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, 2012

Commission file number: 1-13283

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 $333,361,639 as of June 30, 2012 (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 19, 2013, 55,117,346 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 1, 2013, 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, 2012

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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 the 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 oil, natural gas liquids and natural gas;
- our ability to develop, explore for, acquire and replace oil and natural 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 oil, natural gas liquids and natural gas;
- reductions in the borrowing base under our revolving credit facility;
- 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 regulations 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, 2012.

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.
MBOE	One thousand barrels of oil equivalent.
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.
MMBOE	One million barrels of oil equivalent.
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 well or 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.

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 oil, NGLs and natural gas in various domestic onshore regions of the United States, including Texas, the Mid-Continent and Mississippi. We operate in and report our financial results and disclosures as one segment. Each of our operating regions has similar economic characteristics and meets the criteria for aggregation.

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.

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. Accordingly, PVG's results of operations, financial position and cash flows have been reported as discontinued operations for all applicable periods included herein.

Description of Business

Business Overview

As of December 31, 2012, our proved reserves were approximately 113 MMBOE, of which 41 percent were proved developed reserves and 40 percent were oil and NGLs. Our proved reserves and primary development plays are located in Texas, the Mid-Continent and Mississippi, which comprised 73 percent, 11 percent and 16 percent of our total proved reserves, respectively, as of December 31, 2012. In 2012, our production totaled 6.5 MMBOE. Texas, the Mid-Continent, Mississippi and Appalachia comprised 56 percent, 19 percent, 13 percent and 12 percent of total production volumes, respectively, during 2012. In the three years ended December 31, 2012, we drilled 166 gross (117.0 net) wells, of which 96 percent were productive.

As of December 31, 2012, we had 1,103 gross (910.8 net) productive wells, approximately 97 percent of which we operate, and owned approximately 0.3 million gross (0.2 million net) acres of leasehold and royalty interests, approximately 53 percent of which were undeveloped. Our proved undeveloped locations and additional potential drilling locations are direct offsets or extensions from existing production. We believe we have multiple years of drilling opportunities on our existing undeveloped acreage based on our historical drilling rate. For a more detailed discussion of our reserves, production, wells and acreage, see Item 2, “Properties.”

In 2012, our capital expenditures were approximately $385 million, of which approximately $287 million, or 74 percent, was related to development drilling, approximately $49 million, or 13 percent, was related to exploratory drilling and approximately $28 million, or seven percent, was related to leasehold acquisitions. The remaining $21 million, or six percent, was related to pipelines, gathering assets, facilities and corporate projects.

The past two years have been transformational for us as we have diversified our portfolio towards primarily oil and NGL investment opportunities. During 2012, we grew our oil and NGL production to 48 percent (56 percent for the 4th quarter of 2012) of our total production, an increase of approximately 43 percent over 2011, and we invested approximately $376 million in oil- and NGL-related capital projects. 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. We have been very active in the Eagle Ford Shale play in South Texas, which provided approximately 36 percent of our 2012 production. In addition, we invested approximately $350 million, or 91 percent, of our 2012 capital program to projects in this play. We believe our project inventory in the Eagle Ford Shale provides us opportunities for continued oil- and NGL-focused investments over the next several years. Our current operations consist primarily of drilling unconventional horizontal development wells in shale formations.

In 2012, we sold our legacy natural gas assets in West Virginia, Kentucky and Virginia which comprised a significant portion of our operations in Appalachia. We have retained producing wells and significant undeveloped acreage in the Marcellus Shale area of the Appalachian region. For additional information on this disposition, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Developments."

Business Strategy

We intend to pursue the following business strategies:

- *Continue to expand oil and NGL reserves and drilling inventory*. We anticipate spending up to approximately $400 million for capital expenditures in 2013. We plan to allocate up to $345 million, or approximately 86 percent, to drilling and completion projects, primarily on our Eagle Ford Shale acreage in Gonzales and Lavaca Counties in South Texas. We plan to allocate up to $30 million, or approximately eight percent, to leasehold projects to further expand our drilling inventory. We anticipate allocating the remaining $25 million, or approximately six percent, to pipeline, gathering, seismic and and facilities projects.
- *Grow our cash flows and margins.* We expect our operating cash flows and margins will continue to grow on a pro forma basis taking into consideration recent asset sales as we increase our oil and NGL production through investment in higher rate-of-return development oil projects.
- *Maintain our liquidity and financial position.* We expect to continue to use our operating cash flows and borrowings under our revolving credit facility, or the Revolver, to fund our capital requirements in 2013. The Revolver limits our leverage to 4.5 times EBITDAX (as defined in the Revolver) through December 31, 2013, 4.25 times EBITDAX through June 30, 2014 and 4.0 times EBITDAX thereafter through its maturity in 2017. We have no material debt maturities until 2016.
- *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, which are largely held by production. At this time, we plan to retain these assets, which provide us with the option to increase development in these regions when natural gas prices improve.
- *Pursue selective divestitures of non-core assets to increase margins, operational focus and liquidity.* From time to time, we may dispose of certain non-core assets and reinvest the proceeds into our oil- and NGL-focused projects.
- *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 flows at risk, available hedge prices and our operating strategy. For 2013, we have hedged approximately 58 percent of our estimated crude oil production at average floor/swap and ceiling prices of $97.35 and $100.99 per barrel. In addition, we have hedged approximately 55 percent of our estimated natural gas production at a weighted-average floor/swap price of $3.76 per MMBtu and ceiling price of $4.19 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 crude oil, NGL and natural gas products using short-term floating price physical and spot market contracts. For the year ended December 31, 2012, approximately 59 percent of our consolidated product revenues were attributable to four customers: Sunoco Refining and Marketing, Inc.; Shell Trading (US) Company; Gulfmark Energy Inc.; and Enterprise Crude Oil LLC.

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 the 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 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 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, 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. The 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 Fracturing Responsibility and Awareness of Chemicals Act that was introduced in both the 111^{th} and 112^{th} Congresses would subject hydraulic fracturing operations to federal regulation under the SDWA and require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. Sponsors of these bills 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 impacts of hydraulic fracturing on drinking water and ground water. The EPA released a progress report on its study on December 21, 2012 and expects to release a final draft for public comment and peer review in 2014.

Additionally, certain states in which we operate have adopted regulations requiring the disclosure of chemicals used in the hydraulic fracturing process. For instance, Mississippi, Oklahoma, Pennsylvania and Texas 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.

Prohibitions and Other Regulatory Limitations on Hydraulic Fracturing. There have been a variety of regulatory initiatives at the state level to restrict oil and gas drilling operations in certain locations. For example, Pennsylvania has instituted a moratorium on leasing state forest land for gas drilling and municipalities in New York have banned or limited hydraulic fracturing within their borders. 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. The most recent draft of the SGEIS was released in September 2011 but final regulations have not yet been issued.

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. Pennsylvania and West Virginia have issued setback regulations for wells. Colorado recently enacted new setback restrictions as well as requirements to conduct sampling on water wells before and after drilling. In addition, states such as Texas and Pennsylvania have water withdrawal restrictions allowing suspension of withdrawal rights in times of shortages while other states require reporting on the amount of water used and its source.

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. 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.

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 April 17, 2012, the EPA issued new rules subjecting 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 new rules 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 apply to newly drilled and fractured wells, as well as existing wells that are refractured. The NESHAPS regulations apply to certain major sources of hazardous air pollutants not previously subject to Maximum Achievable Control Technology, or MACT, standards. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our compressors at initial startup, or October 15, 2012, whichever is later. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. We are currently researching the effect these new rules will 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. If we were required to aggregate individual wells and other facilities, it could bring us within the ambit of the Title V permitting program, and we could be considered a major source for MACT applicability. For example, though the Sixth Circuit recently vacated an EPA determination to aggregate natural gas wells and a sweetening plant in *Summit Petroleum Corp. v. EPA et al.*, the EPA released a December 21, 2012 memorandum stating that although the EPA will follow the court's interpretation when considering aggregation in the Sixth Circuit, it will continue to follow its current practice of considering interrelatedness in other jurisdictions. In addition, in *Citizens for Pennsylvania's Future v. Ultra Resources, Inc.*, a case challenging a decision not to aggregate certain facilities in Pennsylvania, the court allowed the case to move forward by denying defendant's motion to dismiss, even though the plaintiff had not exhausted review procedures with the administrative agency.

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 GHGs per year to collect and report to the EPA data regarding such emissions. The Reporting Rule establishes a new comprehensive scheme, which began 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 were subject to judicial challenge, but on June 26, 2012, the U.S. Court of Appeals for the District of Columbia Circuit rejected challenges to the tailoring rule and other EPA rules relating to the regulation of GHGs under the CAA.

Starting July 1, 2011, the EPA required 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. On March 27, 2012, the EPA issued its proposed NSPS for carbon dioxide emissions standard from new and modified power plants and held public hearings on the rule in May 2012 and accepted written comments until June 25, 2012. The U.S. Congress has considered a number of legislative proposals to restrict GHG emissions. 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. While it is not possible to predict how any regulations to restrict GHG emissions may come into force, these and other legislative and regulatory proposals for restricting GHG emissions or otherwise addressing climate change could require us to incur additional operating costs or curtail oil and gas operations in certain areas and could also adversely affect demand for the oil and natural gas we sell.

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 had a total of 130 employees as of December 31, 2012. 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.

Crude oil, NGL and natural gas 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 crude oil, NGLs and natural gas. Historically, crude oil, NGL and natural gas prices have been volatile, and they are likely to continue to be volatile. Even relatively modest drops in prices can affect significantly our financial results and impede our growth. Wide fluctuations in crude oil, NGLs and natural gas prices may result from relatively minor changes in the supply of and demand for oil and natural gas, market demand and other factors that are beyond our control, including:

- domestic and foreign supplies of crude oil, NGLs and natural gas;
- domestic and foreign consumer demand for oil and natural gas;
- 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 gathering, processing and transportation facilities;
- weather conditions; and
- domestic and foreign governmental regulation.

Many of our projections and estimates are based on assumptions as to the future prices of crude oil, NGLs and natural gas. 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 crude oil, NGLs or natural gas 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 oil and natural gas 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 natural 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 and production from such activities at acceptable costs. Currently depressed gas prices may further limit the types of reserves that can be developed economically. 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 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 2013, we anticipate making capital expenditures, excluding acquisitions, of up to approximately $400 million.

If crude oil or NGL prices decrease, natural 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 our capital expenditures unless we have borrowing capacity under the Revolver.

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 crude oil, NGLs and natural gas.

If our revenues were to decrease due to lower crude oil, NGL and natural 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.

We have a significant amount of indebtedness and our ability to service our indebtedness depends on certain financial, business and other factors, many of which are beyond our control.

At December 31, 2012, we had an aggregate of approximately $600 million of debt outstanding and would have been able to incur an additional $297.9 million (net of $2.1 million of letters of credit) under the Revolver. We may incur additional indebtedness in the future. Subject to certain conditions, our existing debt instruments do not prohibit us from incurring additional indebtedness. Any increase in our level of indebtedness will have several important effects on our future operations, including, without limitation:

- we will have additional cash requirements in order to support the payment of interest on our outstanding indebtedness;
- increases in our outstanding indebtedness and leverage will increase our vulnerability to adverse changes in general economic and industry conditions, as well as to competitive pressure; and
- depending on the levels of our outstanding debt, our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes may be limited.

Our ability to make scheduled payments of principal and interest on our indebtedness or to refinance our debt obligations depends on our future financial condition and operating performance, which will be subject to general economic conditions and to certain financial, business and other factors affecting our operations, many of which are beyond our control. If we are unable to generate sufficient cash flows from operations in the future to service our debt, we may be forced, among other things, to:

- seek additional financing in the debt or equity markets;
- refinance or restructure all or a portion of our indebtedness;
- sell selected assets;
- reduce or delay planned capital expenditures; or
- reduce or delay planned operating expenditures.

Such measures might not be successful and might not enable us to service our debt. In addition, any such financing, refinancing or sale of assets might not be available on economically favorable terms.

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

The borrowing base under the Revolver is $300 million as of December 31, 2012. Our borrowing base is re-determined twice a year and is scheduled to be redetermined during April 2013. If crude oil, NGL or natural gas prices decline, the borrowing base under the Revolver may be reduced. As a result, we may be unable to obtain funding under the 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.

The Revolver and our other debt instruments have restrictive covenants that could limit our financial flexibility.

The Revolver and the indentures related to our outstanding senior notes contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Revolver is subject to compliance with certain financial covenants, including leverage and interest coverage ratios. The Revolver includes other restrictions that, among other things, limit our ability to incur indebtedness; grant liens; engage in mergers, consolidations and liquidations; make asset dispositions, restricted payments and investments; enter into transactions with affiliates; and amend, modify or prepay certain indebtedness. The indentures related to our outstanding senior notes contain limitations on our ability to effect mergers and change of control events, as well as other limitations, including:

- limitations on the declaration and payment of dividends or other restricted payments;
- limitations on incurring additional indebtedness or issuing preferred stock;
- limitations on the creation or existence of certain liens;
- limitations on incurring restrictions on the ability of certain of our subsidiaries to pay dividends or other payments;
- limitations on transactions with affiliates; and
- limitations on the sale of assets.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our debts. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

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 oil or natural gas 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;
- elevated pressure or irregularities in geologic formations;
- equipment failures or accidents;
- costs, shortages or delays in the availability of drilling rigs, crews, 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;
- fires, explosions, blow-outs and surface cratering; and
- adverse weather conditions.

The prevailing prices of crude oil, NGLs and natural 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 oil or natural gas 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 effect on our ability to develop and produce oil and natural 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 nonpayment or nonperformance by these parties would reduce our cash flows.

We are subject to risk from loss resulting from our customers' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of revenues. In 2012, 59 percent of our total consolidated product revenues resulted from four of our customers. Any nonpayment or nonperformance by our customers would reduce our cash flows.

We participate in oil and gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one party. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. In addition, the possibility of an economic downturn and the volatility in commodity prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established than we, are not able to fulfill their joint activity obligations. Some of our project partners have experienced liquidity and cash flow problems. These problems may lead our partners to attempt to delay the pace of drilling or project development in order to preserve cash. A partner may be unable or unwilling to pay its share of project costs. In some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial condition and results of operations.

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 oil or natural gas 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 shut down, 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; or
- 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 or that we can purchase insurance against all possible 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 gathering, processing and 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 of 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, process 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 natural 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 crude oil, NGL 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, crude oil, NGL and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural 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 crude oil, NGL and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2012, approximately 59 percent 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.

Moreover, the reserve estimation standards provide that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These standards may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not develop those reserves within the required five-year time frame or cannot demonstrate that we could do so. We removed approximately 8.7 MMBOE of proved undeveloped reserves in 2012 as a result of the five-year limitation.

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 natural 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 crude oil, NGL and natural 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 and other factors. During the past several years, we have been required to impair certain of our oil and gas properties and related assets. If crude oil, NGL and natural gas 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 2012, other companies operated approximately 17 percent 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.

Our property acquisitions carry significant risks.

Acquisition of 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 crude oil, NGL and natural 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 natural 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 natural 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 all of our wells. The EPA has commenced a study of the potential environmental impact of hydraulic fracturing. 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. In addition, some states and local governments have enacted legislation or adopted regulations, and the U.S. Congress and other states are considering enacting legislation or 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, prohibited or subjected to further regulation, these requirements 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.

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 crude oil, NGLs and natural gas, we periodically enter into commodity 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 crude oil, NGL and natural gas prices, such transactions may limit our potential gains if crude oil, NGL 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 crude oil, NGL 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 crude oil, NGL 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.

The enactment of derivatives legislation and regulation 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.

On July 21, 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act, was enacted that establishes federal oversight regulation of over-the-counter derivatives market and entities, such as us, that participate in that market. The Act requires the Commodities Futures Trading Commission, or CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. 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 would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Columbia in September 2012, although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of “swap,” “security-based swap,” “swap dealer” and “major swap participant.” The Act and CFTC rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements, although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Act and CFTC rules on us or the timing of such effects. The Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Act and associated regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and 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 Act and associated 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 Act 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 Act is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Our ability to use net operating loss carryforwards to offset future taxable income may be subject to certain limitations.

Our ability to utilize U.S. net operating loss. or NOL, carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended, or the Code. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of our stock by 5% shareholders and our offering of stock during any three-year period resulting in an aggregate change of more than 50% in our beneficial ownership. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these carryforwards. As of December 31, 2012, we do not believe that an ownership change has occurred; however, to the extent an ownership change has occurred or were to occur in the future, it is possible that the limitations imposed on our ability to use pre-ownership change losses could cause a significant net increase in our U.S. federal income tax liability and could cause U.S. federal income taxes to be paid earlier than they otherwise would be paid if such limitations were not in effect.

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.

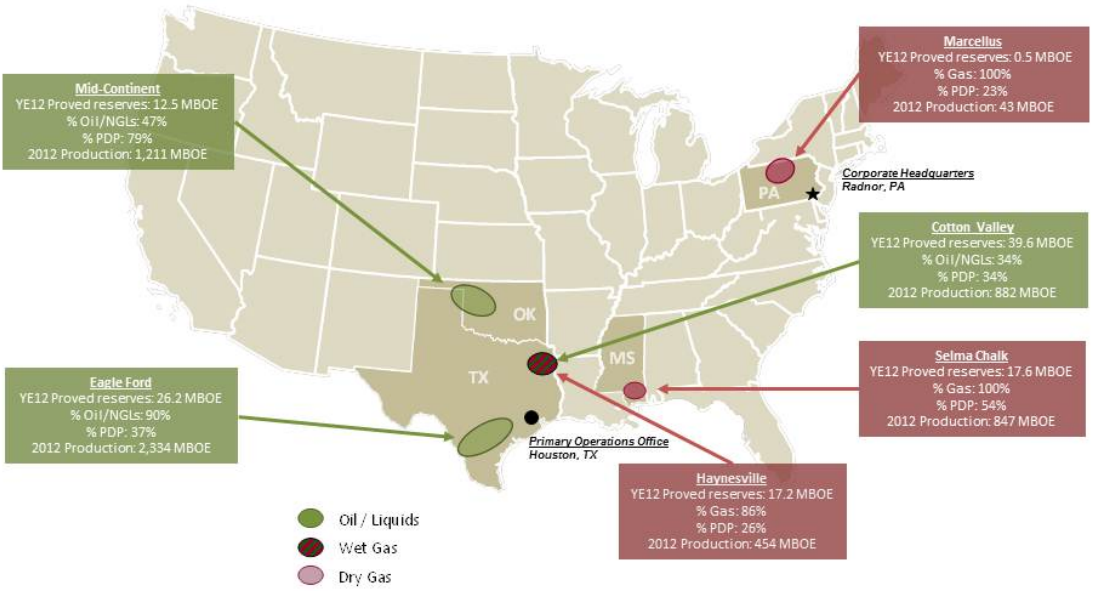
President Obama's budget proposal for fiscal year 2013 recommended the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, the repeal of the percentage depletion allowance for oil and natural gas properties, the elimination of current deductions for intangible drilling and development costs, the elimination of the deduction for United States production activities for oil and gas production, 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 that were issued 180 days or more preceding the end of our 2012 fiscal year and remain unresolved.

Item 2 ***Properties***

The following map shows the general locations of our oil and gas production investments as of December 31, 2012:



Facilities

Our headquarters and corporate office is located in Radnor, Pennsylvania and our primary operations are conducted from our office in Houston, Texas. We also have district operations facilities at various locations in Texas, Oklahoma and Mississippi. All of our office facilities are leased with the exception of our district operations facilities in Scottsville, Texas. 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 when we 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 are structured to objectively and accurately estimate our oil and gas reserve 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 27 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. Our 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, 2012, 2011 and 2010. 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 natural 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, 2012 with any federal authority or agency with respect to our estimate of oil and natural gas reserves.

	Oil	NGLs	Natural Gas	Oil Equivalents	Standardized Measure	Price Measurement Used [1]		
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	$ in millions	$/Bbl of Oil	$/Bbl of NGLs	$/MMBtu
2012								
Developed	10.5	8.3	169	47.0	$ 452			
Undeveloped	14.4	12.4	238	66.5	46			
	24.9	20.7	407	113.5	$ 498	$ 102.24	$ 39.48	$ 2.47
2011								
Developed	7.1	9.4	331	71.6	$ 602			
Undeveloped	7.0	12.1	339	75.6	52			
	14.1	21.5	670	147.2	$ 654	$ 92.22	$ 50.69	$ 3.95
2010								
Developed	4.0	10.8	413	83.6	$ 574			
Undeveloped	4.0	14.0	332	73.4	67			
	8.0	24.8	745	157.0	$ 641	$ 79.43	$ 41.14	$ 4.38

[1] Oil, NGL and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu 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 States. 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, 2012:

Region	Proved Reserves	% of Total Proved Reserves	% Proved Developed
	(MMBOE)		
Texas	82.9	73.0%	33.2%
Mid-Continent	12.5	11.0%	79.2%
Mississippi	17.6	15.5%	53.8%
Appalachia (Marcellus Shale)	0.5	0.5%	22.6%
	113.5	100.0%	

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, 2012:

	Oil	NGLs	Natural Gas	Oil Equivalents
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)
Proved undeveloped reserves at beginning of year	7.0	12.1	339	75.6
Revisions of previous estimates	(1.0)	(1.3)	(104)	(19.6)
Extensions, discoveries and other additions	10.6	2.2	11	14.6
Sale of reserves in place	—	—	(4)	(0.6)
Conversion to proved developed reserves	(2.2)	(0.6)	(4)	(3.5)
Proved undeveloped reserves at end of year	14.4	12.4	238	66.5

In 2012, our proved undeveloped reserves decreased by 9.1 MMBOE to 66.5 MMBOE as of December 31, 2012 from 75.6 MMBOE as of December 31, 2011. We experienced negative revisions of 19.6 MMBOE, consisting of 10.5 MMBOE due to lower natural gas pricing and 9.1 MMBOE due to locations that are not expected to be drilled during a five-year period (primarily in the Selma Chalk and Haynesville plays), non-participation and lease expirations. Extensions, discoveries and other additions of 14.6 MMBOE were attributable exclusively to our activities in the Eagle Ford Shale. We had a decrease of 0.6 MMBOE due to the sale of our properties, including proved undeveloped locations, in West Virginia, Kentucky and Virginia. In addition, we converted 3.5 MMBOE from proved undeveloped to proved developed classification, consisting of 16 wells in the Eagle Ford Shale (2.4 MMBOE) and six wells in the Granite Wash (1.1 MMBOE).

During 2012, we incurred capital expenditures of approximately $116.9 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:

Region	Average Daily Production for the Year Ended December 31, 2012	2011	2010	Total Production for the Year Ended December 31, 2012	2011	2010
		(BOEPD)			(MBOE)	
Texas	10,030	8,150	6,175	3,671	2,976	2,254
Mid-Continent [1]	3,309	5,973	7,005	1,211	2,180	2,557
Mississippi	2,314	2,993	3,490	847	1,092	1,274
Appalachia [2]	2,143	4,138	4,747	784	1,511	1,733
Gulf Coast [3]	—	—	135	—	—	49
	17,796	21,254	21,552	6,513	7,759	7,867

[1] We sold a substantial portion of our Arkoma Basin properties in August 2011, which represented annual production of approximately 700 MBOE (1,800 BOEPD).
[2] We sold all of our properties in West Virginia, Kentucky and Virginia in July 2012, which represented annual production of approximately 1,500 MBOE (4,100 BOEPD).
[3] 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, 2012	2011	2010
Average prices:			
Crude oil ($ per Bbl)	$ 101.95	$ 93.19	$ 75.56
NGLs ($ per Bbl)	$ 35.13	$ 47.83	$ 39.69
Natural gas ($ per Mcf)	$ 2.46	$ 4.10	$ 4.40
Production cost (aggregate $ per BOE)	$ 6.98	$ 6.72	$ 6.35

Significant Fields

Our Carthage field in East Texas, consisting of our Cotton Valley and Haynesville Shale properties, represents approximately 35% of our total equivalent proved reserve quantities as of December 31, 2012. Our Eagle Ford Shale play in Gonzales and Lavaca Counties in South Texas, which primarily contains oil reserves, represents approximately 23% of our total equivalent proved reserve quantities as of December 31, 2012. These are the only fields that comprise 15% or more of our total proved reserves as of that date.

The following table sets forth certain information with respect to these fields for the periods presented:

	Year Ended December 31,		
	2012	**2011**	**2010**
Carthage Field			
Production:			
Crude oil (MBbl)	68	106	106
NGLs (MBbl)	281	440	390
Natural gas (MMcf)	5,467	8,417	9,725
Average prices:			
Crude oil ($ per Bbl)	$ 96.61	$ 93.97	$ 77.89
NGLs ($ per Bbl)	$ 36.31	$ 49.82	$ 39.00
Natural gas ($ per Mcfe)	$ 2.30	$ 3.69	$ 4.13
Production cost (aggregate $ per BOE)	$ 6.24	$ 8.16	$ 6.18
Eagle Ford Shale [1]			
Production:			
Crude oil (MBbl)	1,960	751	—
NGLs (MBbl)	205	55	—
Natural gas (MMcf)	1,015	277	—
Average prices:			
Crude oil ($ per Bbl)	$ 103.33	$ 93.74	$ —
NGLs ($ per Bbl)	$ 31.43	$ 51.21	$ —
Natural gas ($ per Mcfe)	$ 2.56	$ 3.66	$ —
Production cost (aggregate $ per BOE)	$ 8.83	$ 6.26	$ —

[1] Production began in the Eagle Ford Shale in 2011.

Drilling Activities

Wells Drilled

The following table sets forth the gross and net development and exploratory wells that we drilled during the years ended December 31, 2012, 2011 and 2010 and 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.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	36	27.8	45	32.1	59	40.0
Non-productive	—	—	—	—	—	—
Under evaluation	—	—	2	1.3	—	—
Total development	36	27.8	47	33.4	59	40.0
Exploratory						
Productive	5	3.9	5	3.8	5	2.7
Non-productive	—	—	4	2.7	3	1.2
Under evaluation	1	1.0	—	—	1	0.5
Total exploratory	6	4.9	9	6.5	9	4.4
Total	42	32.7	56	39.9	68	44.4
Wells in progress at end of year	3	2.7	7	5.8	6	3.5

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

	2012		2011		2010	
Region	Gross	Net	Gross	Net	Gross	Net
Texas	35	29.5	32	26.7	12	11.1
Mid-Continent	7	3.2	19	8.9	41	18.7
Mississippi	—	—	—	—	14	13.8
Appalachia	—	—	5	4.3	1	0.8
	42	32.7	56	39.9	68	44.4

Present Activities

As of December 31, 2012, we had three gross (2.7 net) wells in progress, all of which were located in South Texas. As of February 20, 2013, two of these wells, which were Eagle Ford Shale wells, had been successfully completed and placed on production. The remaining well targeting the Pearsall Shale remains under evaluation.

Delivery Commitments

We generally sell our oil, NGL and natural gas 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, 2012, we did not have any material commitments to provide a fixed and determinable quantity of our products 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, 2012:

	Primarily Oil		Primarily Natural Gas		Total	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Texas	69	57.4	358	254.9	427	312.3
Mid-Continent	11	7.1	97	41.8	108	48.9
Mississippi	—	—	565	546.6	565	546.6
Appalachia	—	—	3	3.0	3	3.0
	80	64.5	1,023	846.3	1,103	910.8

Of the total wells presented in the table above, we are the operator of 1,007 gross (78 oil and 929 gas) and 880.5 net (63.9 oil and 816.6 gas) wells. In addition to the above working interest wells, we own royalty interests in seven gross wells.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2012 (in thousands):

	Developed		Undeveloped		Total	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Texas	68	50.3	25	17.5	93	67.8
Mid-Continent	20	10.7	83	44.6	103	55.3
Mississippi	37	27.7	3	1.9	40	29.6
Appalachia	2	1.3	46	37.0	48	38.3
	127	90.0	157	101.0	284	191.0

Our total net acreage decreased by approximately 80 percent in 2012 due to the sale of our legacy properties in West Virginia, Kentucky and Virginia. The primary terms of our remaining leases generally range from three to five years and we do not have any concessions. As of December 31, 2012, 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:

	2013	2014	2015	Thereafter
Percent of gross undeveloped acreage	56%	23%	15%	6%
Percent of net undeveloped acreage	47%	27%	17%	9%

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 acreage expiring in 2013 is located primarily in the Anadarko Basin and the Marcellus Shale, areas that are not integral to our capital program.

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 ***Mine Safety Disclosures***

Not applicable.

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 2012 and 2011 were as follows:

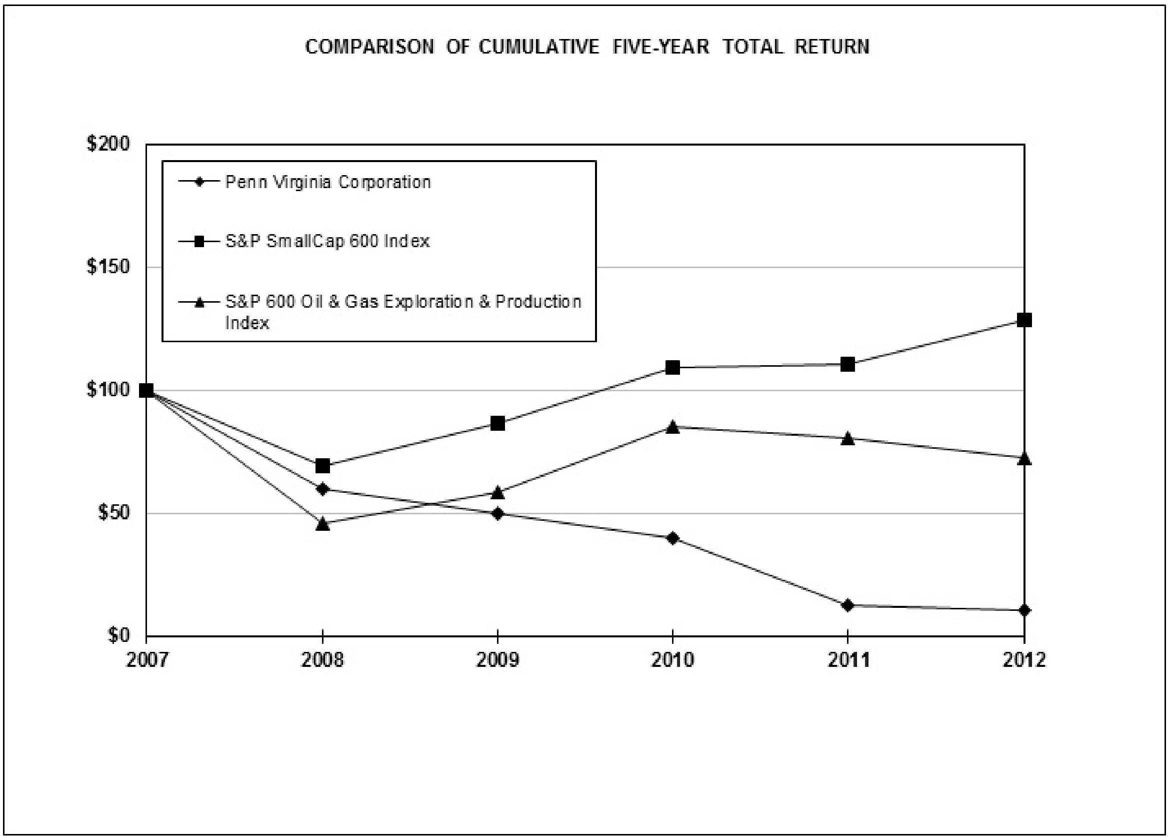
	Sales Price		Cash Dividends
Quarter Ended	**High**	**Low**	**Declared**
December 31, 2012	$ 6.72	$ 4.07	$ —
September 30, 2012	$ 7.74	$ 6.01	$ —
June 30, 2012	$ 7.37	$ 3.92	$ 0.05625
March 31, 2012	$ 6.27	$ 4.27	$ 0.05625
December 31, 2011	$ 6.97	$ 4.21	$ 0.05625
September 30, 2011	$ 14.12	$ 5.47	$ 0.05625
June 30, 2011	$ 17.20	$ 12.88	$ 0.05625
March 31, 2011	$ 18.31	$ 14.40	$ 0.05625

Equity Holders

As of February 15, 2013, there were 440 record holders and 7,216 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, 2012, there were ten companies in the Standard & Poor's 600 Oil & Gas Exploration & Production Index: Approach Resources Inc., Carrizo Oil & Gas, Inc., Comstock Resources, Inc., Contango Oil & Gas Company, Gulfport Energy Corporation, PDC Energy, Inc., Penn Virginia Corporation, PetroQuest Energy, Inc., Stone Energy Corporation and Swift Energy Company. The graph assumes $100 is invested on January 1, 2008 in us and each index at December 31, 2007 closing prices.



	December 31,				
	2008	2009	2010	2011	2012
Penn Virginia Corporation	$ 59.84	$ 49.68	$ 39.74	$ 12.81	$ 10.91
S&P Small Cap 600 Index	$ 68.93	$ 86.55	$ 109.32	$ 110.43	$ 128.46
S&P 600 Oil & Gas Exploration & Production Index	$ 46.13	$ 58.76	$ 85.44	$ 80.45	$ 72.71

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, 2012, 2011, 2010, 2009 and 2008. 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."

	2012	2011	2010	2009	2008
	(in thousands, except per share amounts)				
Statements of Income Data: [1]					
Revenues	$ 317,149	$ 306,005	$ 254,438	$ 235,206	$ 469,490
Depreciation, depletion and amortization	$ 206,336	$ 162,534	$ 134,700	$ 154,351	$ 135,687
Operating income (loss) [2]	$ (147,091)	$ (155,419)	$ (98,808)	$ (205,346)	$ 142,034
Income (loss) from continuing operations	$ (104,589)	$ (132,915)	$ (65,327)	$ (130,856)	$ 93,619
Net income (loss) [3]	$ (104,589)	$ (132,915)	$ 19,667	$ (77,368)	$ 181,520
Income (loss) attributable to Penn Virginia Corporation	$ (104,589)	$ (132,915)	$ (8,423)	$ (114,643)	$ 121,084
Preferred stock dividends	$ 1,687	$ —	$ —	$ —	$ —
Income (loss) attributable to common shareholders	$ (106,276)	$ (132,915)	$ (8,423)	$ (114,643)	$ 121,084
Common Stock Data: [1]					
Earnings (loss) per common share, basic					
Continuing operations	$ (2.22)	$ (2.90)	$ (1.44)	$ (2.99)	$ 2.23
Discontinued operations	$ —	$ —	$ 0.12	$ 0.37	$ 0.66
Gain on sale of discontinued operations	$ —	$ —	$ 1.13	$ —	$ —
Net income (loss)	$ (2.22)	$ (2.90)	$ (0.19)	$ (2.62)	$ 2.89
Earnings (loss) per common share, diluted					
Continuing operations	$ (2.22)	$ (2.90)	$ (1.44)	$ (2.99)	$ 2.22
Discontinued operations	$ —	$ —	$ 0.12	$ 0.37	$ 0.65
Gain on sale of discontinued operations	$ —	$ —	$ 1.13	$ —	$ —
Net income (loss)	$ (2.22)	$ (2.90)	$ (0.19)	$ (2.62)	$ 2.87
Weighted-average shares outstanding:					
Basic	47,919	45,784	45,553	43,811	41,760
Diluted	47,919	45,784	45,553	43,811	42,031
Actual shares outstanding at year-end	55,117	45,714	45,557	45,272	41,786
Dividends declared per share of common stock	$ 0.1125	$ 0.225	$ 0.225	$ 0.225	$ 0.225
Market value at year-end	$ 4.41	$ 5.29	$ 16.82	$ 21.29	$ 25.66
Number of shareholders	7,656	6,787	6,708	3,486	8,761
Balance Sheet and Other Financial Data: [1]					
Property and equipment, net	$ 1,723,359	$ 1,777,575	$ 1,705,584	$ 1,479,452	$ 1,646,215
Total assets	$ 1,842,989	$ 1,943,053	$ 1,944,600	$ 2,888,507	$ 2,996,565
Total debt	$ 594,759	$ 697,307	$ 506,536	$ 498,427	$ 539,438
Shareholders' equity	$ 895,116	$ 846,309	$ 980,276	$ 1,237,999	$ 1,222,442
Cash provided by operating activities	$ 241,458	$ 144,741	$ 79,839	$ 117,733	$ 246,587
Cash paid for capital expenditures	$ 370,907	$ 445,623	$ 405,994	$ 205,676	$ 547,058
Other Statistical Data:					
Total production (MBOE)	6,513	7,759	7,867	8,500	7,814
Proved reserves (MMBOE)	113	147	157	156	153

[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 2012, 2011, 2010, 2009 and 2008 included impairment charges of $104.5 million, $104.7 million, $46.0 million, $106.4 million and $20.0 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 oil, NGLs and natural gas in various domestic onshore regions. We have a geographically diverse asset base with active operations in Texas, the Mid-Continent and Mississippi regions. Our operations are concentrated in the Eagle Ford Shale, the Granite Wash, Haynesville Shale, Cotton Valley and Selma Chalk plays. As discussed in the Key Developments that follow, we sold our legacy natural gas assets in West Virginia, Kentucky and Virginia in July 2012. As of December 31, 2012, we had proved oil and natural gas reserves of approximately 113.5 MMBOE. Our current operations consist primarily of drilling unconventional horizontal development wells in shale formations.

We are currently focused on development and expansion in the Eagle Ford Shale in South Texas. We also pursue select drilling opportunities in the horizontal Granite Wash play in the 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, 2012	2011	2010
Total production (MBOE)	6,513	7,759	7,867
Daily production (BOEPD)	17,796	21,254	21,552
Product revenues, as reported	$ 310,484	$ 300,046	$ 251,336
Product revenues, as adjusted for derivatives	$ 338,802	$ 323,608	$ 284,816
Cash provided by operating activities	$ 241,458	$ 144,741	$ 79,839
Cash paid for capital expenditures	$ 370,907	$ 445,623	$ 405,994
Cash and cash equivalents at end of period	$ 17,650	$ 7,512	$ 120,911
Debt outstanding, net of discounts, at end of period	$ 594,759	$ 697,307	$ 506,536
Liquidation preference of convertible preferred stock outstanding at end of period	$ 115,000	$ —	$ —
Credit available under revolving credit facility at end of period [1]	$ 297,922	$ 199,600	$ 299,268
Net development wells drilled	27.8	33.4	40.0
Net exploratory wells drilled	4.9	6.5	4.4

[1] As reduced by outstanding borrowings and letters of credit.

Key Developments

Currently, the following general business developments and corporate actions have an important impact on the financial reporting and disclosure of our results of operations, financial position and cash flows: (i) drilling results in the Eagle Ford Shale and other plays, (ii) continuing to shift the focus of our production from natural gas to oil and NGLs, (iii) entering into a new five-year revolving credit facility, or the Revolver, (iv) completing an offering of common and preferred stock, (v) selling our legacy West Virginia, Kentucky and Virginia natural gas assets and related restructuring and exit activities and (vi) hedging a portion of our oil and natural gas production through calendar year 2014 to the levels permitted by the Revolver and our internal policies. We believe that these actions will provide sufficient liquidity in 2013 so that we will be able to fund our capital program.

Drilling Results and Future Development Plans

During 2012, we drilled a total of 32.7 net wells, including 29.5 net wells in the Eagle Ford Shale and 3.2 net wells in the Mid-Continent.

During 2012, we drilled 35 gross (29.5 net) operated wells in the Eagle Ford Shale, all of which were successful. Since December 2012, we have completed two gross (1.9 net) wells, bringing the total to 69 gross (56.2 net) producing wells, with three gross (2.7 net) wells being drilled. The initial 30-day average gross production rate for 59 of these wells with a 30-day production history was 651 BOEPD. Our Eagle Ford Shale production was approximately 6,377 net BOEPD during 2012, with oil comprising approximately 84 percent, NGLs approximately nine percent and natural gas approximately seven percent. We have allocated approximately 88 percent of our anticipated capital expenditures during 2013 to activities in the Eagle Ford Shale.

Included in the totals for 2012 presented above for the Eagle Ford Shale are four gross (2.9 net) exploratory wells and nine gross (8.1 net) development wells in Lavaca County, Texas drilled under a joint exploration agreement with an industry partner that we entered into in December 2011 to jointly explore a 13,500 acre area of mutual interest, or AMI. Under the terms of the agreement, we were required to commence drilling on six wells by September 1, 2012, as well as carry our partner for its working interest share of the costs of the first three wells, to earn our entire interest in the acreage. We fulfilled this requirement during the third quarter of 2012 and as a result, earned an approximately 60 percent interest in the acreage.

In December 2012, our 40 percent industry partner in the Lavaca County Eagle Ford Shale acreage elected to not participate in the last 17 initial unit wells to be drilled on this acreage. Upon the drilling of each of the initial unit wells, our industry partner will have no participatory rights in any subsequent wells drilled in such unit. We are presently seeking a partner to acquire a 40 percent working interest in the acreage in which our industry partner has elected not to participate.

Our remaining Eagle Ford Shale wells are located in Gonzales County, Texas. We are the operator of all of our Gonzales County acreage with an average working interest of approximately 84 percent.

In addition to the acreage earned in Lavaca County, we acquired approximately 4,100 net acres in the Eagle Ford Shale in Gonzales and Lavaca Counties, Texas in 2012 for approximately $10 million, increasing our net Eagle Ford Shale acreage position to approximately 32,500 net acres.

Production Focus

Since 2011, we have allocated approximately 80 percent of our capital expenditures to explore and develop oil- and NGL-rich areas in the Eagle Ford Shale. Approximately 56 percent of our total production during the quarter ended December 31, 2012 was attributable to oil and NGLs, an increase of approximately 21 percent over the corresponding prior year period. For the quarter ended December 31, 2012, approximately 83 percent of our product revenues were attributable to oil and NGLs, an increase of approximately 17 percent over the corresponding prior year period.

Completion of a New Credit Facility

In September 2012, we entered into the Revolver to replace our previous revolving credit facility that was entered into in August 2011. The Revolver provides for a $300 million revolving credit commitment and an accordion feature to expand commitment amounts by up to an aggregate of $300 million upon receiving additional commitments from one or more lenders. The Revolver also includes a $20 million sublimit for the issuance of letters of credit. The Revolver has an initial borrowing base of $300 million, which is $70 million higher than the borrowing base under our previous revolving credit facility at the time it was replaced by the Revolver. The applicable interest rate margin under the Revolver ranges from LIBOR plus 1.50 percent to LIBOR plus 2.50 percent, depending upon the amount drawn as a percentage of the commitment. This rate is unchanged from our previous credit facility. The maximum leverage ratio (net debt divided by EBITDAX, as defined in the Revolver) is 4.50 through December 31, 2013, 4.25 through June 30, 2014 and 4.00 through maturity in 2017. The borrowing base under the Revolver will be re-determined based on a semi-annual review of our total proved crude oil, NGL and natural gas reserves starting in the spring of 2013.

Common and Preferred Stock Offering

In October 2012, we completed a registered offering of 9.2 million shares of our common stock that provided approximately $44 million of proceeds net of underwriting fees and issuance costs. Concurrently, we completed a registered offering of 1,150,000 depositary shares each representing 1/100th interest in a share of our 6% Series A Convertible Perpetual Preferred Stock, or the 6% Preferred Stock, that provided approximately $110 million of proceeds net of underwriting fees and issuance costs. The proceeds from the combined offerings were used to fully repay outstanding borrowings under the Revolver and for general corporate purposes.

Disposition of Appalachian Assets

In July 2012, we sold our legacy natural gas assets in West Virginia, Kentucky and Virginia for approximately $100 million, excluding transaction costs and before customary purchase and sale adjustments. The assets sold included vertical and horizontal coalbed methane and vertical conventional properties, a gathering system and royalty interests. These assets had net production of approximately 20 MMcfe per day (3,333 BOEPD) and estimated proved reserves of approximately 106 Bcfe (17.7 MMBOE), of which 96 percent was proved developed and almost 100 percent was natural gas. An impairment charge of $28.6 million was recognized in the second quarter of 2012 with respect to these assets.

During 2012, we recorded certain restructuring and exit costs in connection with the sale, including those attributable to the closing of our office in Canonsburg, Pennsylvania. Furthermore, we have a contractual commitment for certain firm transportation capacity in the Appalachian region that expires in 2022 and, as a result of the sale, we no longer have production to satisfy this commitment. While we intend to sell our unused firm transportation in the future to the extent possible, we recorded a charge of $17.3 million during the third quarter of 2012 representing the liability for estimated discounted future net cash outflows over the remaining term of the contract.

Commodity Hedging Activities

For 2013, we have approximately 58 percent of our estimated oil production hedged at weighted-average floor/swap and ceiling prices of between $97.35 and $100.99 per barrel. For 2014, we have approximately 16 percent of our estimated oil production hedged at a weighted-average swap price of $100.33 per barrel.

For 2013, we have approximately 55 percent of our estimated natural gas production hedged at weighted-average floor/swap and ceiling prices of $3.76 and $4.19 per MMBtu. We have 5,000 MMBtu per day hedged in the first quarter of 2014 with a floor/swap and ceiling prices of $4.00 and $4.50 per MMBtu. We do not have any NGLs hedged.

Results of Operations

Year Ended December 31, 2012 Compared to the Year Ended December 31, 2011

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

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Total production:				
Crude oil (MBbl)	2,252	1,283	969	76 %
NGL (MBbl)	884	907	(23)	(3)%
Natural gas (MMcf)	20,261	33,410	(13,149)	(39)%
Total production (MBOE)	6,513	7,759	(1,246)	(16)%
Realized prices, before derivatives:				
Crude oil ($/Bbl)	$ 101.95	$ 93.19	$ 8.76	9 %
NGL ($/Bbl)	35.13	47.83	(12.70)	(27)%
Natural gas ($/Mcf)	2.46	4.10	(1.64)	(40)%
Total ($/BOE)	$ 47.67	$ 38.67	$ 9.00	23 %
Revenues				
Crude oil	$ 229,572	$ 119,582	$ 109,990	92 %
NGL	31,051	43,394	(12,343)	(28)%
Natural gas	49,861	137,070	(87,209)	(64)%
Total product revenues	310,484	300,046	10,438	3 %
Gain on sales of property and equipment	4,282	3,570	712	20 %
Other income	2,383	2,389	(6)	— %
Total revenues	317,149	306,005	11,144	4 %
Operating expenses				
Lease operating	31,266	36,988	5,722	15 %
Gathering, processing and transportation	14,196	15,157	961	6 %
Production and ad valorem taxes	10,634	13,690	3,056	22 %
General and administrative	45,900	48,328	2,428	5 %
Exploration	34,092	78,943	44,851	57 %
Depreciation, depletion and amortization	206,336	162,534	(43,802)	(27)%
Impairments	104,484	104,688	204	— %
Loss on firm transportation commitment	17,332	—	(17,332)	NM
Other	—	1,096	1,096	100 %
Total operating expenses	464,240	461,424	(2,816)	(1)%
Operating loss	(147,091)	(155,419)	8,328	5 %
Other income (expense)				
Interest expense	(59,339)	(56,216)	(3,123)	(6)%
Loss on extinguishment of debt	(3,164)	(25,421)	22,257	88 %
Derivatives	36,187	15,651	20,536	131 %
Other	116	335	(219)	(65)%
Loss before income taxes	(173,291)	(221,070)	47,779	22 %
Income tax benefit	68,702	88,155	(19,453)	(22)%
Net loss	(104,589)	(132,915)	28,326	21 %
Preferred stock dividends	(1,687)	—	(1,687)	NM
Loss attributable to common shareholders	$ (106,276)	$ (132,915)	$ 26,639	20 %

NM - Not meaningful

Production

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

Crude Oil	Year Ended December 31, 2012	2011	Favorable (Unfavorable)	Year Ended December 31, 2012	2011	Favorable (Unfavorable)	% Change
	(MBbl)			(Bbl per day)			
Texas							
Eagle Ford Shale	1,959.6	751.2	1,208.4	5,354.1	2,058.1	3,296.0	161 %
East Texas	71.1	117.5	(46.4)	194.3	321.9	(127.6)	(39)%
Mid-Continent	206.2	395.1	(188.9)	563.4	1,082.6	(519.2)	(48)%
Mississippi	14.1	18.9	(4.8)	38.5	51.7	(13.2)	(25)%
Appalachia	1.0	0.5	0.5	2.7	1.3	1.4	105 %
	2,251.9	1,283.2	968.8	6,153.0	3,515.5	2,637.4	75 %

NGLs	Year Ended December 31, 2012	2011	Favorable (Unfavorable)	Year Ended December 31, 2012	2011	Favorable (Unfavorable)	% Change
	(MBbl)			(Bbl per day)			
Texas							
Eagle Ford Shale	205.2	54.9	150.3	560.7	150.4	410.3	274 %
East Texas	280.7	440.3	(159.6)	766.9	1,206.3	(439.4)	(36)%
Mid-Continent	397.2	411.1	(13.9)	1,085.2	1,126.3	(41.1)	(3)%
Mississippi	—	—	—	—	—	—	— %
Appalachia	0.8	0.9	(0.1)	2.2	2.5	(0.3)	(11)%
	884.0	907.2	(23.3)	2,415.0	2,485.5	(70.5)	(3)%

Natural Gas	Year Ended December 31, 2012	2011	Favorable (Unfavorable)	Year Ended December 31, 2012	2011	Favorable (Unfavorable)	% Change
	(MMcfe)			(MMcfe per day)			
Texas							
Eagle Ford Shale	1,015	277	738	2.8	0.8	2.0	266 %
East Texas	5,909	9,393	(3,484)	16.1	25.7	(9.6)	(37)%
Mid-Continent	3,646	8,244	(4,598)	10.0	22.6	(12.6)	(56)%
Mississippi	4,997	6,441	(1,444)	13.7	17.6	(3.9)	(22)%
Appalachia	4,695	9,055	(4,360)	12.8	24.8	(12.0)	(48)%
	20,261	33,410	(13,148)	55.4	91.5	(36.1)	(39)%

Combined Total	Year Ended December 31, 2012	2011	Favorable (Unfavorable)	Year Ended December 31, 2012	2011	Favorable (Unfavorable)	% Change
	(MBOE)			(BOE per day)			
Texas							
Eagle Ford Shale	2,334	852	1,482	6,377	2,334	4,043	174 %
East Texas	1,337	2,123	(786)	3,653	5,816	(2,163)	(37)%
Mid-Continent	1,211	2,180	(969)	3,309	5,973	(2,664)	(44)%
Mississippi	847	1,092	(245)	2,314	2,993	(678)	(22)%
Appalachia	784	1,511	(727)	2,143	4,138	(1,996)	(48)%
	6,513	7,759	(1,245)	17,796	21,254	(3,458)	(16)%

Certain results in the tables above may not calculate due to rounding.

The decline in total production during 2012 compared to 2011 was due primarily to natural production declines as well as the effect of the sale of Appalachian and Arkoma Basin natural gas properties in July 2012 and August 2011, respectively. The effect of the sale of the Appalachian properties was approximately 4.4 Bcfe (700 MBOE) and the Arkoma Basin properties was approximately 2.0 Bcfe (333 MBOE). The natural declines in production from our remaining natural gas properties were partially offset by an increase in oil, NGL and natural gas production attributable to our drilling activity in the Eagle Ford Shale. Approximately 48% of total production in 2012 was attributable to oil and NGLs, which represents an increase of approximately 43% over the previous year. During 2012, our Eagle Ford Shale production of 2,334 MBbl represented approximately 36% of our total production. We had approximately 852 MBbls of production from this play during 2011.

Product Revenues and Prices

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

Crude Oil	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2012	2011	(Unfavorable)	2012	2011	(Unfavorable)
				($ per Bbl)		
Texas						
Eagle Ford Shale	$ 202,479	$ 70,399	$ 132,080	$ 103.33	$ 93.72	$ 9.61
East Texas	6,862	11,074	(4,212)	96.51	94.25	2.26
Mid-Continent	18,667	36,145	(17,478)	90.55	91.48	(0.93)
Mississippi	1,477	1,924	(447)	104.66	101.80	2.86
Appalachia	87	40	47	91.29	80.00	11.29
	$ 229,572	$ 119,582	$ 109,990	$ 101.95	$ 93.19	$ 8.76

NGLs	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2012	2011	(Unfavorable)	2012	2011	(Unfavorable)
				($ per Bbl)		
Texas						
Eagle Ford Shale	$ 6,451	$ 2,817	$ 3,634	$ 31.43	$ 51.22	$ (19.79)
East Texas	10,195	21,936	(11,741)	36.32	49.82	(13.50)
Mid-Continent	14,365	18,595	(4,230)	36.16	45.23	(9.07)
Mississippi	—	—	—	—	—	—
Appalachia	40	46	(6)	51.61	51.11	0.50
	$ 31,051	$ 43,394	$ (12,343)	$ 35.13	$ 47.83	$ (12.70)

Natural Gas	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2012	2011	(Unfavorable)	2012	2011	(Unfavorable)
				($ per Mcfe)		
Texas						
Eagle Ford Shale	$ 2,593	$ 1,015	$ 1,578	$ 2.56	$ 3.66	$ (1.10)
East Texas	13,607	37,057	(23,450)	2.30	3.95	(1.65)
Mid-Continent	7,920	35,315	(27,395)	2.17	4.28	(2.11)
Mississippi	14,387	27,047	(12,660)	2.88	4.20	(1.32)
Appalachia	11,354	36,636	(25,282)	2.42	4.05	(1.63)
	$ 49,861	$ 137,070	$ (87,209)	$ 2.46	$ 4.10	$ (1.64)

Combined Total	Year Ended December 31,		Favorable	Year Ended December 31,		Favorable
	2012	2011	(Unfavorable)	2012	2011	(Unfavorable)
				($ per BOE)		
Texas						
Eagle Ford Shale	$ 211,523	$ 74,231	$ 137,292	$ 90.63	$ 87.13	$ 3.50
East Texas	30,664	70,067	(39,403)	22.93	33.00	(10.07)
Mid-Continent	40,952	90,055	(49,103)	33.82	41.31	(7.49)
Mississippi	15,864	28,971	(13,107)	18.72	26.53	(7.81)
Appalachia	11,481	36,722	(25,241)	14.64	24.30	(9.66)
	$ 310,484	$ 300,046	$ 10,438	$ 47.67	$ 38.67	$ 9.00

As illustrated below, higher oil production volume coupled with improved oil prices were the significant factors for increasing revenues. The increase was partially offset by lower natural gas and NGL production volumes and prices. Included in the price variance for natural gas was approximately $0.7 million of unfavorable adjustments attributable to the change in prices associated with gas imbalances due to us from partners in the Mid-Continent region.

The following table provides an analysis of the change in our revenues for 2012 as compared to 2011:

	Revenue Variance Due to		
	Volume	Price	Total
Crude oil	$ 90,274	$ 19,716	$ 109,990
NGL	(1,110)	(11,233)	(12,343)
Natural gas	(53,946)	(33,263)	(87,209)
	$ 35,218	$ (24,780)	$ 10,438

Effects of Derivatives

Our oil and gas 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 instruments to hedge oil and gas prices. In 2012 and 2011, we received $28.3 million and $23.6 million, respectively, in cash settlements of oil and gas derivatives.

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

	Year Ended December 31,		Favorable	
	2012	2011	(Unfavorable)	% Change
Crude oil revenues as reported	$ 229,572	$ 119,582	$ 109,990	92 %
Cash settlements on crude oil derivatives, net	8,428	1,404	7,024	500 %
Crude oil revenues adjusted for derivatives	$ 238,000	$ 120,986	$ 117,014	97 %
Crude oil prices per Bbl, as reported	$ 101.95	$ 93.19	$ 8.76	9 %
Cash settlements on crude oil per Bbl	3.74	1.09	2.65	243 %
Crude oil prices per Bbl adjusted for derivatives	$ 105.69	$ 94.28	$ 11.41	12 %
Natural gas revenues as reported	$ 49,861	$ 137,070	$ (87,209)	(64)%
Cash settlements on natural gas derivatives, net	19,890	22,158	(2,268)	(10)%
Natural gas revenues adjusted for derivatives	$ 69,751	$ 159,228	$ (89,477)	(56)%
Natural gas prices per Mcf, as reported	$ 2.46	$ 4.10	$ (1.64)	(40)%
Cash settlements on natural gas derivatives per Mcf	0.98	0.66	0.32	48 %
Natural gas prices per Mcf adjusted for derivatives	$ 3.44	$ 4.76	$ (1.32)	(28)%

Gain on Sales of Property and Equipment

In the third quarter of 2012 and as further adjusted in the fourth quarter, we recognized a gain of $3.3 million on the sale of certain of our Appalachian assets for proceeds of $95.7 million, net of transaction costs. In 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, and recognized a gain of $3.3 million. We also recognized a gain of $0.6 million in 2012 attributable to the sale of our remaining undeveloped acreage in those counties. In addition, we recognized several individually insignificant gains on the sale of property, equipment, tubular inventory and well material during both 2012 and 2011.

Other Income

Other income, which includes ancillary gathering, transportation, compression and water disposal fees and other miscellaneous operating income net of marketing and related expenses, was relatively unchanged during 2012 as compared to 2011.

Operating Expenses

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

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Lease operating	$ 4.80	$ 4.77	$ (0.03)	(1)%
Gathering, processing and transportation	2.19	1.95	(0.24)	(12)%
Production and ad valorem taxes	1.63	1.76	0.13	7 %
General and administrative excluding share-based compensation and restructuring charges	5.87	4.97	(0.90)	(18)%
General and administrative	7.05	6.23	(0.82)	(13)%
Depreciation, depletion and amortization	31.68	20.95	(10.73)	(51)%

Lease Operating

Lease operating expense decreased on an absolute basis during 2012 due primarily to the effect of the sale of our higher-cost Appalachian and Arkoma Basin properties. In addition to the effect of property sales, we incurred lower repair and maintenance expenses and lower compression costs during 2012. Cost decreases were partially offset by higher environmental and regulatory compliance, chemical treatment, field contracting and well tending costs attributable to our significantly expanded oil drilling program.

Gathering, Processing and Transportation

Gathering, processing and transportation charges increased slightly during 2012, despite lower overall production volumes, due primarily to higher processing costs associated with NGLs and higher transportation costs in the Appalachian region in 2012 for periods prior to the sale.

Production and Ad Valorem Taxes

Production and ad valorem taxes decreased during 2012 due primarily to Oklahoma severance tax rebates of $2.8 million attributable to horizontal and ultra-deep wells for the period of July 1, 2009 through June 30, 2011. Reductions were also recognized for production taxes on certain Texas wells in 2012 and for a property tax recovery on West Virginia wells in 2011. Production taxes also decreased due to the Appalachian asset sale as well as lower overall natural gas volumes and prices in 2012 as compared to 2011. As a percentage of product revenues, production and ad valorem taxes decreased to 3.4% during 2012 from 4.6% during 2011.

General and Administrative

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

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Recurring general and administrative expenses	$ 37,547	$ 38,547	$ 1,000	3%
Share-based compensation (liability-classified)	714	—	(714)	NM
Share-based compensation (equity-classified)	6,347	7,430	1,083	15%
Restructuring expenses	1,292	2,351	1,059	45%
	$ 45,900	$ 48,328	$ 2,428	5%

Recurring general and administrative expenses decreased due to reduced headcount and lower support costs following the sale of our Appalachian and Arkoma Basin properties. Liability-classified share-based compensation is attributable to our performance-based restricted stock units, or PBRSUs, issued in 2012, which are payable in cash in 2015 upon achievement of specified market-based performance metrics. Equity-classified share-based compensation charges attributable to stock options and restricted stock units, which represent non-cash expenses, decreased during 2012 due primarily to a lower number of awards granted. Restructuring expenses for both the 2012 and 2011 periods include termination benefits and office relocation costs. The 2012 charge includes a provision for lease costs associated with the closing of our Canonsburg, Pennsylvania office, partially offset by a favorable adjustment to the lease obligation for our former Tulsa, Oklahoma office due to a change in estimated sub-lease rental income.

Exploration

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

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Unproved leasehold amortization	$ 32,634	$ 42,076	$ 9,442	22%
Geological and geophysical costs	816	11,202	10,386	93%
Dry hole costs	—	18,864	18,864	100%
Drilling rig charges	—	4,620	4,620	100%
Other, primarily delay rentals	642	2,181	1,539	71%
	$ 34,092	$ 78,943	$ 44,851	57%

Unproved leasehold amortization declined during 2012 as costs related to successful Eagle Ford Shale wells were transferred to proved properties. Geological and geophysical costs decreased during 2012 because our efforts in 2012 were concentrated on development drilling in the Eagle Ford Shale whereas in 2011 we conducted exploratory prospect activities in multiple areas. Dry hole costs in 2011 related to several unsuccessful wells in the Mid-Continent region. We recorded rig-related charges in 2011 in connection with the suspension of our exploratory drilling program in the Marcellus Shale.

Depreciation, Depletion and Amortization (DD&A)

The following table sets forth the nature of the DD&A variances for the periods presented:

	DD&A Variance Due to		
	Production	Rates	Favorable (Unfavorable)
Year ended December 31, 2012 compared to 2011	$ 26,103	$ (69,905)	$ (43,802)

The effect of lower overall production volumes on DD&A was more than offset by higher depletion rates associated with oil and NGL production. Our average DD&A rate increased to $31.68 per BOE for 2012 from $20.95 per BOE for 2011 due primarily to higher capitalized finding and development costs attributable to our oil wells in the Eagle Ford Shale as well as lower natural gas reserves due to revisions.

Impairments

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

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Oil and gas properties	$ 103,417	$ 104,688	$ 1,271	1%
Other - tubular inventory and well materials	1,067	—	(1,067)	NM
	$ 104,484	$ 104,688	$ 204	—%

In 2012, we recognized a $28.4 million impairment of our legacy assets in West Virginia, Kentucky and Virginia triggered by the expected disposition of these properties, and a $75.0 million impairment of our Marcellus Shale assets due primarily to market declines in natural gas prices and the resultant reduction in proved natural gas reserves. In 2012, we also recognized an impairment of certain tubular inventory and well materials triggered primarily by declines in asset quality. In 2011, we recognized an impairment of our Arkoma Basin assets for $71.1 million, which was triggered by the expected disposition of those properties. Also during 2011, we recognized impairments of our horizontal coal bed methane properties in the Appalachian region for $26.6 million and certain dry-gas properties in Mississippi for $6.8 million, in each case due primarily to market declines in natural gas prices.

Loss on Firm Transportation Commitment

We have a contractual commitment for certain firm transportation capacity in the Appalachian region that expires in 2022 and, as a result of the recently completed sale of our West Virginia, Kentucky and Virginia assets, we no longer have production to satisfy this commitment. Accordingly, we recorded a charge of $17.3 million during the third quarter of 2012 representing the liability for estimated discounted future net cash outflows over the remaining term of the contract.

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 in 2011 that originated in prior years due to lower settlement rates.

Interest Expense

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

	Year Ended December 31,		Favorable	
	2012	2011	(Unfavorable)	% Change
Interest on borrowings and related fees	$ 56,079	$ 51,384	$ (4,695)	(9)%
Accretion of original issue discount	1,367	3,427	2,060	60 %
Amortization of debt issuance costs	2,695	3,380	685	20 %
Capitalized interest	(803)	(1,983)	(1,180)	(60)%
Other, net	1	8	7	88 %
	$ 59,339	$ 56,216	$ (3,123)	(6)%

The issuance of our 7.25% Senior Notes due 2019, or the 2019 Senior Notes, and borrowings under the Revolver, partially offset by the repurchase of approximately 98% of our outstanding 4.50% Convertible Senior Subordinated Notes due 2012, or the Convertible Notes, with an effective interest rate of 8.5%, resulted in an approximate $107 million higher weighted-average balance of debt outstanding during 2012 compared to 2011. Accordingly, interest expense increased due to a higher average outstanding principal balance despite lower effective interest rates attributable to the 2019 Senior Notes and the Revolver. Capitalized interest was lower during 2012 due to lower carrying values on eligible capital projects.

Loss on Extinguishment of Debt

When we entered into the Revolver in September 2012, we expensed issuance costs of $3.2 million attributable to our previous revolving credit facility. During 2011, we expensed $1.2 million attributable to a change in the composition of the bank syndicate for our previous revolving credit facility. 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 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 fees paid in cash.

Derivatives

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

	Year Ended December 31,		Favorable	
	2012	2011	(Unfavorable)	% Change
Oil and gas derivative unrealized gain (loss)	$ 6,463	$ (9,140)	$ 15,603	171 %
Oil and gas derivative realized gain	28,318	23,562	4,756	20 %
Interest rate swap unrealized loss	—	(2,589)	2,589	100 %
Interest rate swap realized gain	1,406	3,818	(2,412)	(63)%
	$ 36,187	$ 15,651	$ 20,536	131 %

We received cash settlements of $29.7 million during 2012 and $27.4 million during 2011. The cash settlements in 2012 and 2011 included $1.2 million and $2.9 million attributable to the termination of our interest rate swap agreements during those periods. The increase in the unrealized gain on commodity derivatives was due primarily to oil and natural gas prices declining below our hedged prices.

Other

Other income decreased during 2012 due primarily to lower interest income earned on average cash balances.

Income Taxes

The effective tax benefit rate during 2012 was 39.6% compared to 39.9% for 2011. Due to the operating losses incurred, we recognized an income tax benefit during both periods. In addition, the effective tax rates for 2012 and 2011 included a deferred tax asset valuation allowance due primarily to the inability to recognize tax benefits for certain state net operating losses.

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:				
Crude oil (MBbl)	1,283	709	574	81 %
NGL (MBbl)	907	672	235	35 %
Natural gas (MMcf)	33,410	38,919	(5,509)	(14)%
Total production (MBOE)	7,759	7,867	(108)	(1)%
Realized prices, before derivatives:				
Crude oil ($/Bbl)	$ 93.19	75.56	17.63	23 %
NGL ($/Bbl)	47.83	39.69	8.14	21 %
Natural gas ($/Mcf)	4.10	4.40	(0.30)	(7)%
Total ($/BOE)	$ 38.67	$ 31.95	$ 6.72	21 %
Revenues				
Crude oil	$ 119,582	$ 53,532	$ 66,050	123 %
NGL	43,394	26,663	16,731	63 %
Natural gas	137,070	171,141	(34,071)	(20)%
Total product revenues	300,046	251,336	48,710	19 %
Gain on sale 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, net of tax	—	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
Net 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 geographic region for the periods presented:

Crude Oil	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
	(MBbl)			(Bbl per day)			
Texas							
Eagle Ford Shale	751.2	—	751.2	2,058.1	—	2,058.1	NM
East Texas	117.5	113.5	4.0	321.9	311.0	10.9	4 %
Mid-Continent	395.1	559.3	(164.2)	1,082.6	1,532.3	(449.7)	(29)%
Mississippi	18.9	22.9	(4.0)	51.7	62.7	(11.0)	(17)%
Appalachia	0.5	5.1	(4.6)	1.3	14.0	(12.7)	(90)%
Gulf Coast (Divested)	—	7.7	(7.7)	—	21.1	(21.1)	(100)%
	1,283.2	708.5	574.7	3,515.5	1,941.1	1,574.5	81 %

NGLs	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
	(MBbl)			(Bbl per day)			
Texas							
Eagle Ford Shale	54.9	—	54.9	150.4	—	150.4	NM
East Texas	440.3	389.1	51.2	1,206.3	1,066.0	140.3	13 %
Mid-Continent	411.1	274.4	136.7	1,126.3	751.8	374.5	50 %
Mississippi	—	—	—	—	—	—	— %
Appalachia	0.9	1.4	(0.5)	2.5	3.8	(1.3)	(36)%
Gulf Coast (Divested)	—	6.9	(6.9)	—	18.9	(18.9)	(100)%
	907.2	671.8	235.4	2,485.5	1,840.5	645.0	35 %

Natural Gas	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
	(MMcfe)			(MMcfe per day)			
Texas							
Eagle Ford Shale	277	—	277	0.8	—	0.8	NM
East Texas	9,393	10,510	(1,117)	25.7	28.8	(3.1)	(11)%
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)%
Appalachia	9,055	10,358	(1,303)	24.8	28.4	(3.6)	(13)%
Gulf Coast (Divested)	—	208	(208)	—	0.6	(0.6)	(100)%
	33,410	38,919	(5,509)	91.5	106.7	(15.2)	(14)%

Combined Total	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable (Unfavorable)	% Change
	(MBOE)			(BOE per day)			
Texas							
Eagle Ford Shale	852	—	852	2,334	—	2,334	NM
East Texas	2,123	2,254	(131)	5,816	6,175	(359)	(6)%
Mid-Continent	2,180	2,557	(377)	5,973	7,005	(1,032)	(15)%
Mississippi	1,092	1,274	(182)	2,993	3,490	(497)	(14)%
Appalachia	1,511	1,733	(222)	4,138	4,747	(609)	(13)%
Gulf Coast (Divested)	—	49	(49)	—	135	(135)	(100)%
	7,759	7,867	(109)	21,254	21,552	(298)	(1)%

Certain results in the tables above may not calculate due to rounding.

The decline in production during 2011 compared to 2010 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 selling our high-cost Arkoma Basin natural gas properties. The effect of the sale of the Arkoma Basin properties was approximately 2.0 Bcfe (333 MBOE). 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 in 2011 was attributable to oil and NGLs, an increase over the previous year of approximately 59%. During 2011, our Eagle Ford Shale production of 852 MBbls 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 geographic region for the periods presented:

Crude Oil	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2011	**2010**	**(Unfavorable)**	**2011**	**2010**	**(Unfavorable)**
				($ per Bbl)		
Texas						
Eagle Ford Shale	$ 70,399	$ —	$ 70,399	$ 93.72	$ —	93.72
East Texas	11,074	8,844	2,230	94.25	77.92	16.33
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
Appalachia	40	164	(124)	80.00	32.16	47.84
Gulf Coast (Divested)	—	598	(598)	—	77.66	(77.66)
	$ 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						
Eagle Ford Shale	$ 2,817	$ —	$ 2,817	$ 51.22	$ —	$ 51.22
East Texas	21,936	15,150	6,786	49.82	38.94	10.88
Mid-Continent	18,595	11,152	7,443	45.23	40.64	4.59
Appalachia	—	51	(51)	—	36.43	(36.43)
Mississippi	46	—	46	51.11	—	51.11
Gulf Coast (Divested)	—	310	(310)	—	44.93	(44.93)
	$ 43,394	$ 26,663	$ 16,731	$ 47.83	$ 39.69	$ 8.14

Natural Gas	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2011	**2010**	**(Unfavorable)**	**2011**	**2010**	**(Unfavorable)**
				($ per Mcfe)		
Texas						
Eagle Ford Shale	$ 1,015	$ —	$ 1,015	$ 3.66	$ —	$ 3.66
East Texas	37,057	43,247	(6,190)	3.95	4.11	(0.16)
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)
Appalachia	36,636	45,581	(8,945)	4.05	4.40	(0.35)
Gulf Coast (Divested)	—	1,268	(1,268)	—	6.10	(6.10)
	$ 137,070	$ 171,141	$ (34,071)	$ 4.10	$ 4.40	$ (0.30)

Combined Total	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2011	**2010**	**(Unfavorable)**	**2011**	**2010**	**(Unfavorable)**
				($ per BOE)		
Texas						
Eagle Ford Shale	$ 74,231	$ —	$ 74,231	$ 87.13	$ —	$ 87.13
East Texas	70,067	67,241	2,826	33.00	29.83	3.17
Mid-Continent	90,055	101,022	(10,967)	41.31	39.51	1.80
Mississippi	28,971	35,101	(6,130)	26.53	27.55	(1.02)
Appalachia	36,722	45,796	(9,074)	24.30	26.43	(2.13)
Gulf Coast (Divested)	—	2,176	(2,176)	—	44.41	(44.41)
	$ 300,046	$ 251,336	$ 48,710	$ 38.67	$ 31.95	$ 6.72

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 lower natural gas production volumes and prices.

The following table provides an analysis of the change in our revenues for 2011 as compared to 2010.

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

Effects of Derivatives

In 2011 and 2010, we received $23.6 million and $33.5 million, respectively, in cash settlements of oil and gas derivatives.

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

	Year Ended December 31,		Favorable	
	2011	2010	(Unfavorable)	% Change
Crude oil revenues as reported	$ 119,582	$ 53,532	$ 66,050	123 %
Cash settlements on crude oil derivatives	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	$ 17.63	23 %
Cash settlements on crude oil derivatives per Bbl	1.09	(0.61)	1.70	279 %
Crude oil prices per Bbl adjusted for derivatives	$ 94.28	$ 74.95	$ 19.33	26 %
Natural gas revenues as reported	$ 137,070	$ 171,141	$ (34,071)	(20)%
Cash settlements on natural gas derivatives	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	$ (0.30)	(7)%
Cash settlements on natural gas derivatives per Mcf	0.66	0.87	(0.21)	(24)%
Natural gas prices per Mcf adjusted for derivatives	$ 4.76	$ 5.27	$ (0.51)	(10)%

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, and recognized a gain of $3.3 million. In addition, we recognized several individually insignificant gains on the sale of property, equipment, tubular inventory and well materials during both 2011 and 2010.

Other Income

Other income, which includes ancillary gathering, transportation, compression and water disposal fees, net of marketing and related expenses, as well as other miscellaneous operating income, decreased marginally during 2011 as compared to 2010.

Operating Expenses

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

	Year Ended December 31,		Favorable	
	2011	2010	(Unfavorable)	% Change
Lease operating	$ 4.77	$ 4.55	$ (0.22)	(5)%
Gathering, processing and transportation	1.95	1.80	(0.15)	(8)%
Production and ad valorem taxes	1.76	1.77	0.01	1 %
General and administrative excluding share-based compensation and restructuring charges	4.97	5.39	0.42	8 %
General and administrative	6.23	7.42	1.19	16 %
Depreciation, depletion and amortization	20.95	17.12	(3.83)	(22)%

Lease Operating

Lease operating expense increased during 2011 due primarily 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,		Favorable	
	2011	2010	(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,		Favorable	
	2011	2010	(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 suspension of our drilling program in the Marcellus Shale.

Depreciation, Depletion and Amortization

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

	DD&A Variance Due to		
	Production	Rates	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 $20.95 per BOE for 2011 from $17.12 per BOE 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)	(143)%
Other - tubular inventory and well materials	—	2,892	2,892	100 %
	$ 104,688	$ 45,959	$ (58,729)	(128)%

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. Also during 2011, we recognized impairments of our horizontal coal bed methane properties in the Appalachian region for $26.6 million and certain dry-gas properties in Mississippi for $6.8 million, in each case 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 total interest expense for the periods presented:

	Year Ended December 31, 2011	2010	Favorable (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, partially 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 compared to 2010. Accordingly, interest expense increased due to a higher average outstanding principal balance despite lower effective interest rates attributable to the 2019 Senior Notes and the Revolver. Capitalized interest was lower during 2011 due to lower 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 a change in the composition of the bank syndicate for our previous revolving credit facility.

Derivatives

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

	Year Ended December 31, 2011	2010	Favorable (Unfavorable)	% Change
Oil and gas derivative unrealized gain (loss)	$ (9,140)	$ 3,213	$ (12,353)	(384)%
Oil and gas derivative realized gain	23,562	33,480	(9,918)	(30)%
Interest rate swap unrealized gain	(2,589)	5,875	(8,464)	(144)%
Interest rate swap realized loss	3,818	(662)	4,480	(677)%
	$ 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 in 2011 included $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 included a deferred tax asset valuation allowance due primarily to the inability to recognize a tax benefit for certain state net operating losses.

Liquidity and Capital Resources

Sources of Liquidity

We have no debt maturities until 2016. Our business strategy contemplates capital expenditures in excess of our projected operating cash flows for 2013. 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 2013 capital program with operating cash flows and borrowings under the Revolver.

In September 2012, we entered into the Revolver, which replaced our previous revolving credit facility. The Revolver provides for a $300 million revolving commitment, including a $20 million sublimit for the issuance of letters of credit. The Revolver has an accordion feature that allows us to increase the commitment by up to an additional aggregate of $300 million upon receiving additional commitments from one or more lenders. The Revolver is governed by a borrowing base calculation, and the availability under the Revolver may not exceed the lesser of the aggregate commitments and the borrowing base. The initial borrowing base under the Revolver is $300 million and will be re-determined based on a semi-annual review of our total proved oil, NGL and natural gas reserves starting in the spring of 2013. The Revolver is available to us for general purposes, including working capital, capital expenditures and acquisitions. The Revolver matures in September 2017.

As of February 15, 2013, we had $270.2 million of unused borrowing capacity available to us under the Revolver. The borrowing capacity is determined by reducing the revolving commitment of $300 million by outstanding borrowings of $28.0 million and outstanding letters of credit of $1.8 million.

The following table summarizes our borrowing activity under the Revolver and our previous credit facility during the periods presented

	Borrowings Outstanding		
	Weighted-Average	Maximum	Weighted-Average Rate
Three months ended December 31, 2012	$ 16,152	$ 107,000	2.0673%
Year ended December 31, 2012	$ 102,358	$ 190,000	2.1309%

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, typically through the use of collar, swap and swaption contracts. The level of our hedging activity and duration of the instruments employed depend on our cash flow at risk, available hedge prices and our operating strategy. During 2012, our commodity derivatives portfolio provided $8.4 million of cash inflows related to lower than anticipated prices received for our oil production and $19.9 million of cash inflows attributable to lower than anticipated prices received for our natural gas production.

For 2013, we have hedged approximately 58 percent of our estimated crude oil production, at weighted average floor/swap and ceiling prices of between $97.35 and $100.99 per barrel. In addition, we have hedged approximately 55 percent of our estimated natural gas production for 2013, at a weighted average floor/swap and ceiling prices of $3.76 and $4.19 per MMBtu.

Cash Flows

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

	Year Ended December 31, 2012	Year Ended December 31, 2011	Variance
Cash flows from operating activities			
Operating cash flows, net	$ 217,708	$ 182,948	$ 34,760
Working capital changes, net	20,157	(12,165)	32,322
Commodity derivative settlements received, net:			—
Crude oil	8,427	1,404	7,023
Natural gas	19,890	22,157	(2,267)
Interest payments, net of amounts capitalized	(54,808)	(44,589)	(10,219)
Income tax refunds received (payments made), net	32,603	(210)	32,813
Transaction costs paid for extinguishment of debt	(20)	(2,965)	2,945
Restructuring and exit costs paid	(2,499)	(1,839)	(660)
Net cash provided by operating activities	241,458	144,741	96,717
Cash flows from investing activities			
Capital expenditures - property and equipment	(370,907)	(445,623)	74,716
Proceeds from sales of assets and other, net	96,899	39,468	57,431
Net cash used in investing activities	(274,008)	(406,155)	132,147
Cash flows from financing activities			
Proceeds from the issuance of preferred stock, net	110,337	—	110,337
Proceeds from the issuance of common stock, net	43,474	—	43,474
Proceeds from the issuance of senior notes	—	300,000	(300,000)
Retirement of convertible notes	(4,915)	(232,963)	228,048
Proceeds from revolving credit facility borrowings, net	(99,000)	99,000	(198,000)
Debt issuance costs paid	(2,032)	(8,854)	6,822
Dividends paid	(5,176)	(10,316)	5,140
Other, net	—	1,148	(1,148)
Net cash provided by financing activities	42,688	148,015	(105,327)
Net increase (decrease) in cash and cash equivalents	$ 10,138	$ (113,399)	$ 123,537

Cash Flows From Operating Activities

Due primarily to the realization of higher net margins on our expanding crude oil production as well as the receipt of a federal tax refund of approximately $32 million, our cash flows from operating activities improved significantly during 2012 as compared to 2011. During 2012, we realized higher settlements from our commodity derivatives portfolio as compared to 2011 due primarily to lower natural gas prices. We paid higher amounts for interest during 2012 due to higher average outstanding debt balances and higher average interest rates. During 2011, we paid incremental transaction costs in connection with the extinguishment of the Convertible Notes, as well as costs attributable to the change in the composition of the bank syndicate in connection with our former credit facility. Restructuring and exit costs paid were higher in 2012 as compared to 2011 due primarily to the larger scale of restructuring activities during 2012, which included, among other costs, ongoing contractual payments for firm transportation capacity in the Appalachian region subsequent to our sale of assets in that region and payments to terminate the lease of our former office in Canonsburg, Pennsylvania.

Cash Flows From Investing Activities

Capital expenditures were lower during 2012 due primarily to our focus on Eagle Ford Shale drilling. During most of 2012 we operated only two rigs in this area while 2011 included up to four rigs operating in several regions. During 2011, we acquired significant acreage in the Eagle Ford Shale and had a more extensive capital program in the Mid-Continent region in the first half of the year. During 2011, we also acquired approximately $12 million of proppant chemicals that were used in our well completion activities in the latter part of 2011 and the first half of 2012.

Proceeds from sales of non-core properties and other assets were received during 2012 and 2011. The amounts received during 2012 were attributable primarily to the sale of our West Virginia, Kentucky and Virginia properties. The amounts received in 2011 were attributable primarily to the sale of our Arkoma Basin properties and a portion of our undeveloped acreage in Butler and Armstrong Counties.

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

	Year Ended December 31,	
	2012	2011
Oil and gas:		
Development drilling	$ 287,363	$ 307,779
Exploration drilling	49,462	64,075
Geological and geophysical (seismic) costs	816	11,202
Lease acquisitions	28,380	50,060
Pipeline, gathering facilities and other	18,330	12,484
	384,351	445,600
Other - Corporate	629	1,148
Total capital program costs	$ 384,980	$ 446,748

The following table reconciles the total costs of our capital expenditure program 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,	
	2012	2011
Total capital program costs	$ 384,980	$ 446,748
Less:		
Exploration expenses		
Geological and geophysical (seismic)	(816)	(11,202)
Other, primarily delay rentals	(646)	(2,183)
Transfers from tubular inventory and well materials	(13,359)	(912)
Changes in accrued capitalized costs	(4,550)	(744)
Add:		
Tubular inventory and well materials purchased in advance of drilling	4,495	11,833
Capitalized interest	803	1,983
Other	—	100
Total cash paid for capital expenditures	$ 370,907	$ 445,623

Cash Flows From Financing Activities

Cash flows from financing activities included the combined offering of preferred and common stock in 2012 which provided $153.8 million of proceeds, net of underwriting fees and issuance costs. These proceeds were used primarily to repay outstanding borrowings under the Revolver. During 2011, we issued $300 million of 2019 Senior Notes, offset substantially by the repurchase of approximately 98% of the Convertible Notes and related transaction costs. We retired the remaining Convertible Notes upon their maturity in November 2012. Both years included the payment of debt issuance costs attributable to our credit facilities and dividend payments on our common stock.

Financial Condition

As of February 15, 2013, we had $270.2 million of unused borrowing capacity available to us under the Revolver. The borrowing capacity is determined by reducing the revolving commitment of $300 million by outstanding borrowings of $28.0 million and outstanding letters of credit of $1.8 million.

Debt and Credit Facilities and Preferred Stock Financing

	As of December 31,	
	2012	2011
Revolving credit facility	$ —	$ 99,000
Senior notes due 2016, net of discount (principal amount of $300,000)	294,759	293,561
Senior notes due 2019	300,000	300,000
Convertible notes due 2012, net of discount (principal amount of $4,915)	—	4,746
	594,759	697,307
Less: Current portion of long-term debt	—	(4,746)
	$ 594,759	$ 692,561

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%). In each case, 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% to 0.500% on the undrawn portion of the Revolver depending on our ratio of outstanding borrowings to the available Revolver capacity. As of February 15, 2013, the actual interest rate on the outstanding borrowings under the Revolver was 1.75%.

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 the equity interests in the Guarantor Subsidiaries.

2016 Senior Notes. The Senior Notes due 2016, or 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 in June 2009, 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.

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.

6% Preferred Stock. The annual dividend on each share of the 6% Preferred Stock is 6.00% per annum on the liquidation preference of $10,000 per share and is payable quarterly, in arrears, on each of January 15, April 15, July 15 and October 15 of each year, commencing on January 15, 2013. We may, at our option, pay dividends in cash, common stock or a combination thereof.

Each share of the 6% Preferred Stock is convertible, at the option of the holder, into a number of shares of our common stock equal to the liquidation preference of $10,000 divided by the conversion price, which is initially $6.00 per share and is subject to specified anti-dilution adjustments. The initial conversion rate is equal to 1,666.67 shares of our common stock for each share of the 6% Preferred Stock. The initial conversion price represents a premium of 20 percent relative to the 2012 common stock offering price of $5.00 per share. The 6% Preferred Stock is not redeemable by us or the holders at any time. At any time on or after October 15, 2017, we may, at our option, cause all outstanding shares of the 6% Preferred Stock to be automatically converted into shares of our common stock at the then-applicable conversion price if the closing sale price of our common stock exceeds 130% of the then-applicable conversion price for a specified period prior to conversion. If a holder elects to convert shares of the 6% Preferred Stock upon the occurrence of certain specified fundamental changes, we may be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option value.

Asset Dispositions

As discussed previously, we completed a number of non-core asset dispositions in 2012 and 2011 to supplement the funding of our capital expenditures programs. The following table summarizes the net cash realized from these dispositions during the years ended December 31, 2012 and 2011:

	Year Ended December 31,	
Asset Description	**2012**	**2011**
Oil and gas properties	$ 96,443	$ 39,021
Tubular inventory and well materials	96	347
Other	180	100
	$ 96,719	$ 39,468

Covenant Compliance

The 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 for periods through December 31, 2013, 4.25 to 1.0 for periods through June 30, 2014 and 4.0 to 1.0 for periods through maturity in 2017. 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, 2012 and through the date upon which the 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, 2012:

Description of Covenant	**Required Covenant**	**Actual Results**
Total debt to EBITDAX	< 4.5 to 1	2.4 to 1
Current ratio	> 1.0 to 1	3.4 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 Consolidated Balance Sheets. In addition, the Revolver imposes limitations on dividends as well as limits our 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

In 2013, we anticipate making capital expenditures, excluding any additional acquisitions, of up to approximately $400 million. The capital expenditures for 2013 will be funded primarily by operating cash flows and borrowings under the Revolver. 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.

Based on expenditures to date and forecasted activity for the remainder of 2013, we expect to allocate capital expenditures as follows: Eagle Ford Shale (approximately 88 percent), Mid-Continent region (approximately four percent) and all other areas (approximately eight percent). This allocation includes approximately 86 percent for development and exploratory drilling, eight percent for leasehold acquisition and six percent for seismic and other projects. We anticipate that we will allocate substantially all of our capital expenditures to oil and NGL projects.

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, 2012, 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, 2012:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Senior Notes due 2016 [1]	$ 300,000	$ —	$ —	$ 300,000	$ —
Senior Notes due 2019 [1]	300,000	—	—	—	300,000
Interest expense [2]	250,313	52,875	105,750	59,063	32,625
Asset retirement obligations [3]	20,170	—	—	—	20,170
Derivatives [4]	1,421	—	1,421	—	—
Rental commitments [5]	8,997	2,093	3,423	2,134	1,347
Well drilling and completion	22,117	22,117	—	—	—
Firm transportation [6]	49,567	7,366	9,577	7,762	24,862
Total contractual obligations [7]	$ 952,585	$ 84,451	$ 120,171	$ 368,959	$ 379,004

[1] Upon their maturities in June 2016 and April 2019, the principal amounts of $300.0 million each will be due.
[2] Represents estimated interest payments that will be due under the 2016 Senior Notes and the 2019 Senior Notes.
[3] Represents the undiscounted balance payable in periods more than five years in the future for which $4.5 million has been recognized on the Consolidated Balance Sheet as of December 31, 2012.
[4] Represents estimated payments that we will make resulting from commodity derivatives.
[5] Relates primarily to equipment and building leases.
[6] Includes $26.9 million of undiscounted payments attributable to a firm transportation obligation for which $17.1 million has been recognized on the Consolidated Balance Sheet as of December 31, 2012.
[7] Total contractual obligations do not include anticipated 2013 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, 2012, we have recorded asset retirement obligations of $4.5 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 regulations or the adoption of new environmental laws or regulations, 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 GAAP 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, NGL 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 commodity 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, 2012, the costs attributable to unproved properties, net of accumulated amortization, were $60.7 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 with the changes recorded currently in earnings. 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

We record a valuation allowance to reduce our 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 we were to determine that we would not be able to realize all or a part of our 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 our 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, 2012, 2011 and 2010, we increased the valuation allowance for our deferred tax assets due primarily to our inability to project sufficient future taxable income in certain states.

Share-Based Compensation

In February 2012, we granted PBRSUs to certain executive officers. Vested PBRSUs are payable in cash on the third anniversary of the date of grant based upon the achievement of specified market-based performance metrics with respect to each of a one-year, two-year and three-year performance period, in each case commencing on the date of grant. The number of PBRSUs vested can range from 0% to 200% of the initial grant. The PBRSUs do not have voting rights and do not participate in dividends.

Because the PBRSUs are payable solely in cash, they are considered liability-classified awards and are included in the Other liabilities caption on our Condensed Consolidated Balance Sheets. Compensation cost associated with the PBRSUs is measured at the end of each reporting period based on the fair value derived from a Monte Carlo model and recognized based on the period of time that has elapsed during each of the individual performance periods. The Monte Carlo model is a binomial valuation model that requires significant judgment with respect to certain assumptions, including volatility, dividends and other factors. Due primarily to the sensitivity of certain model assumptions, as well as the inherent variability of modeling market-based performance over future periods, our compensation expense with respect to the PBRSUs can be volatile.

New Accounting Standards

During 2012, no new accounting standards were adopted or were pending adoption that would have a significant impact on our Consolidated Financial Statements or the 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, 2012, we had no borrowings under the Revolver.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. 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 commodity 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 oil and natural gas. We have not typically entered into derivative instruments with respect to NGLs, although we may do so in the future.

As of December 31, 2012, we reported a commodity derivative asset of $16.5 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, 2012.

In 2012, we reported net commodity derivative gains of $34.8 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 crude oil, NGL and natural gas prices. These fluctuations could be significant in a volatile pricing environment. See Note 5 to the 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, 2012:

	Instrument	Average Volume Per Day	Weighted Average Price				Fair Value			
			Floor/Swap		Ceiling		Asset		Liability	
Crude Oil:		(barrels)	($/barrel)							
First quarter 2013	Collars	1,000	$	90.00	$	100.00	$	119	$	—
Second quarter 2013	Collars	1,000	$	90.00	$	100.00		124		—
Third quarter 2013	Collars	1,000	$	90.00	$	100.00		123		—
Fourth quarter 2013	Collars	1,000	$	90.00	$	100.00		151		—
First quarter 2013	Swaps	2,250	$	103.51				2,244		—
Second quarter 2013	Swaps	2,250	$	103.51				2,040		—
Third quarter 2013	Swaps	1,500	$	102.77				1,248		—
Fourth quarter 2013	Swaps	1,500	$	102.77				1,296		—
First quarter 2014	Swaps	2,000	$	100.44				1,360		—
Second quarter 2014	Swaps	2,000	$	100.44				1,446		—
Third quarter 2014	Swaps	1,500	$	100.20				1,128		—
Fourth quarter 2014	Swaps	1,500	$	100.20				1,179		—
First quarter 2014	Swaption	812	$	100.00				—		356
Second quarter 2014	Swaption	812	$	100.00				—		355
Third quarter 2014	Swaption	812	$	100.00				—		355
Fourth quarter 2014	Swaption	812	$	100.00				—		355
Natural Gas:		(in MMBtu)	($/MMBtu)							
First quarter 2013	Collars	10,000	$	3.50		4.30		187		—
Second quarter 2013	Collars	10,000	$	3.50		4.30		219		—
Third quarter 2013	Collars	10,000	$	3.50		4.30		165		—
Fourth quarter 2013	Collars	15,000	$	3.67		4.37		216		—
First quarter 2014	Collars	5,000	$	4.00		4.50		68		—
First quarter 2013	Swaps	10,000	$	4.01				587		—
Second quarter 2013	Swaps	10,000	$	4.01				504		—
Third quarter 2013	Swaps	10,000	$	4.01				391		—
Fourth quarter 2013	Swaps	5,000	$	4.04				121		—
Settlements to be received in subsequent period								1,557		—

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 crude oil prices, natural gas 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 $10.00 per Barrel of Crude Oil or $1.00 per MMBtu of Natural Gas ($ in millions)			
	Increase		Decrease	
Effect on the fair value of crude oil derivatives	$	(19.2)	$	15.3
Effect on the fair value of natural gas derivatives	$	(5.8)	$	6.3
Effect on 2013 operating income, excluding crude oil derivatives	$	22.6	$	(22.6)
Effect on 2013 operating income, excluding natural gas derivatives	$	9.8	$	(9.8)

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, 2012 and 2011, 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, 2012. We also have audited Penn Virginia Corporation's internal control over financial reporting as of December 31, 2012, 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, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012, 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, 2012, 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 25, 2013

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2012	**2011**	**2010**
Revenues			
Crude oil	$ 229,572	$ 119,582	$ 53,532
Natural gas liquids (NGLs)	31,051	43,394	26,663
Natural gas	49,861	137,070	171,141
Gain on sales of property and equipment, net	4,282	3,570	648
Other	2,383	2,389	2,454
Total revenues	317,149	306,005	254,438
Operating expenses			
Lease operating	31,266	36,988	35,757
Gathering, processing and transportation	14,196	15,157	14,180
Production and ad valorem taxes	10,634	13,690	13,917
General and administrative	45,900	48,328	58,383
Exploration	34,092	78,943	49,641
Depreciation, depletion and amortization	206,336	162,534	134,700
Impairments	104,484	104,688	45,959
Loss on firm transportation commitment	17,332	—	—
Other	—	1,096	709
Total operating expenses	464,240	461,424	353,246
Operating loss	(147,091)	(155,419)	(98,808)
Other income (expense)			
Interest expense	(59,339)	(56,216)	(53,679)
Loss on extinguishment of debt	(3,164)	(25,421)	—
Derivatives	36,187	15,651	41,906
Other	116	335	2,403
Loss from continuing operations before income taxes	(173,291)	(221,070)	(108,178)
Income tax benefit	68,702	88,155	42,851
Loss from continuing operations	(104,589)	(132,915)	(65,327)
Income from discontinued operations, net of tax	—	—	33,448
Gain on sale of discontinued operations, net of tax	—	—	51,546
Net income (loss)	(104,589)	(132,915)	19,667
Less net income attributable to noncontrolling interests in discontinued operations	—	—	(28,090)
Loss attributable to Penn Virginia Corporation	(104,589)	(132,915)	(8,423)
Preferred stock dividends	(1,687)	—	—
Loss attributable to common shareholders	$ (106,276)	$ (132,915)	$ (8,423)
Loss per share - Basic:			
Continuing operations	$ (2.22)	$ (2.90)	$ (1.44)
Discontinued operations	—	—	0.12
Gain on sale of discontinued operations	—	—	1.13
Net loss	$ (2.22)	$ (2.90)	$ (0.19)
Loss per share - Diluted:			
Continuing operations	$ (2.22)	$ (2.90)	$ (1.44)
Discontinued operations	—	—	0.12
Gain on sale of discontinued operations	—	—	1.13
Net loss	$ (2.22)	$ (2.90)	$ (0.19)
Weighted average shares outstanding - basic	47,919	45,784	45,553
Weighted average shares outstanding - diluted	47,919	45,784	45,553

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31,		
	2012	**2011**	**2010**
Net income (loss)	$ (104,589)	$ (132,915)	$ 19,667
Other comprehensive income (loss):			
Hedging reclassification adjustments	—	—	582
Total change in hedging derivative financial instruments	—	—	582
Change in pension and postretirement obligations, net of tax of $54 in 2012, ($79) in 2011 and $188 in 2010	102	(146)	348
	102	(146)	930
Comprehensive income (loss)	(104,487)	(133,061)	20,597
Less amounts attributable to noncontrolling interests:			
Net income	—	—	(28,090)
Other comprehensive income	—	—	(582)
Comprehensive loss attributable to Penn Virginia	$ (104,487)	$ (133,061)	$ (8,075)

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	As of December 31,	
	2012	**2011**
Assets		
Current assets		
Cash and cash equivalents	$ 17,650	$ 7,512
Accounts receivable, net of allowance for doubtful accounts	62,978	72,432
Derivative assets	11,292	18,987
Income taxes receivable	—	31,465
Other current assets	4,595	14,950
Total current assets	96,515	145,346
Property and equipment, net (successful efforts method)	1,723,359	1,777,575
Derivative assets	5,181	—
Other assets	17,934	20,132
Total assets	$ 1,842,989	$ 1,943,053
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 111,655	$ 94,504
Derivative liabilities	—	3,549
Deferred income taxes	370	3,808
Current portion of long-term debt	—	4,746
Total current liabilities	112,025	106,607
Other liabilities	28,901	15,887
Derivative liabilities	1,421	6,850
Deferred income taxes	210,767	274,839
Long-term debt	594,759	692,561
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock of $100 par value – 100,000 shares authorized; shares issued of 11,500 as of December 31, 2012 and none as of December 31, 2011	1,150	—
Common stock of $0.01 par value – 128,000,000 shares authorized; shares issued of 55,117,346 and 45,714,191 as of December 31, 2012 and December 31, 2011, respectively	364	270
Paid-in capital	849,046	690,131
Retained earnings	45,790	157,242
Deferred compensation obligation	3,111	3,620
Accumulated other comprehensive loss	(982)	(1,084)
Treasury stock – 218,320 and 223,886 shares of common stock, at cost, as of December 31, 2012 and December 31, 2011, respectively	(3,363)	(3,870)
Total shareholders' equity	895,116	846,309
Total liabilities and shareholders' equity	$ 1,842,989	$ 1,943,053

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2012	2011	2010
Cash flows from operating activities			
Net income (loss)	$ (104,589)	$ (132,915)	$ 19,667
Adjustments to reconcile net income (loss) to net cash provided by operating activities from continuing operations:			
Income from discontinued operations	—	—	(36,832)
Gain on sale of discontinued operations	—	—	(86,662)
Non-cash portion of loss on extinguishment of debt	3,144	22,456	—
Loss on firm transportation commitment	17,332	—	—
Depreciation, depletion and amortization	206,336	162,534	134,700
Impairments	104,484	104,688	45,959
Derivative contracts:			
Net gains	(36,187)	(15,651)	(41,906)
Cash settlements	29,723	27,380	32,818
Deferred income taxes (benefit)	(68,676)	(85,501)	42,528
(Gain) loss on sales of assets, net	(4,282)	(2,474)	61
Non-cash exploration expense	32,634	60,940	36,275
Non-cash interest expense	4,062	6,807	11,984
Share-based compensation (equity-classified)	6,347	7,430	7,811
Other, net	1,004	275	(209)
Changes in operating assets and liabilities:			
Accounts receivable, net	9,907	(1,792)	(19,964)
Income taxes receivable and payable, net	31,439	(2,815)	2,627
Accounts payable and accrued expenses	9,710	(6,552)	10,877
Other assets and liabilities	(930)	(69)	(79,895)
Net cash provided by operating activities from continuing operations	241,458	144,741	79,839
Cash flows from investing activities			
Capital expenditures - property and equipment	(370,907)	(445,623)	(405,994)
Proceeds from the sale of PVG units, net (Note 3)	—	—	139,120
Proceeds from sales of assets, net	96,719	39,368	25,567
Other, net	180	100	1,192
Net cash used in investing activities for continuing operations	(274,008)	(406,155)	(240,115)
Cash flows from financing activities			
Proceeds from the issuance of preferred stock, net	110,337	—	—
Proceeds from the issuance of common stock, net	43,474	—	—
Proceeds from the issuance of senior notes	—	300,000	—
Retirement of convertible notes	(4,915)	(232,963)	—
Proceeds from revolving credit facility borrowings	211,000	114,000	—
Repayment of revolving credit facility borrowings	(310,000)	(15,000)	—
Debt issuance costs paid	(2,032)	(8,854)	—
Dividends paid	(5,176)	(10,316)	(10,271)
Proceeds from the sale of PVG units, net (Note 3)	—	—	199,125
Distributions received from discontinued operations	—	—	11,218
Other, net	—	1,148	2,098
Net cash provided by financing activities from continuing operations	42,688	148,015	202,170
Cash flows from discontinued operations			
Net cash provided by operating activities	—	—	77,759
Net cash used in investing activities	—	—	(18,112)
Net cash used in provided by financing activities	—	—	(59,647)
Net cash provided by discontinued operations	—	—	—
Net increase (decrease) in cash and cash equivalents	10,138	(113,399)	41,894
Cash and cash equivalents - beginning of period	7,512	120,911	79,017
Cash and cash equivalents - end of period	$ 17,650	$ 7,512	$ 120,911
Supplemental disclosures:			
Cash paid for:			
Interest (net of amounts capitalized)	$ 54,808	$ 44,589	$ 43,531
Income taxes (net of refunds received)	$ (32,603)	$ 210	$ 28,184

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Shares Outstanding	Preferred Stock	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, 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	—	—	—	—	—	—	—	—	—	(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
Net loss	—	—	—	—	(104,589)	—	—	—	(104,589)	—	(104,589)
Change in pension and postretirement obligations	—	—	—	—	—	—	102	—	102	—	102
Dividends paid ($0.1125 per common share)	—	—	—	—	(5,176)	—	—	—	(5,176)	—	(5,176)
Dividends declared ($146.67 per preferred share)	—	—	—	—	(1,687)	—	—	—	(1,687)	—	(1,687)
Issuance of preferred stock	—	1,150	—	109,312	—	—	—	—	110,462	—	110,462
Issuance of common stock	9,200	—	92	43,258	—	—	—	—	43,350	—	43,350
Common stock issued as compensation	80	—	1	424	—	—	—	—	425	—	425
Share-based compensation	—	—	—	5,765	—	—	—	—	5,765	—	5,765
Deferred compensation	35	—	—	157	—	(509)	—	507	155	—	155
Restricted stock unit vesting	88	—	1	(1)	—	—	—	—	—	—	—
Balance as of December 31, 2012	55,117	$ 1,150	$ 364	$ 849,046	$ 45,790	$ 3,111	$ (982)	$ (3,363)	$ 895,116	$ —	$ 895,116

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in thousands, except per share amounts)

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company engaged primarily in the exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas in various domestic onshore regions of the United States including Texas, the Mid-Continent, Mississippi and to a lesser extent, the Marcellus Shale in Appalachia.

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. Such estimates include certain asset and liability valuations as further described in these notes. 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 commodity price and interest rate 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 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. 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 our 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 crude oil and natural gas 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.

Depreciation, depletion and amortization ("DD&A") of proved producing properties is computed using the units-of-production method. Natural gas is converted to a liquids equivalent on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of liquids. Historically, we have adjusted our depletion rate throughout the year as new data becomes available and in the fourth quarter based on our 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, intent to develop properties 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 unproved reserves, future commodity prices and the timing of future production and capital expenditures, and intent to develop properties, among others. We have recognized impairments of our properties in 2012, 2011 and 2010, 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.

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 at each reporting period 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 crude oil, NGLs and natural gas 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 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

Our stock compensation plans permit the grant of incentive and nonqualified stock options, common stock, deferred common stock units, restricted stock and restricted stock units to our employees and directors. We measure the cost of employee services received in exchange for an award of equity-classified instruments based on the grant-date fair value of the award. Compensation cost associated with the liability-classified awards is measured at the end of each reporting period and recognized based on the period of time that has elapsed during the applicable performance period.

Recent Accounting Standards

During 2012, no new accounting standards were adopted or were pending adoption that would have a significant impact on our Consolidated Financial Statements or the Notes to Consolidated Financial Statements.

Reclassifications

Certain amounts for the 2011 and 2010 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 our Consolidated Financial Statements were issued, and concluded that no subsequent events have occurred that would require recognition in our Consolidated Financial Statements or disclosure in the Notes to Consolidated Financial Statements.

3. Acquisitions and Divestitures

In the following paragraphs, all references to crude oil and natural gas reserves and acreage acquired or sold 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 Property Acquisitions

In December 2011, we entered into an agreement with an industry partner to jointly explore a 13,500 acre area of mutual interest ("AMI") in Lavaca County, Texas. Under the terms of the agreement, we were required to commence drilling on six wells by September 1, 2012, as well as carry our partner for its working interest share of the costs of the first three wells, to earn our entire interest in the acreage. We fulfilled this requirement during the third quarter of 2012 and, as a result, earned an approximately 60 percent interest in this acreage.

In December 2012, this industry partner in the Lavaca County Eagle Ford Shale acreage elected to not participate in the last 17 initial unit wells to be drilled on this acreage. Upon the drilling of each of the initial unit wells, our industry partner will have no participatory rights in any subsequent wells drilled in such unit. We are presently seeking a partner to acquire a 40 percent working interest in this acreage in which our industry partner has elected not to participate.

In addition to the acreage earned in Lavaca County, as discussed above, we acquired approximately 4,100 net acres in the Eagle Ford Shale in Gonzales and Lavaca Counties, Texas in 2012 for approximately $10 million increasing our net Eagle Ford Shale acreage position to approximately 32,500 net acres. During 2011 and 2010, we acquired acreage in Gonzales County for approximately $27 million and $31 million, respectively. We are the operator of all of our Gonzales County acreage with an average working interest of approximately 84 percent.

Divestitures

Oil and Gas Properties

In July 2012, we sold substantially all of our legacy natural gas assets in West Virginia, Kentucky and Virginia for approximately $100 million, excluding transaction costs and before customary purchase and sale adjustments. Through December 31, 2012, we received proceeds of $95.7 million, net of transaction costs and customary closing adjustments, and recognized a gain of $3.3 million in connection with the transaction. The assets sold included vertical and horizontal coalbed methane and vertical conventional properties, a gathering system and royalty interests. These assets had net production of approximately 20 million cubic feet of natural gas equivalent per day (3,333 barrels of oil equivalent) and estimated proved reserves of approximately 106 billion cubic feet of natural gas equivalent (17.7 million barrels of oil equivalent), of which 96 percent was proved developed and almost 100 percent was natural gas. An impairment charge of $28.6 million was recognized in the second quarter of 2012 with respect to these assets.

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 August 2011, we sold a substantial portion of our Arkoma Basin assets for approximately $30 million, excluding transaction costs and 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 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.

In January 2010, we completed the sale of all of our assets 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 2012, 2011 and 2010, we also received net proceeds of $1.6 million, $1.2 million and $2.0 million, respectively, from the sale of various non-core oil and gas properties located in various states both within and outside of our present operating regions.

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

In a series of transactions that occurred during 2009 and 2010, we sold common units of PVG ("PVG Common Units") owned by us resulting in a reduction of our limited partner interest in PVG to 22.6 percent. 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, we contributed our 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 period. Additional information with respect to discontinued operations is provided in Note 19.

4. Accounts Receivable and Major Customers

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

	As of December 31,	
	2012	2011
Customers	$ 43,967	$ 49,763
Joint interest partners	16,154	22,755
Other	4,523	1,695
	64,644	74,213
Less: Allowance for doubtful accounts	(1,666)	(1,781)
	$ 62,978	$ 72,432

For the year ended December 31, 2012, four customers accounted for $182.0 million, or approximately 59% of our consolidated product revenues. The revenues generated from these customers during 2012 were $60.1 million, $46.7 million, $41.5 million and $33.8 million or 19%, 15%, 14% and 11% of the consolidated total, respectively. As of December 31, 2012, $21.6 million, or approximately 34% of our consolidated accounts receivable, including joint interest billings, related to these customers. For the year ended December 31, 2011, three customers accounted for $120.4 million, or approximately 40% of our consolidated product revenues. The revenues generated from these customers during 2011 were $51.7 million, $34.6 million and $34.1 million, or approximately 17%, 12% and 11% of the consolidated total, respectively. As of December 31, 2011, $17.2 million, or approximately 24% 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 any of these customers.

5. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to crude oil and natural gas 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 formally 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.

The following table sets forth our commodity derivative positions as of December 31, 2012:

	Instrument	Average Volume Per Day	Weighted Average Price Floor/Swap	Weighted Average Price Ceiling	Fair Value Asset	Fair Value Liability
Crude Oil:		**(barrels)**	**($/barrel)**			
First quarter 2013	Collars	1,000	$ 90.00	$ 100.00	$ 119	$ —
Second quarter 2013	Collars	1,000	$ 90.00	$ 100.00	124	—
Third quarter 2013	Collars	1,000	$ 90.00	$ 100.00	123	—
Fourth quarter 2013	Collars	1,000	$ 90.00	$ 100.00	151	—
First quarter 2013	Swaps	2,250	$ 103.51		2,244	—
Second quarter 2013	Swaps	2,250	$ 103.51		2,040	—
Third quarter 2013	Swaps	1,500	$ 102.77		1,248	—
Fourth quarter 2013	Swaps	1,500	$ 102.77		1,296	—
First quarter 2014	Swaps	2,000	$ 100.44		1,360	—
Second quarter 2014	Swaps	2,000	$ 100.44		1,446	—
Third quarter 2014	Swaps	1,500	$ 100.20		1,128	—
Fourth quarter 2014	Swaps	1,500	$ 100.20		1,179	—
First quarter 2014	Swaption	812	$ 100.00		—	356
Second quarter 2014	Swaption	812	$ 100.00		—	355
Third quarter 2014	Swaption	812	$ 100.00		—	355
Fourth quarter 2014	Swaption	812	$ 100.00		—	355
Natural Gas:		**(in MMBtu)**	**($/MMBtu)**			
First quarter 2013	Collars	10,000	$ 3.50	$ 4.30	187	—
Second quarter 2013	Collars	10,000	$ 3.50	$ 4.30	219	—
Third quarter 2013	Collars	10,000	$ 3.50	$ 4.30	165	—
Fourth quarter 2013	Collars	15,000	$ 3.67	$ 4.37	216	—
First quarter 2014	Collars	5,000	$ 4.00	$ 4.50	68	—
First quarter 2013	Swaps	10,000	$ 4.01		587	—
Second quarter 2013	Swaps	10,000	$ 4.01		504	—
Third quarter 2013	Swaps	10,000	$ 4.01		391	—
Fourth quarter 2013	Swaps	5,000	$ 4.04		121	—
Settlements to be received in subsequent period					1,557	—

Interest Rate Swaps

In February 2012, we entered into an interest rate swap agreement to establish variable interest rates on approximately one-third of the outstanding obligation under our 7.25% Senior Notes due 2019 (the “2019 Senior Notes”). In May 2012, we terminated this agreement and received $1.2 million in cash proceeds.

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 our 10.375% Senior Notes due 2016 (the “2016 Senior Notes”). In August 2011, we terminated this agreement and received $2.9 million in cash proceeds.

As of December 31, 2012, we had no interest rate derivative instruments outstanding.

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,		
	2012	2011	2010
Impact by contract type:			
Commodity contracts	$ 34,781	$ 14,422	$ 36,693
Interest rate contracts	1,406	1,229	5,213
	$ 36,187	$ 15,651	$ 41,906
Realized and unrealized impact:			
Cash received (paid) for:			
Commodity contract settlements	$ 28,317	$ 23,562	$ 33,480
Interest rate contract settlements	1,406	3,818	(662)
	29,723	27,380	32,818
Unrealized gains (losses) attributable to:			
Commodity contracts	6,464	(9,140)	3,213
Interest rate contracts	—	(2,589)	5,875
	6,464	(11,729)	9,088
	$ 36,187	$ 15,651	$ 41,906

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.

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, 2012		December 31, 2011	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Commodity contracts	Derivative assets/liabilities - current	$ 11,292	$ —	$ 18,987	$ 3,549
Interest rate contracts	Derivative assets/liabilities - current	—	—	—	—
		11,292	—	18,987	3,549
Commodity contracts	Derivative assets/liabilities - noncurrent	5,181	1,421	—	6,850
Interest rate contracts	Derivative assets/liabilities - noncurrent	—	—	—	—
		5,181	1,421	—	6,850
		$ 16,473	$ 1,421	$ 18,987	$ 10,399

As of December 31, 2012, we reported a commodity derivative asset of $16.5 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 have not received any cash collateral from our counterparties with respect to our derivative asset 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, 2012	As of December 31, 2011
Oil and gas properties:		
Proved	$ 2,277,811	$ 2,239,186
Unproved	60,746	120,288
Total oil and gas properties	2,338,557	2,359,474
Other property and equipment	93,648	143,285
Total property and equipment	2,432,205	2,502,759
Accumulated depreciation, depletion and amortization	(708,846)	(725,184)
	$ 1,723,359	$ 1,777,575

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

	2012		2011		2010	
	Number of Wells	Cost	Number of Wells	Cost	Number of Wells	Cost
Balance at beginning of year	—	$ —	1	$ 6,180	—	$ —
Additions pending determination of proved reserves	1	4,435	—	—	1	6,180
Reclassification to wells, equipment and facilities based on the determination of proved reserves	—	—	—	—	—	—
Charged to exploration expense	—	—	(1)	(6,180)	—	—
Balance at end of year	1	$ 4,435	—	$ —	1	$ 6,180

7. Asset Retirement Obligations

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

	As of December 31, 2012	As of December 31, 2011
Balance at beginning of year	$ 6,283	$ 7,364
Liabilities incurred	57	214
Liabilities settled	(236)	(183)
Sale of properties	(1,976)	(1,611)
Accretion expense	385	499
Balance at end of year	$ 4,513	$ 6,283

8. Long-Term Debt

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

	As of December 31, 2012	As of December 31, 2011
Revolving credit facility	$ —	$ 99,000
Senior notes due 2016, net of discount (principal amount of $300,000)	294,759	293,561
Senior notes due 2019	300,000	300,000
Convertible notes due 2012, net of discount (principal amount of $4,915)	—	4,746
	594,759	697,307
Less: Current portion of long-term debt	—	(4,746)
	$ 594,759	$ 692,561

Revolving Credit Facility

In September 2012, we entered into the Revolver, which replaced our previous revolving credit facility that was entered into in August 2011. The Revolver provides for a $300 million revolving commitment and an accordion feature that allows us to increase the commitment by up to an aggregate of $300 million upon receiving additional commitments from one or more lenders. The Revolver also includes a $20 million sublimit for the issuance of letters of credit. The Revolver is governed by a borrowing base calculation, and the availability under the Revolver may not exceed the lesser of the aggregate commitments and the borrowing base. The initial borrowing base under the Revolver is $300 million and will be redetermined based on a semi-annual review of our total proved oil, NGL and natural gas reserves starting in the spring of 2013. The Revolver is available to us for general purposes including working capital, capital expenditures and acquisitions. The Revolver matures in September 2017. We had letters of credit of $2.1 million outstanding as of December 31, 2012. As of December 31, 2012, our available borrowing capacity under the Revolver, as reduced by outstanding borrowings and letters of credit, was $297.9 million.

In September 2012, we capitalized $2.0 million of debt issuance costs in connection with the Revolver, which will be amortized as a component of interest expense over the five year term. Capitalized debt issuance costs attributable to the previous revolving credit facility of $3.2 million were expensed as a loss on the extinguishment of debt.

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 ("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% to 0.500% on the undrawn portion of the Revolver depending on our ratio of outstanding borrowings to the available Revolver capacity.

The Revolver is guaranteed by Penn Virginia and all of our material subsidiaries (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.

The guarantees provided by the parent company and 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.

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 through December 31, 2013, 4.25 to 1.0 through June 30, 2014 and then 4.0 to 1.0 through maturity.

2016 Senior Notes

The 2016 Senior Notes were originally sold at 97% of par in June 2009, 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 starting 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 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 starting 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

In connection with a tender offer completed in April 2011, the Company repurchased $225.1 million aggregate principal amount of the 4.50% Convertible Senior Subordinated Notes due 2012 (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 2011, of which $24.2 million was charged to earnings and the remaining $1.7 million was charged directly to shareholders' equity. The remaining Convertible Notes were retired upon their maturity in November 2012.

Debt Maturities

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

Year		Amounts
2013	$	—
2014		—
2015		—
2016		300,000
2017		—
Thereafter		300,000
Total	$	600,000

9. Income Taxes

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

	Year Ended December 31,					
		2012		2011		2010
Current income taxes (benefit)						
Federal	$	—	$	1,279	$	(109,240)
State		(26)		(3,933)		876
		(26)		(2,654)		(108,364)
Deferred income taxes (benefit)						
Federal		(60,676)		(80,529)		67,999
State		(8,000)		(4,972)		(2,486)
		(68,676)		(85,501)		65,513
	$	(68,702)	$	(88,155)	$	(42,851)

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

	Year Ended December 31,					
		2012		2011		2010
Continuing operations	$	(68,702)	$	(88,155)	$	(42,851)
Discontinued operations		—		—		3,384
Gain on sale of discontinued operations		—		—		35,116
	$	(68,702)	$	(88,155)	$	(4,351)

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,					
	2012		2011		2010	
Computed at federal statutory rate	$ (60,652)	(35.0)%	$ (77,374)	(35.0)%	$ (37,862)	(35.0)%
State income taxes, net of federal income tax benefit	(8,026)	(4.6)%	(4,825)	(2.2)%	(1,927)	(1.8)%
Other, net	(24)	— %	(5,956)	(2.7)%	(3,062)	(2.8)%
	$ (68,702)	(39.6)%	$ (88,155)	(39.9)%	$ (42,851)	(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,	
	2012	2011
Deferred tax liabilities:		
Property and equipment	$ 311,002	$ 429,568
Fair value of derivative instruments	5,268	3,006
Convertible notes	—	60
Total deferred tax liabilities	316,270	432,634
Deferred tax assets:		
Pension and postretirement benefits	2,864	3,046
Share-based compensation	10,760	8,838
Net operating loss ("NOL") carryforwards	102,407	150,953
Other	15,788	10,642
	131,819	173,479
Less: Valuation allowance	(26,686)	(19,492)
Total deferred tax assets	105,133	153,987
Net deferred tax liability	$ 211,137	$ 278,647

As of December 31, 2012, we had federal NOL carryforwards of approximately $203.8 million, which expire starting in 2031, and state NOL carryforwards of approximately $47.8 million, which expire between 2024 and 2032. As of December 31, 2012 and 2011, valuation allowances of $41.0 million and $30.0 million, respectively, had been recorded for deferred tax assets associated with state NOL carryforwards that were not more-likely-than-not to be realized.

As of December 31, 2011, we classified $31.2 million of deferred tax assets as a current income tax receivable attributable to the federal NOL expected to be utilized. In 2012, we received a federal tax refund of approximately $32 million from the carryback of the 2011 federal NOL, and the remainder of the NOL is available for carryforward.

We have no liability for unrecognized tax benefits as of December 31, 2012 and 2011. There were no interest and penalty charges recognized during the years ended December 31, 2012 , 2011 and 2010. Tax years from 2009 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,	
	2012	2011
Other current assets:		
Tubular inventory and well materials	$ 4,033	$ 14,251
Prepaid expenses	562	699
	$ 4,595	$ 14,950
Other assets:		
Debt issuance costs	$ 13,186	$ 16,993
Assets of supplemental employee retirement plan ("SERP") [1]	3,237	3,088
Other	1,511	51
	$ 17,934	$ 20,132
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 37,835	$ 30,186
Drilling costs	37,703	30,948
Royalties	14,390	15,235
Production and franchise taxes	2,874	3,495
Compensation - related [2, 3]	6,853	5,186
Interest	5,828	5,964
Preferred stock dividends	1,687	—
Other	4,485	3,490
	$ 111,655	$ 94,504
Other liabilities:		
Firm transportation obligation	$ 14,333	$ —
Asset retirement obligations	4,513	6,283
Defined benefit pension obligations [2]	1,821	1,763
Postretirement health care benefit obligations [2]	2,634	3,022
Deferred compensation - SERP obligation and other [1]	3,310	3,172
Other	2,290	1,647
	$ 28,901	$ 15,887

[1] Represents the assets and liabilities of our nonqualified supplemental employee retirement savings plan. Assets of the plan are held in a Rabbi Trust. Shares of our common stock held by the Rabbi Trust are presented as treasury stock carried at cost.

[2] Includes the combined unfunded benefit obligations under our defined benefit pension and postretirement health care plans of $5.1 million and $5.4 million as of December 31, 2012 and 2011. The expense recognized with respect to these plans was $0.3 million, $0.4 million and $0.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.

[3] Includes employer matching obligations under our defined contribution retirement plan of $0.2 million and $0.3 million as of December 31, 2012 and 2011, respectively. The expense recognized with respect to this plan was $0.9 million, $1.2 million and $1.7 million for the years ended December 31, 2012, 2011 and 2010, 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 upon the sale of an asset or that we would expect to 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, 2012, 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, 2012		December 31, 2011	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Notes due 2016	$ 316,500	$ 294,759	$ 319,500	$ 293,561
Senior Notes due 2019	286,500	300,000	280,500	300,000
Convertible Notes	—	—	4,925	4,746
	$ 603,000	$ 594,759	$ 604,925	$ 598,307

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, 2012			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets - current	$ 11,292	$ —	$ 11,292	$ —
Commodity derivative assets - noncurrent	5,181	—	5,181	—
Assets of SERP	3,237	3,237	—	—
Liabilities:				
Commodity derivative liabilities - current	—	—	—	—
Commodity derivative liabilities - noncurrent	(1,421)	—	(1,421)	—
Deferred compensation - SERP obligation and other	(3,305)	(3,305)	—	—

	As of December 31, 2011			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets - current	$ 18,987	$ —	$ 18,987	$ —
Assets of SERP	3,088	3,088	—	—
Liabilities:				
Commodity derivative liabilities - current	(3,549)	—	(3,549)	—
Commodity derivative liabilities - noncurrent	(6,850)	—	(6,850)	—
Deferred compensation - SERP obligation and other	(3,168)	(3,168)	—	—

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one level of the fair value hierarchy to another level. In such instances, the transfer is deemed to have occurred at the beginning of the quarterly period in which the event or change in circumstances that caused the transfer occurred. There were no transfers during the years ended December 31, 2012, 2011 and 2010.

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 commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for West Texas Intermediate crude oil and NYMEX Henry Hub gas 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.
- *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.
- *Assets of SERP*: 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 - SERP obligations and other*: 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, indicative sales prices for properties, 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 the 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, 2012, by category, for the next five years and thereafter:

Year	Minimum Rentals	Drilling and Completion	Firm Transportation
2013	$ 2,093	$ 22,117	$ 4,580
2014	1,810	—	2,002
2015	1,613	—	2,002
2016	1,481	—	1,095
2017	653	—	1,095
Thereafter	1,347	—	11,862
Total	$ 8,997	$ 22,117	$ 22,636

Rental Commitments

Operating lease rental expense in the years ended December 31, 2012, 2011 and 2010 was $11.0 million, $11.4 million and $14.8 million, respectively, related primarily to field equipment, office equipment and office leases.

Drilling and Completion Commitments

We have agreements to purchase oil and gas well drilling and well completion services from third parties with original terms of up to 3 years. As of December 31, 2012, there were no well drilling or well completion agreements with terms that extended beyond June 30, 2013. The well drilling 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, 2012, the penalty amount would have been $2.0 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 1 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, 2012. 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, 2012, we have recorded AROs of $4.5 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

Preferred Stock

In October 2012, we completed a registered offering of 11,500 shares of our 6% Series A Convertible Perpetual Preferred Stock (the "6% Preferred Stock") that provided $110.3 million of proceeds, net of underwriting fees and issuance costs.

The annual dividend on each share of the 6% Preferred Stock is 6.00% per annum on the liquidation preference of $10,000 per share and is payable quarterly, in arrears, on each of January 15, April 15, July 15 and October 15 of each year, commencing on January 15, 2013. We may, at our option, pay dividends in cash, common stock or a combination thereof. On December 20, 2012, the Company's board of directors declared a quarterly cash dividend of $146.67 per share, which reflects the pro rata portion of the regular quarterly cash dividend representing the period from the original issue date of October 17, 2012 through January 14, 2013. An obligation for $1.7 million representing this declared dividend is included in the Accounts payable and accrued liabilities caption on our Consolidated Balance Sheets as of December 31, 2012.

Each share of the 6% Preferred Stock is convertible, at the option of the holder, into a number of shares of our common stock equal to the liquidation preference of $10,000 divided by the conversion price, which is initially $6.00 per share and is subject to specified anti-dilution adjustments. The initial conversion rate is equal to 1,666.67 shares of our common stock for each share of the 6% Preferred Stock. The initial conversion price represents a premium of 20 percent relative to the 2012 common stock offering price of $5.00 per share. The 6% Preferred Stock is not redeemable by us or the holders at any time. At any time on or after October 15, 2017, we may, at our option, cause all outstanding shares of the 6% Preferred Stock to be automatically converted into shares of our common stock at the then-applicable conversion price if the closing sale price of our common stock exceeds 130% of the then-applicable conversion price for a specified period prior to conversion. If a holder elects to convert shares of the 6% Preferred Stock upon the occurrence of certain specified fundamental changes, we may be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option value.

Common Stock

Concurrent with the 6% Preferred Stock offering, we completed a registered offering of 9.2 million shares of our common stock that provided $43.5 million of proceeds, net of underwriting fees and issuance costs. The proceeds from the combined offerings were used to repay outstanding borrowings under the Revolver and for general corporate purposes.

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.

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 $1.0 million, $1.1 million and $0.9 million as of December 31, 2012, 2011 and 2010, 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 our 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 218,320 and 223,886 shares have been recorded as treasury stock as of December 31, 2012 and 2011, 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.

14. Share-Based Compensation

Our stock compensation plans (collectively, the "Stock Compensation Plans") permit the grant of incentive and nonqualified stock options, common stock, deferred common stock units, restricted stock and restricted stock units to our employees and directors. As of December 31, 2012, there were approximately 2,317,176 and 88,119 shares available for issuance to employees and directors, respectively, pursuant to the Stock Compensation Plans.

With the exception of performance-based restricted stock units ("PBRSUs"), all of the awards issued under our Stock Compensation Plans are classified as equity instruments because they result in the issuance of common stock on the date of grant, upon exercise or are otherwise payable in common stock upon vesting, as applicable. The compensation cost attributable to these awards is measured at the grant date and recognized over the applicable vesting period as a non-cash item of expense. Because the PBRSUs are payable in cash, they are considered liability-classified awards and are included in the Other liabilities caption on our Consolidated Balance Sheets. Compensation cost associated with the PBRSUs is measured at the end of each reporting period and recognized based on the period of time that has elapsed during each of the individual performance periods.

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

	Year Ended December 31,		
	2012	2011	2010
Equity-classified awards:			
Stock option awards	$ 4,424	$ 5,477	$ 5,828
Common, deferred, restricted and restricted unit awards	1,923	1,953	1,983
	6,347	$ 7,430	$ 7,811
Liability-classified awards	714	—	—
	$ 7,061	$ 7,430	$ 7,811

Stock Options

The exercise price of all stock 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 us, 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 10 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 historically issued new shares to satisfy stock 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.

	2012	2011	2010
Expected volatility	67.3% to 72.9%	61.7% to 71.9%	59.5% to 67.6%
Dividend yield	2.25% to 4.98%	1.25% to 2.25%	0.90% to 1.20%
Expected life	3.5 to 4.6 years	3.5 to 4.6 years	3.5 to 4.6 years
Risk-free interest rate	0.36% to 0.51%	0.39% to 2.18%	0.68% to 2.30%

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

	Shares Under Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at beginning of year	2,475,074	$ 22.84		
Granted	224,501	5.59		
Exercised	—	—		
Forfeited	(412,841)	22.99		
Outstanding at end of year	2,286,734	$ 21.14	6.6	$ 7
Exercisable at end of year	1,711,098	$ 23.21	6.1	$ —

The weighted-average grant-date fair value of options granted during the years ended December 31, 2012, 2011 and 2010 was $2.54, $7.30 and $10.13 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 2012.

As of December 31, 2012, we had $2.6 million of unrecognized compensation cost related to unvested stock options. We expect that cost to be recognized over a weighted-average period of 0.5 years. The total grant-date fair values of stock options that vested in 2012, 2011 and 2010 were $4.7 million, $3.7 million and $4.6 million, respectively.

Common Stock

A portion of the compensation paid to certain non-employee members of our board of directors is paid in common stock. Each share of common stock granted as compensation vests immediately upon issuance. In 2012, we granted 79,700 shares of common stock to our non-employee directors at a weighted-average grant date fair value of $5.33 per share.

Deferred Common Stock Units

A portion of the compensation paid to certain 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	208,783	$ 17.34
Granted	29,295	5.38
Converted	(35,202)	18.95
Balance at end of year	202,876	$ 15.33

As of December 31, 2012, 2011 and 2010, shareholders' equity included deferred compensation obligations of $3.1 million, $3.6 million and $2.7 million, respectively, and corresponding amounts for treasury stock.

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 us. 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 total grant-date fair values of restricted stock that vested in 2011 and 2010 were $0.3 million and $0.5 million. There were no unvested restricted stock awards outstanding during 2012, and no restricted stock awards vested during 2012.

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 us. 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]	99,826	$ 18.10
Granted	108,157	5.67
Vested	(105,773)	13.09
Forfeited	(10,239)	9.20
Balance at end of year [1]	91,971	$ 10.08

[1] Excludes 61,344 units at the beginning of the year and 78,864 units at the 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, 2012, we had $0.6 million of unrecognized compensation cost attributable to unvested 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 2012, 2011 and 2010 were $1.4 million, $0.9 million and $0.9 million, respectively.

Performance-Based Restricted Stock Units

In February 2012, we granted PBRSUs to certain executive officers. Vested PBRSUs are payable in cash on the third anniversary of the date of grant based upon the achievement of specified market-based performance metrics with respect to each of a one-year, two-year and three-year performance period, in each case commencing on the date of grant. The number of PBRSUs vested can range from 0% to 200% of the initial grant. The PBRSUs do not have voting rights and do not participate in dividends.

If the grantee's employment terminates for any reason prior to the third anniversary of the grant date, then the grantee's PBRSUs will be forfeited and no cash will be payable with respect to any PBRSUs. If the grantee is or becomes retirement eligible, which is defined as reaching age 62 and completing 10 years of consecutive service with us or our affiliate, and his or her employment terminates for any reason other than cause prior to the third anniversary of the grant date, then all of the grantee's PBRSUs will vest and become payable in the amount and at the time the PBRSUs would have otherwise vested and been payable. If the grantee dies or becomes disabled prior to the third anniversary of the grant date, a pro-rated share (based on the number of days employed during the three-year vesting period) of the PBRSUs will vest and the grantee will be paid for such PBRSUs at the target percentage at the end of the end of the original three-year vesting period. In the event of a change in control of us, all of the grantee's PBRSUs will immediately vest and the grantee will be paid for such PBRSUs following the change in control at the target percentage (regardless of our actual market-based performance) and using the value of our common stock on the effective date of the change in control (calculated as the closing price of our common stock on the effective date of the change in control).

The compensation cost of the PBRSUs is based on the fair value derived from a Monte Carlo model. The Monte Carlo model is a binomial valuation model that utilizes certain assumptions, including expected volatility, dividend yield, risk-free interest rates and a measure of total shareholder return. The ranges for the assumptions used in the Monte Carlo model for the PBRSUs granted in 2012 are as follows:

Expected volatility	29.3% to 78.0%
Dividend yield	0.00% to 5.30%
Risk-free interest rate	0.02% to 0.43%

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

	Performance-Based Restricted Stock Units	Weighted-Average Fair Value
Balance at beginning of year	—	$ —
Granted	216,441	6.80
Forfeited	(15,617)	12.80
Balance at end of year	200,824	$ 6.67

As of December 31, 2012, $0.7 million, which represents the fair value of the outstanding PBRSUs, is included in the Other liabilities caption on our Consolidated Balance Sheets.

15. Restructuring Activities

During 2012, we completed an organizational restructuring in conjunction with the sale of our legacy natural gas assets in West Virginia, Kentucky and Virginia. We terminated approximately 30 employees and closed our regional office in Canonsburg, Pennsylvania. We recorded a charge in connection with the early termination of the lease of that office. In addition, we have a contractual commitment for certain firm transportation capacity in the Appalachian region that expires in 2022 and, as a result of the recently completed sale, we no longer have production to satisfy this commitment. While we intend to sell our unused firm transportation in the future to the extent possible, we recorded a charge of $17.3 million representing the liability for estimated discounted future net cash outflows over the remaining term of the contract. The undiscounted amount payable on an annual basis for the each of the next five years is $2.8 million and a combined amount of $13.0 million will be payable for 2018 through expiration in 2022.

During 2011, we completed an organizational restructuring due primarily to our sale of Arkoma Basin properties and consolidation of certain operations functions in our Houston, Texas location. We terminated approximately 40 employees and closed our regional office in Tulsa, Oklahoma. Accordingly, we recorded a charge and recognized an obligation in connection with the long-term lease of that office. In addition to the accrual of these costs, we adjusted the lease obligation associated with the Tulsa office as a result of a change in estimated sub-lease rental income.

During 2010, we incurred special termination benefit costs in connection with the termination of approximately 30 employees and the transfer of certain corporate and division operations functions from our former Kingsport, Tennessee location. We also incurred a charge for the assignment of the lease of that office and relocation costs and other incremental costs associated with staffing and expanding our other office locations.

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

	2012	2011	2010
Balance at beginning of period	$ 576	$ 64	$ 529
Employee, office and other costs accrued, net	1,284	2,351	8,200
Firm transportation charge	17,332	—	—
Accretion of obligations	570	—	—
Cash payments, net	(2,499)	(1,839)	(8,665)
Balance at end of period	$ 17,263	$ 576	$ 64

Restructuring charges are included in the General and administrative expenses caption on our Consolidated Statements of Operations. The initial charge for the firm transportation commitment is presented as a separate caption on our Consolidated Statement of Operations and the accretion of the related obligation, net of any recoveries from the periodic sale of our contractual capacity, is charged as an offset to Other revenue. The current portion of these restructuring and exit cost obligations is included in the Accounts payable and accrued expenses caption and the noncurrent portion is included in the Other liabilities caption on our Consolidated Balance Sheets. As of December, 2012, $2.7 million of the total obligations are classified as current while the remaining $14.5 million are classified as noncurrent.

16. Impairments

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

	Year Ended December 31,		
	2012	2011	2010
Oil and gas properties	$ 103,417	$ 104,688	$ 43,067
Other - tubular inventory and well materials	1,067	—	2,892
	$ 104,484	$ 104,688	$ 45,959

The following table summarizes the aggregate fair values of the assets described below, by asset category and the classification of inputs within the fair value measurement hierarchy, at the respective dates of impairment:

	Fair Value Measurement	Level 1	Level 2	Level 3
Year ended December 31, 2012:				
Long-lived assets held for use	$ 14,801	$ —	$ —	$ 14,801
Long-lived assets sold during the year	96,099	—	—	96,099
Year ended December 31, 2011:				
Long-lived assets held for use	$ 26,625	$ —	$ —	$ 26,625
Long-lived assets sold during the year	30,342	—	—	30,342

In 2012, we recognized a $28.4 million impairment of our legacy assets in West Virginia, Kentucky and Virginia triggered by the expected disposition of these properties, and a $75.0 million impairment of our Marcellus Shale assets due primarily to market declines in natural gas prices and the resultant reduction in proved natural gas reserves. In 2012, we also recognized an impairment of certain tubular inventory and well materials triggered primarily by declines in asset quality. In 2011, we recognized an impairment of our Arkoma Basin assets for $71.1 million, which was triggered by the expected disposition of these properties. Also during 2011, we recognized impairments of our horizontal coal bed methane properties in the Appalachian region for $26.6 million and certain dry-gas properties in Mississippi for $6.8 million, in each case due primarily to market declines in gas prices. In 2010, we recognized an impairment of 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 tubular inventory and well materials triggered primarily by declines in asset quality.

17. Interest Expense

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

	Year Ended December 31,		
	2012	2011	2010
Interest on borrowings and related fees	$ 56,079	$ 51,384	$ 43,060
Accretion of original issue discount	1,367	3,427	8,109
Amortization of debt issuance costs	2,695	3,380	3,875
Capitalized interest	(803)	(1,983)	(1,384)
Other, net	1	8	19
	$ 59,339	$ 56,216	$ 53,679

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,		
	2012	2011	2010
Loss from continuing operations	$ (104,589)	$ (132,915)	$ (65,327)
Income from discontinued operations, net of tax [1]	—	—	33,448
Gain on sale of discontinued operations, net of tax	—	—	51,546
Less net income attributable to noncontrolling interests	—	—	(28,090)
Loss attributable to Penn Virginia Corporation	(104,589)	(132,915)	(8,423)
Less: Preferred stock dividends	(1,687)	—	—
Loss attributable to common shareholders - Basic	(106,276)	(132,915)	(8,423)
Add: Preferred stock dividends [2]	—	—	—
Loss attributable to common shareholders - Diluted	$ (106,276)	$ (132,915)	$ (8,423)
Weighted-average shares - Basic	47,919	45,784	45,553
Effect of dilutive securities [3]	—	—	—
Weighted-average shares - Diluted	47,919	45,784	45,553

[1] For purposes of determining earnings per share, net income attributable to noncontrolling interests is applied against income from discontinued operations as both are attributable to PVG's operations.
[2] Preferred stock dividends were excluded for diluted earnings per share as the assumed conversion of the 6% Preferred Stock would have been anti-dilutive.
[3] For 2012, 2011 and 2010, approximately 19.2 million, 0.1 million and 0.2 million potentially dilutive securities, including the 6% Preferred Stock, 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 and recognized a gain on the sale of discontinued operations of $51.5 million, net of income taxes of $35.1 million.

Income from discontinued operations represents the results of operations of PVG, which include the results of operations of PVR. 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 in June 2010.

	Year Ended December 31,		
	2012	2011	2010
Revenues	$ —	$ —	$ 303,206
Income from discontinued operations before taxes	$ —	$ —	$ 36,832
Income tax expense [1]	—	—	(3,384)
Income from discontinued operations, net of taxes	$ —	$ —	$ 33,448

[1] Determined by applying the effective tax rate attributable to discontinued operations to the income from discontinued operations less noncontrolling interests attributable to PVG's operations.

During 2011, we terminated certain agreements under which PVR provided marketing and gas gathering and processing services to us. 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
2012								
Revenues	$	84,411	$	76,845	$	77,699	$	78,194
Operating loss [1]	$	(3,422)	$	(38,043)	$	(24,485)	$	(81,141)
Loss attributable to Penn Virginia Corp.	$	(11,899)	$	(5,638)	$	(32,611)	$	(54,441)
Loss per share - Basic [2]	$	(0.26)	$	(0.12)	$	(0.71)	$	(1.05)
Loss per share - Diluted [2]	$	(0.26)	$	(0.12)	$	(0.71)	$	(1.05)
Weighted-average shares outstanding:								
Basic		45,945		46,030		46,050		53,607
Diluted		45,945		46,030		46,050		53,607
2011								
Revenues	$	68,583	$	73,618	$	83,353	$	80,451
Operating loss [3]	$	(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

[1] Includes impairments of oil and gas properties of $28.6 million, $0.7 million and $75.2 million during the quarters ended June 30, 2012, September 30, 2012 and December 31, 2012, 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 impairments of $71.1 million and $33.6 million during the quarters ended June 30, 2011 and December 31, 2011, 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,		
	2012	2011	2010
Proved properties	$ 240,217	$ 277,987	$ 293,486
Unproved properties	60,746	120,288	171,303
Wells, equipment and facilities	2,107,061	2,081,103	1,840,154
Support equipment	6,815	6,645	6,254
	2,414,839	2,486,023	2,311,197
Accumulated depreciation and depletion	(693,123)	(710,948)	(609,380)
Net capitalized costs	$ 1,721,716	$ 1,775,075	$ 1,701,817

ARO assets of $0.1 million, $0.2 million and $0.1 million were added to the cost basis of proved properties during the years ended December 31, 2012, 2011 and 2010, respectively.

Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
	2012	2011	2010
Proved property acquisition costs	$ —	$ —	$ 5,671
Unproved property acquisition costs	27,775	47,877	133,185
Exploration costs	50,883	77,460	66,886
Development costs and other	305,693	320,263	244,092
Total costs incurred	$ 384,351	$ 445,600	$ 449,834

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,		
	2012	2011	2010
Revenues	$ 310,484	$ 300,046	$ 251,336
Production expenses	56,096	65,835	63,854
Exploration expenses	34,092	78,943	49,641
Depreciation and depletion expense	204,849	160,293	130,816
Impairment of oil and gas properties	104,484	104,688	45,959
	(89,037)	(109,713)	(38,934)
Income tax expense (benefit)	(34,724)	(42,788)	(15,184)
Results of operations	$ (54,313)	$ (66,925)	$ (23,750)

A combined total of depletion and accretion expense related to AROs of $0.5 million, $0.7 million and $0.7 million was recognized in DD&A expense during the years ended December 31, 2012, 2011 and 2010, respectively.

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, NGLs and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future prices for these commodities 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 reserve estimate by our independent third party engineers, Wright & Company, Inc. Our Manager of Engineering has over 27 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. Our 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.

The table on the following page sets forth our 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, NGL and natural gas reserves for the three years ended December 31, 2012 were estimated by Wright & Company, Inc. utilizing data compiled by us.

Proved Developed and Undeveloped Reserves	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total Equivalents (MBOE)
December 31, 2009	11,517	14,870	776,665	155,831
Revisions of previous estimates [1]	(2,410)	7,611	(71,421)	(6,702)
Extensions, discoveries and other additions [2]	513	3,556	90,439	19,142
Production	(710)	(671)	(38,919)	(7,867)
Purchase of reserves	9	—	3,288	557
Sale of reserves in place	(837)	(653)	(15,070)	(4,002)
December 31, 2010	8,082	24,713	744,982	156,959
Revisions of previous estimates [3]	(2,367)	(3,047)	(61,165)	(15,608)
Extensions, discoveries and other additions [4]	9,669	732	56,345	19,792
Production	(1,283)	(907)	(33,410)	(7,758)
Purchase of reserves	20	—	1	20
Sale of reserves in place	(42)	—	(36,840)	(6,182)
December 31, 2011	14,079	21,491	669,913	147,223
Revisions of previous estimates [5]	(439)	(2,495)	(154,372)	(28,662)
Extensions, discoveries and other additions [6]	13,444	2,578	13,405	18,255
Production	(2,252)	(884)	(20,261)	(6,513)
Purchase of reserves	39	1	6	41
Sale of reserves in place	(20)	—	(101,172)	(16,882)
December 31, 2012	24,851	20,691	407,519	113,462
Proved Developed Reserves:				
December 31, 2010	4,035	10,778	412,644	83,587
December 31, 2011	7,075	9,395	330,552	71,562
December 31, 2012	10,472	8,266	169,449	46,980
Proved Undeveloped Reserves:				
December 31, 2010	4,047	13,935	332,338	73,372
December 31, 2011	7,004	12,096	339,361	75,661
December 31, 2012	14,379	12,425	238,070	66,482

[1] We had downward revisions of 6.7 MMBOE primarily as a result of the following: 1) downward revisions of 7.5 MMBOE due to the removal of 200 proved undeveloped locations that would not be developed within five years, 2) upward revisions of 5.7 MMBOE as a result of processing the gas in the Mid-Continent Granite Wash for NGLs, 3) upward revisions of 2.0 MMBOE due to higher prices and 4) various downward revisions for 6.5 MMBOE across our assets as a result of well performance, lease expirations and interest changes.

[2] We added 19.1 MMBOE due to the drilling of 16 wells on locations not classified as proved undeveloped locations in our 2010 year-end reserve report and the addition of 51 new proved undeveloped locations, primarily in East Texas, as a result of our 2011 drilling activities .

[3] We had downward revisions of 15.6 MMBOE primarily as a result of the following: 1) downward revisions of 12.0 MMBOE 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 1.7 MMBOE due to lower condensate yield in the Granite Wash, 3) downward revisions of 1.5 MMBOE attributable to the elimination of proved undeveloped locations particularly in the Haynesville Shale in East Texas, 4) downward revisions of 0.8 MMBOE due to lower natural gas prices and 5) upward revisions of 0.5 MMBOE due to higher gas processing yields in the Haynesville Shale and Granite Wash .

[4] We added 19.8 MMBOE due primarily to an increase of 9.0 MMBOE 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 10.8 MMBOE .

[5] We had downward revisions of 28.7 MMBOE primarily as a result of the following: 1) downward revisions of 5.0 MMBOE due to well performance issues, interest changes and economic limits due to operating conditions, including lease operating expense and basis differentials, primarily in the Selma Chalk, the Granite Wash, the Cotton Valley, and the Haynesville and Marcellus Shales, 2) downward revisions of 15.0 MMBOE due to lower natural gas prices which significantly reduced the number of proved undeveloped locations in the Marcellus Shale and Selma Chalk and 3) downward revisions of 8.7 MMBOE due to the removal of 38 proved undeveloped locations that would not be developed within five years primarily in the Selma Chalk, the Cotton Valley and the Haynesville Shale.

[6] We added 18.3 MMBOE due primarily to the drilling of 18 wells and the addition of 48 proved undeveloped locations in the Eagle Ford Shale.

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,		
	2012	2011	2010
Future cash inflows	$ 4,365,357	$ 5,032,915	$ 4,833,030
Future production costs	(1,206,478)	(1,374,658)	(1,388,857)
Future development costs	(1,118,859)	(1,091,100)	(879,193)
Future net cash flows before income tax	2,040,020	2,567,157	2,564,980
Future income tax expense	(548,132)	(665,751)	(687,928)
Future net cash flows	1,491,888	1,901,406	1,877,052
10% annual discount for estimated timing of cash flows	(994,014)	(1,246,910)	(1,235,633)
Standardized measure of discounted future net cash flows	$ 497,874	$ 654,496	$ 641,419

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

	Year Ended December 31,		
	2012	2011	2010
Sales of oil and gas, net of production costs	$ (254,388)	$ (234,211)	$ (180,568)
Net changes in prices and production costs	(207,045)	(25,398)	180,316
Extensions, discoveries and other additions	355,495	361,284	59,729
Development costs incurred during the period	119,706	44,741	153,563
Revisions of previous quantity estimates	(196,152)	(113,188)	(50,471)
Purchases of reserves-in-place	1,156	308	2,239
Sale of reserves-in-place	(116,151)	(37,474)	(47,740)
Accretion of discount	87,441	87,815	68,817
Net change in income taxes	25,312	16,818	(73,332)
Other changes	28,004	(87,618)	4,095
Net increase (decrease)	(156,622)	13,077	116,648
Beginning of year	654,496	641,419	524,771
End of year	$ 497,874	$ 654,496	$ 641,419

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, 2012. 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, 2012, 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, 2012. 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, 2012, 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, 2012, 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 2012 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 16, 2012,among Penn Virginia Oil & Gas Corporation, EnerVest Energy Institutional Fund XII-A, L.P., EnerVest Energy Institutional Fund XII-WIB, L.P. and EnerVest Energy Institutional Fund XII-WIC, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on July 18, 2012).

(2.1.1) Amendment and Supplement to Purchase and Sale Agreement, dated July 31, 2012,among Penn Virginia Oil & Gas Corporation, EnerVest Energy Institutional Fund XII-A, L.P., EnerVest Energy Institutional Fund XII-WIB, L.P. and EnerVest Energy Institutional Fund XII-WIC, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on August 2, 2012).

(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).

(3.1.5) 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 October 17, 2012).

(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 20, 2013).

(4.1) 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).

(4.1.1) 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).

(4.1.2) 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).

(4.1.3) 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).

(4.1.4) 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).

(4.1.5) Form of Note for 7.25% Senior Notes due 2019 (incorporated by reference to Annex A to Exhibit 4.3 to Registrant's Current Report on Form 8-K filed on April 14, 2011).

(4.2) Deposit Agreement, dated October 17, 2012, among Penn Virginia Corporation, American Stock Transfer & Trust Company, LLC and the holders from time to time of the depositary shares described therein (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on October 17, 2012).

(4.2.1) Form of depositary receipt representing the Depositary Shares (incorporated by reference to Exhibit A to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on October 17, 2012).

(10.1) Credit Agreement dated as of September 28, 2012 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 2, 2012).

(10.2) 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).*

(10.2.1) Amendment 2009-1 to the Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.4.1 to Registrant's Annual report on Form 10-K for the year ended December 31, 2011).*

(10.3) 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).*

(10.3.1) 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).*

(10.4) 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). *

(10.4.1) 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).*

(10.5) 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).*

(10.5.1) 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).*

(10.5.2) 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).*

(10.5.3) 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).*

(10.5.4) 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).*

(10.5.5) Form of Agreement for Performance Based Restricted Stock Unit Awards under the 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 February 23, 2012).*

(10.6) Amended and Restated Executive Change of Control Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*

(10.7) Amended and Restated Executive Change of Control Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*

(10.8) Amended and Restated Executive Change of Control Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Steven A. Hartman (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*

(10.9) Executive Change of Control Severance Agreement dated January 29, 2013 between Penn Virginia Corporation and John A. Brooks (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on February 1, 2013). *

(10.10) Amended and Restated Change of Location Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*

(10.11) 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/A filed on February 7, 2013).*

(10.12) Confidential Severance Agreement and Release dated August 31, 2012 between Penn Virginia Corporation and Michael E. Stamper (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on September 5, 2012).

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

(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 18, 2013 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

* 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
	By:	/s/ STEVEN A. HARTMAN **Steven A. Hartman** **Senior Vice President and Chief Financial Officer**
February 25, 2013	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 25, 2013
/s/ JOHN U. CLARKE **John U. Clarke**	Director	February 25, 2013
/s/ STEVEN W. KRABLIN **Steven W. Krablin**	Director	February 25, 2013
/s/ MARSHA R. PERELMAN **Marsha R. Perelman**	Director	February 25, 2013
Philippe van Marcke de Lummen	Director	February 25, 2013
/s/ H. BAIRD WHITEHEAD **H. Baird Whitehead**	Director and President and Chief Executive Officer	February 25, 2013
/s/ GARY K. WRIGHT **Gary K. Wright**	Director	February 25, 2013

Exhibit 12.1

Penn Virginia Corporation and Subsidiaries
Statement of Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividends
(in thousands, except ratios)

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Earnings:					
Income (loss) from continuing operations before income taxes	$ (173,291)	$ (221,070)	$ (108,178)	$ (216,750)	$ 149,225
Fixed charges	66,616	62,002	60,003	52,539	33,772
Capitalized interest	(803)	(1,983)	(1,384)	(2,318)	(2,987)
Preferred stock dividend requirements	(2,793)	—	—	—	—
	$ (110,271)	$ (161,051)	$ (49,559)	$ (166,529)	$ 180,010
Fixed charges:					
Interest expense	$ 59,339	$ 56,216	$ 53,679	$ 44,231	$ 24,627
Capitalized interest	803	1,983	1,384	2,318	2,987
Rent factor	3,681	3,803	4,940	5,990	6,158
Preferred stock dividend requirements	2,793	—	—	—	—
	$ 66,616	$ 62,002	$ 60,003	$ 52,539	$ 33,772
Ratio of earnings to fixed charges and preferred stock dividends [1]	—	—	—	—	5.3x

[1] During 2012, 2011, 2010 and 2009, earnings were deficient by $176,887, $223,053, $109,562 and $219,068, respectively, regarding the coverage of fixed charges and preferred stock dividends.

Exhibit 21.1

Subsidiaries of Penn Virginia Corporation

Name	Jurisdiction of Organization
Penn Virginia Holding Corp.	Delaware
Penn Virginia Oil & Gas Corporation	Virginia
Penn Virginia Oil & Gas, L.P.	Texas
Penn Virginia Oil & Gas GP LLC	Delaware
Penn Virginia Oil & Gas LP LLC	Delaware
Penn Virginia MC Corporation	Delaware
Penn Virginia MC Energy L.L.C.	Delaware
Penn Virginia MC Operating Company L.L.C	Delaware
Penn Virginia MC Gathering Company L.L.C.	Oklahoma
Penn Virginia Resource Holdings Corp.	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Penn Virginia Corporation:

We consent to the incorporation by reference in the registration statements on Form S-3 (No. 333-183365) and on Form S-8 (No. 33-59647, 333-82304, 333-96463, 333-96465, 333-82274, 333-103455, 333-143514, 333-159304, and 333-173990) of Penn Virginia Corporation of our report dated February 25, 2013, with respect to the consolidated balance sheets of Penn Virginia Corporation as of December 31, 2012 and 2011, 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, 2012, and the effectiveness of internal control over financial reporting as of December 31, 2012, which report appears in the December 31, 2012 annual report on Form 10-K of Penn Virginia Corporation.

/s/ KPMG LLP

Houston, Texas
February 25, 2013

Exhibit 23.2

CONSENT OF WRIGHT & COMPANY, INC.

As independent petroleum consultants, Wright & Company, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-59647, 333-96463, 333-82274, 333-96465, 333-103455, 333-143514, 333-82304, 333-159304 and 333-173990) and Form S-3 (No. 333-183365) of Penn Virginia Corporation of information from our reserves report titled "Evaluation of Oil and Gas Reserves, To the Interests of Penn Virginia Corporation, In Certain Properties Located in Various States, Pursuant to the Requirements of the Securities and Exchange Commission, Effective January 1, 2013, Job 12.1450," dated January 18, 2013, and all references to our firm included in or made a part of the Penn Virginia Corporation Annual Report on Form 10-K to be filed with the Securities and Exchange Commission on or about February 25, 2013.

Wright & Company, Inc.
TX Firm Reg. No. F-12302

/s/ D. Randall Wright

By: D. Randall Wright
President

Brentwood, Tennessee
February 25, 2013

Exhibit 31.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, H. Baird Whitehead, President and Chief Executive Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

    (d) Disclosed in this Report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: February 25, 2013

/s/ H. BAIRD WHITEHEAD

H. Baird Whitehead
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven A. Hartman, Senior Vice President and Chief Financial Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

   (d) Disclosed in this Report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: February 25, 2013

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, H. Baird Whitehead, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2013

/s/ H. BAIRD WHITEHEAD

H. Baird Whitehead
President and Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn Virginia Corporation (the “Company”) on Form 10-K for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Steven A. Hartman, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2013

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President and Chief Financial Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

January 18, 2013

Penn Virginia Corporation
Four Radnor Corporate Center
100 Matsonford Road, Suite 200
Radnor, PA 19087

Attention: Mr. Frank E. Falbo, Jr.

SUBJECT: Evaluation of Oil and Gas Reserves
To the Interests of Penn Virginia Corporation
In Certain Properties Located in Various States
Pursuant to the Requirements of the
Securities and Exchange Commission
Effective January 1, 2013
Job 12.1450

At the request of Penn Virginia Corporation (PVA), Wright & Company, Inc. (Wright) has performed an evaluation to estimate proved reserves and associated cash flow and economics from certain properties to the subject interests. This evaluation was authorized by Mr. Frank E. Falbo, Jr. of PVA. Projections of the reserves and cash flow to the evaluated interests were based on specified economic parameters, operating conditions, and government regulations considered applicable at the effective date. This reserves evaluation is pursuant to the financial reporting requirements of the Securities and Exchange Commission (SEC) as specified in Regulation S-X, Rule 4-10(a) and Regulation
S-K, Rule 1202(a)(8). It is the understanding of Wright that the purpose of this evaluation is for inclusion in relevant registration statements or other filings to the SEC. The effective date of this report is January 1, 2013. The report was completed January 18, 2013. The following is a summary of the results of the evaluation.

Penn Virginia Corporation SEC Parameters	Proved Developed		Total Proved Developed (PDP & PDNP)	Proved Undeveloped (PUD)	Total Proved (PDP, PDNP & PUD)
	Producing (PDP)	Nonproducing (PDNP)			
Net Reserves to the Evaluated Interests					
Oil, Mbbl:	10,172.620	299.484	10,472.105	14,379.311	24,851.420
Gas, MMcf:	152,016.719	17,432.609	169,449.312	238,069.531	407,518.875
NGL, Mbbl:	7,019.011	1,246.992	8,266.002	12,424.892	20,690.893
Gas Equivalent, MMcfe: (1 bbl = 6 Mcfe)	255,166.505	26,711.465	281,877.954	398,894.749	680,772.753
Cash Flow (BTAX), M$					
Undiscounted:	1,109,432.625	50,607.148	1,160,039.625	879,980.500	2,040,020.375
Discounted at 10% Per Annum:	612,613.562	15,315.269	627,928.688	64,543.137	692,471.625

Please note numbers in table may not add due to rounding techniques in the ARIES™ petroleum software program.

The properties evaluated in this report are located in the states of Louisiana, Mississippi, Oklahoma, Pennsylvania, and Texas. According to PVA, the total proved reserves included in this evaluation represent 100 percent of the reported total proved reserves of PVA.

Proved oil and gas reserves are those quantities of oil and gas which can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods, and government regulations. As specified by the SEC regulations, when calculating economic producibility, the base product price must be the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the prior 12-month period. The benchmark base prices used for this evaluation were $94.71 per barrel for West Texas Intermediate oil at Cushing, OK and $2.757

per Million British thermal units (MMBtu) for natural gas at Henry Hub, LA. These benchmark base prices were adjusted for energy content, quality, and basis differential, as appropriate. The average adjusted product prices used to estimate proved reserves are $102.24 per barrel of oil and $2.473 per Mcf of gas. The Natural Gas Liquids (NGL) product price was estimated to be approximately 42 percent of the base oil price, resulting in an average adjusted price of $39.48 per barrel. Product prices were held constant for the life of the properties.

Oil and other liquid hydrocarbon volumes are expressed in thousands of United States (U.S.) barrels (Mbbl), one barrel equaling 42 U.S. gallons. Gas volumes are expressed in millions of standard cubic feet (MMcf) at 60 degrees Fahrenheit and at the legal pressure base that prevails in the state in which the reserves are located. No adjustment of the individual gas volumes to a common pressure base has been made.

Net income to the evaluated interests is the cash flow after consideration of royalty revenue payable to others, standard state and county taxes or fees, operating expenses, and investments, as applicable. The cash flow is before federal income tax (BTAX) and excludes consideration of any encumbrances against the properties if such exist. The Cash Flow (BTAX) was discounted monthly at an annual rate of 10.00 percent (PCT) in accordance with the reporting requirements of the SEC.

The estimates of reserves contained in this report were determined by accepted industry methods, and the procedures used in this evaluation are appropriate for the purpose served by the report. Where sufficient production history and other data were available, reserves for producing properties were determined by extrapolation of historical production or sales trends. Analogy to similar producing properties was used for development projects and for those properties that lacked sufficient production history to yield a definitive estimate of reserves. When appropriate, Wright may have also utilized volumetric calculations and log correlations in the determination of estimated ultimate recovery (EUR). These calculations are often based upon limited log and/or core analysis data and incomplete formation fluid and rock data. Since these limited data must frequently be extrapolated over an assumed drainage area, subsequent production performance trends or material balance calculations may cause the need for significant revisions to the estimates of reserves. Wright has used all methods and procedures as it considered necessary under the circumstances to prepare this report.

Oil and gas reserves were evaluated for the proved developed producing (PDP), proved developed nonproducing (PDNP) and proved undeveloped (PUD) reserves categories. The summary classification of total proved reserves combines the PDP, PDNP and PUD categories. In preparing this evaluation, no attempt has been made to quantify the element of uncertainty associated with any category. Reserves were assigned to each category as warranted. Wright is not aware of any local, state, or federal regulations that would preclude PVA from continuing to produce from currently active wells or to fully develop those properties included in this report.

There are significant uncertainties inherent in estimating reserves, future rates of production, and the timing and amount of future costs. The estimation of oil and gas reserves must be recognized as a subjective process that cannot be measured in an exact way, and estimates of others might differ materially from those of Wright. The accuracy of any reserves estimate is a function of the quantity and quality of available data and of subjective interpretations and judgments. It should be emphasized that production data subsequent to the date of these estimates or changes in the analogous properties may warrant revisions of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

All data utilized in the preparation of this report were provided by PVA. No inspection of the properties was made as this was not considered to be within the scope of this evaluation. Wright has not independently verified the accuracy and completeness of information and data furnished by PVA with respect to ownership interests, oil and gas production or sales, historical costs of operation and development, product prices, or agreements relating to current and future operations and sales of production. Wright requested and received detailed information allowing Wright to check and confirm any calculations provided by PVA with regard to product pricing, appropriate adjustments, lease operating expenses, and capital investments for drilling the undeveloped locations. Furthermore, if in the course of Wright's examination something came to our attention that brought into question the validity or sufficiency of any information or data, Wright did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data. In accordance with the requirements of the SEC, all operating costs were held constant for the life of the properties.

In accordance with the instructions of PVA, abandonment costs net of salvage values were included, as appropriate. Wright has not performed a detailed study of the abandonment costs nor the salvage values and offers no opinion as to PVA's calculations.

Wright is not aware of any potential environmental liabilities that may exist concerning the properties evaluated. There are no costs included in this evaluation for potential property restoration, liability, or clean up of damages, if any, that may be necessary due to past or future operating practices.

Wright is an independent petroleum consulting firm founded in 1988 and owns no interests in the oil and gas properties covered by this report. No employee, officer, or director of Wright is an employee, officer, or director of PVA, nor does Wright or any of its employees have direct financial interest in PVA. Neither the employment of nor the compensation received by Wright is contingent upon the values assigned or the opinions rendered regarding the properties covered by this report.

This report is prepared for the information of PVA, its shareholders, and for the information and assistance of its independent public accountants in connection with their review of and report upon the financial statements of PVA, and for reporting disclosures as required by the SEC. This report is also intended for public disclosure as an exhibit in filings made to the SEC by PVA.

Based on data and information provided by PVA, and the specified economic parameters, operating conditions, and government regulations considered applicable at the effective date, it is Wright's conclusion that this report provides a fair and accurate representation of the oil and gas reserves to the interests of PVA in those certain properties included in this report.

The professional qualifications of the petroleum consultants responsible for the evaluation of the reserves and economics information presented in this report meet the standards of Reserves Estimator as defined in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* as promulgated by the Society of Petroleum Engineers.

It has been a pleasure to serve you by preparing this evaluation. All related data will be retained in our files and are available for your review.

Very truly yours,

Wright & Company, Inc.
TX Reg. No. F-12302

By: /s/ D. Randall Wright
D. Randall Wright
President