3.2) Amended and Restated Bylaws of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on February 18, 2011).

(4.1) Subordinated Indenture dated December 5, 2007 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(4.1.1) First Supplemental Indenture relating to the 4.50% Convertible Senior Subordinated Notes due 2012, dated December 5, 2007 between Penn Virginia Corporation, as Issuer, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(4.1.2) Form of Note for 4.50% Convertible Senior Subordinated Notes due 2012 (incorporated by reference to Exhibit A to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(4.2) Senior Indenture dated June 15, 2009 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 16, 2009).

(4.2.1) First Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated June 15, 2009 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).

(4.2.2)	Second Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated April 4, 2011 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 5, 2011).
(4.2.3)	Form of Note for 10.375% Senior Notes due 2016 (incorporated by reference to Annex A to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).
(4.2.4)	Third Supplemental Indenture relating to the 7.25% Senior Notes due 2019, dated April 13, 2011, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 14, 2011).
(4.2.5)	Form of Note for 7.25% Senior Notes due 2019 (incorporated by reference to Exhibit 4.3 to Registrant's Current Report on Form 8-K filed on April 14, 2011).
(10.1)	Amended and Restated Credit Agreement dated as of August 2, 2011 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on August 4, 2011).
(10.1.2)	First Amendment to Amended and Restated Credit Agreement dated January 11, 2012 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on January 17, 2012).
(10.2)	Contribution Agreement dated June 7, 2010 by and among Penn Virginia Resource GP Corp., Penn Virginia GP Holdings, L.P. and PVG GP, LLC (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 7, 2010).
(10.4)	Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.4.1)	Amendment 2009-1 to the Penn Virginia Corporation Supplemental Employee Retirement Plan.*
(10.5)	Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.5.1)	Amendment One to the Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 6, 2011).*
(10.6)	Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.29 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.6.1)	Form of Agreement for Deferred Common Stock Unit Grants under the Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.30 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.7)	Penn Virginia Corporation Seventh Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on August 2, 2010).*

(10.7.1) Amendment No. 1 to the Penn Virginia Corporation Seventh Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on May 6, 2011).*

(10.7.2) Form of Agreement for Stock Option Grants under the Penn Virginia Corporation Seventh Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*

(10.7.3) Form of Agreement for Restricted Stock Awards under the Penn Virginia Corporation Seventh Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.33 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*

(10.7.4) Form of Agreement for Restricted Stock Unit Awards under the Penn Virginia Corporation Seventh Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on February 23, 2009).*

(10.8) Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*

(10.9) Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*

(10.10) Executive Change of Control Severance Agreement dated December 8, 2010 between Penn Virginia Corporation and Steven A. Hartman (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 10, 2010).*

(10.11) Executive Change of Control Severance Agreement dated October 26, 2011 between Penn Virginia Corporation and John A. Brooks.*

(10.12) Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and Michael E. Stamper.*

(10.13) Amended and Restated Change of Location Severance Agreement dated March 30, 2010 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 31, 2010).*

(10.14) Penn Virginia Corporation 2011 Annual Incentive Cash Bonus and Long-Term Equity Compensation Guidelines (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 1, 2011).*

(12.1) Statement of Computation of Ratio of Earnings to Fixed Charges Calculation.

(14.1) Penn Virginia Corporation Code of Business Conduct and Ethics (incorporated by reference to Exhibit 14.1 to Registrant's Current Report on Form 8-K filed on July 27, 2009).

(21.1) Subsidiaries of Penn Virginia Corporation.

(23.1) Consent of KPMG LLP.

(23.2) Consent of Wright & Company, Inc.

(31.1) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(31.2) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(32.1) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(32.2) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(99.1) Report of Wright & Company, Inc. dated January 20, 2012 concerning evaluation of oil and gas reserves.

(101.INS) XBRL Instance Document

(101.SCH) XBRL Taxonomy Extension Schema Document

(101.CAL) XBRL Taxonomy Extension Calculation Linkbase Document

(101.DEF) XBRL Taxonomy Extension Definition Linkbase Document

(101.LAB) XBRL Taxonomy Extension Label Linkbase Document

(101.PRE) XBRL Taxonomy Extension Presentation Linkbase Document

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* Management contract or compensatory plan or arrangement.

SIGNATURES

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

PENN VIRGINIA CORPORATION

February 27, 2012	By:	/s/ STEVEN A. HARTMAN **Steven A. Hartman** **Senior Vice President and Chief Financial Officer**
February 27, 2012	By:	/s/ JOAN C. SONNEN **Joan C. Sonnen** **Vice President and Controller**

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

/s/ EDWARD B. CLOUES, II **Edward B. Cloues, II**	Chairman of the Board and Director	February 27, 2012
/s/ JOHN U. CLARKE **John U. Clarke**	Director	February 27, 2012
/s/ ROBERT GARRETT **Robert Garrett**	Director	February 27, 2012
/s/ STEVEN W. KRABLIN **Steven W. Krablin**	Director	February 27, 2012
/s/ MARSHA R. PERELMAN **Marsha R. Perelman**	Director	February 27, 2012
/s/ PHILIPPE VAN MARCKE DE LUMMEN **Philippe van Marcke de Lummen**	Director	February 27, 2012
/s/ H. BAIRD WHITEHEAD **H. Baird Whitehead**	Director and President and Chief Executive Officer	February 27, 2012
/s/ GARY K. WRIGHT **Gary K. Wright**	Director	February 27, 2012

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