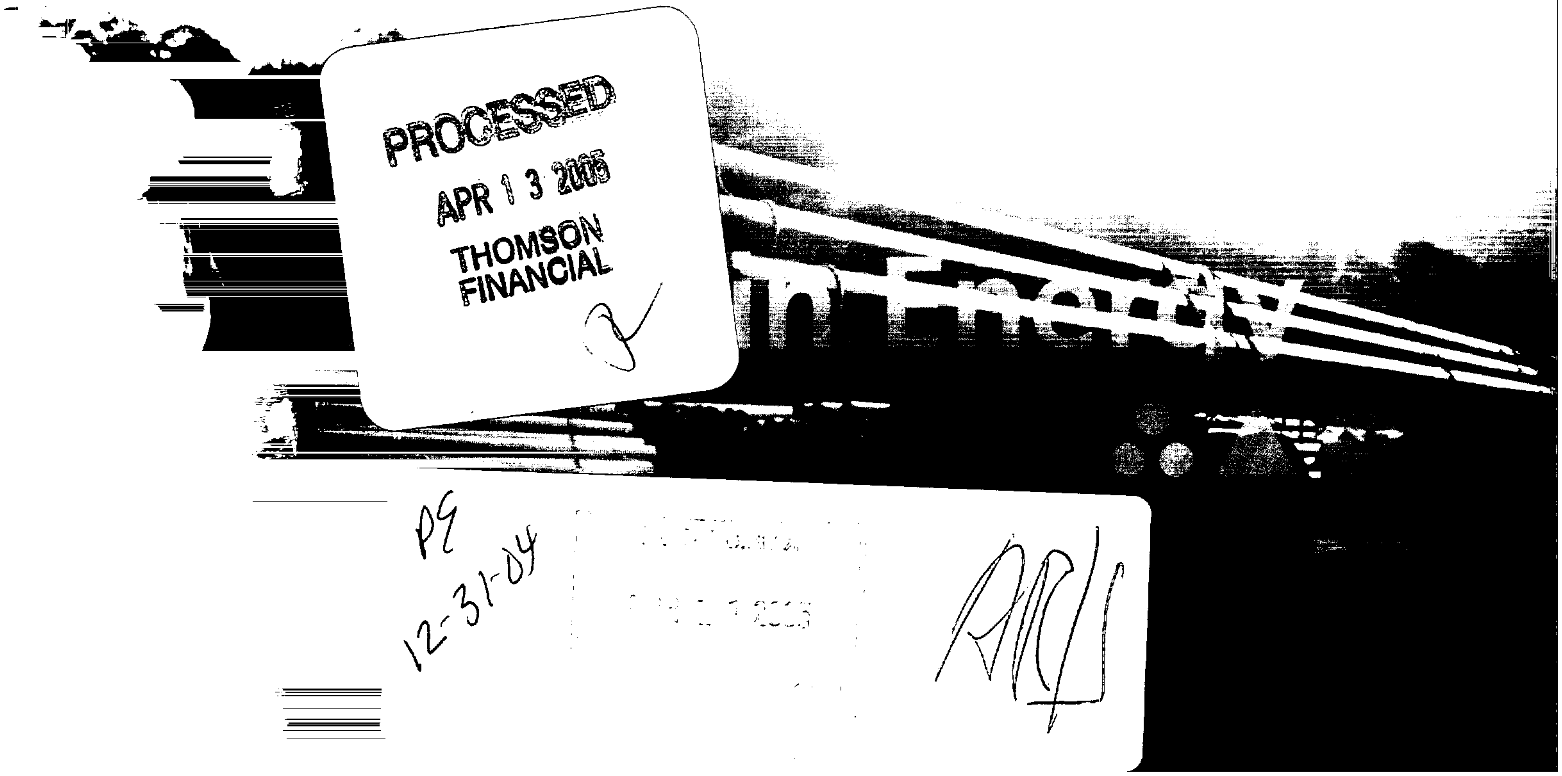
PENN VIRGINIA
CORPORATION



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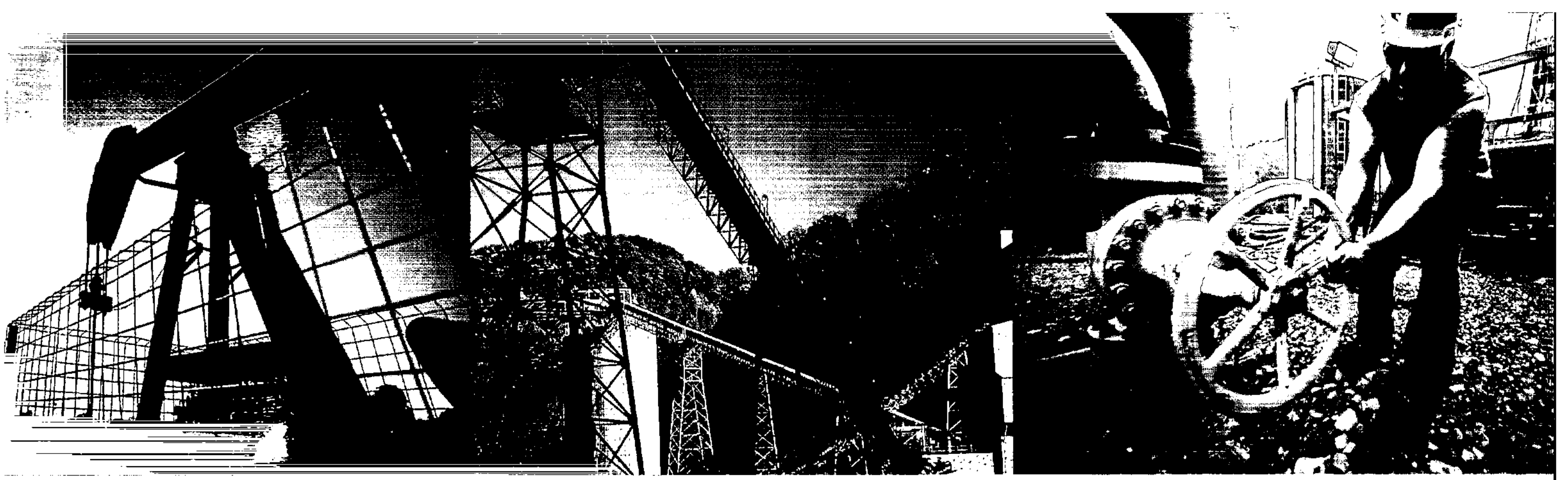


2004 ANNUAL REPORT

PENN VIRGINIA CORPORATION (NYSE:PVA) IS AN ENERGY COMPANY ENGAGED IN THE ACQUISITION, EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL AND NATURAL GAS. THROUGH ITS OWNERSHIP IN PENN VIRGINIA RESOURCE PARTNERS, L.P. (NYSE:PVR), A PUBLICLY-TRADED MASTER LIMITED PARTNERSHIP (MLP), PVA IS ALSO IN THE BUSINESS OF MANAGING COAL PROPERTIES AND RELATED ASSETS. FOR MORE INFORMATION ABOUT PVA, VISIT THE COMPANY'S WEBSITE AT WWW.PENNVIRGINIA.COM.

Abbreviations:

Bbl: Barrel
Bcf: Billion Cubic Feet
Bcfe: Billion Cubic Feet Equivalent
CBM: Coalbed Methane
HCBM: Horizontal CBM
Mbbl: Thousand Barrels
MMbbl: Million Barrels
Mcf: Thousand Cubic Feet
Mcfe: Thousand Cubic Feet Equivalent
MMcf: Million Cubic Feet
MMcfe: Million Cubic Feet Equivalent
MMbtu: Million British Thermal Units

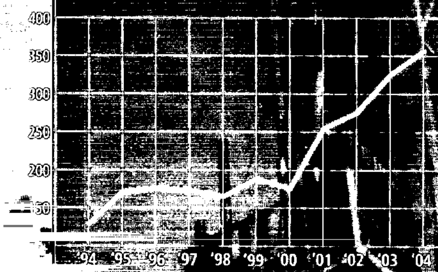
FINANCIAL HIGHLIGHTS

In millions except per share data	**2004**	2003	2002	2001	2000
Financial Data					
Revenues	**$ 228.4**	$ 181.3	$ 111.0	$ 96.6	$ 106.0
Operating Income(1)	**80.8**	62.1	30.8	1.6	65.7
Net Income(2)	**33.4**	28.5	12.1	34.3	39.3
Net Cash Flows Provided by Operating Activities	**146.4**	109.7	65.8	44.2	41.7
Common Share Data(3)					
Net Income, Basic ($/share)	**$ 1.82**	$ 1.59	$ 0.68	$ 1.96	$ 2.38
Net Income, Diluted ($/share)	**1.81**	1.58	0.67	1.93	2.35
Dividends Paid ($/share)	**0.45**	0.45	0.45	0.45	0.45
Average Shares Outstanding, Diluted	**18.5**	18.1	17.9	17.8	16.7
Capitalization					
Net Long-term Debt(4)	**$ 188.9**	$ 154.3	$ 106.9	$ 3.5	$ 47.5
Minority Interest in Penn Virginia Resource Partners	**182.9**	190.5	192.8	144.0	—
Shareholder's Equity	**252.9**	211.6	188.0	185.5	171.2
Total Capitalization	**624.7**	556.4	487.7	333.0	218.7
Percent of Net Long-term Debt to Total Capitalization	**30.2%**	27.7%	21.9%	1.1%	21.7%
Summary Operating Data Production					
Oil and Condensate (Mbbl)	**396**	625	349	164	31
Natural Gas (Bcf)	**22.1**	20.1	18.7	13.1	11.6
Total Oil and Gas Production (Bcfe)	**24.5**	23.8	20.8	14.1	11.8
Daily Production (MMcfe)	**66.8**	65.2	57.0	38.6	32.3
Coal Produced by Lessees (Millions of tons)	**31.2**	26.5	14.3	15.3	12.5
Realized Prices					
Oil and Condensate ($/Bbl)	**$ 33.75**	$ 26.91	23.63	$ 22.94	$ 26.84
Natural Gas ($/Mcf)	**6.27**	5.31	3.35	4.06	3.95
Coal Royalties ($/Ton)	**2.23**	1.90	2.20	2.11	1.94
Estimated Reserves					
Oil and Condensate (MMbbl Proved)	**6.3**	6.6	5.4	3.9	0.1
Natural Gas (Bcf Proved)	**316.1**	283.1	241.3	229.3	174.2
Total Proved Oil and Gas Reserves (Bcfe)	**354.1**	322.9	273.4	252.8	174.7
Coal (Millions of Recoverable Tons)	**558.1**	588.2	614.8	492.8	480.0

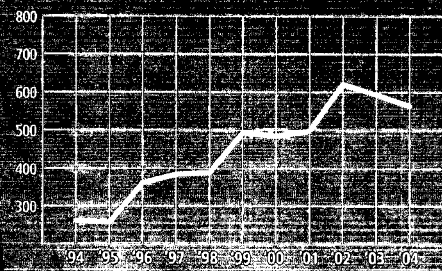
(1) Operating income in 2004 included $8.2 million of loss on assets held for sale and impairment of oil and gas properties.
(2) Net income in 2001 included a $54.7 million ($35.6 million after tax) gain on the sale of Norfolk Southern Corporation common stock.
(3) Amounts per common share in 2000 through 2003 have been adjusted for the effect of a two-for-one stock split effective on June 3, 2004.
(4) Net of $43.4 million cash equivalents held as collateral for the debt as of December 31, 2001.

Ten Years of Growth

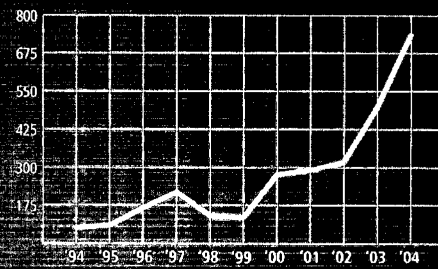
Proved Oil & Gas Reserves
(BCFE)



Proven and Probable Coal Reserves
(Millions of tons)



Cumulative Shareholder Return
($100 invested 1/1/95)

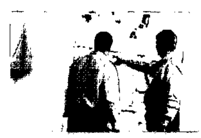


Significant Milestones

1996
- **Restructuring Begins**
Penn Virginia gets back coal under lease to Westmoreland Coal Company. Represents 85% of existing reserves. Purchase new reserves in 1997 and 1998.

1999
- **Expansion Outside Appalachia**
Acquires 23 Bcfe of proved oil and gas reserves in Gwinville field in Mississippi. Additional properties in 2002 and 2003.

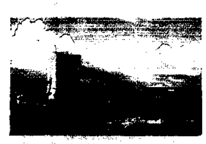
2000
- **Focus on CBM Begins**
Acquires 506,000 acres of oil and gas rights in central Appalachia. Includes 35 Bcfe of proved reserves and coalbed methane rights.



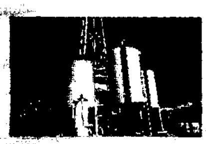
2001
- **Platform for Growth in Oil & Gas**
Buys Gulf Coast oil and gas property with 60 Bcfe of proved and significant probable reserves for $112MM of cash.

2001
- **Penn Virginia Resource is Born**
Successful IPO of Penn Virginia Resource Partners, LP (PVR). Sells 48% of units, raises over $140MM. Retains 52% of units and 100% of GP.

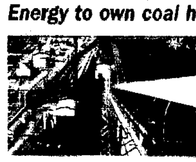
2002
- **Geographic Diversity in Coal**
PVR acquires 120MM tons of proven coal reserves from Peabody Energy Corp for $125MM of cash and units.



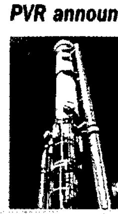
2003
- **Gulf Coast Oil & Gas Expansion**
Acquires 25% working interest in Kingsville field in South Texas, adding 22 Bcfe of proved oil and gas reserves.



2004
- **New Direction in Coal Infrastructure**
PVR acquires 50% interest in coal handling joint venture with Massey Energy to own coal handling facilities.

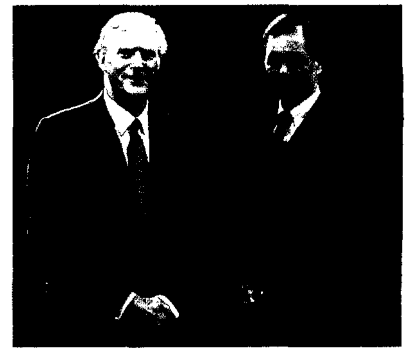


2004
- **Natural Gas Midstream Growth Engine for PVR**
PVR announces acquisition of Cantera midstream oil and gas business for $191MM of cash.



Dear Fellow Shareholder:

It is a pleasure to report that Penn Virginia Corporation enjoyed another very successful year. Revenues in 2004 were up 26 percent over 2003 to a record $228 million and operating income increased 30 percent over 2003 to $81 million, also a record. Net cash provided by operating activities was up 34 percent to $146 million and operating cash flow, a non-GAAP measure, was up 38 percent to $156 million with both measures at record levels. During 2004, Penn Virginia's stock price, adjusted for the effect of the June 3 two-for-one split, increased 46 percent.



Robert Garrett
Chairman

A. James Dearlove
President and
Chief Executive Officer

The oil and gas segment of the Company recorded a modest increase in production, which, when coupled with the high commodity prices experienced by the entire industry, resulted in record levels of revenue, operating income and cash flow. Penn Virginia Resource Partners, LP (NYSE:PVR), the coal royalty based master limited partnership (MLP) controlled by Penn Virginia, experienced record levels of coal production from its properties and benefited significantly from the very strong market, particularly for eastern coal. PVR's unit price increased 52 percent during 2004.

Unique in Energy

For the past several years Penn Virginia has used the tag line "Unique in Energy." This phrase arose from the Company's combination of a growing presence in the upstream natural gas business and its 122-year involvement in the coal reserve and land management business. Being exposed to both natural gas and coal provides diversity as well as a unique perspective when evaluating upstream energy assets.

Going forward, Penn Virginia will continue to expand both segments of its business. An important focus of the oil and gas group will be on utilizing the Company's specialized know-how in developing unconventional formations especially using horizontal drilling techniques. The Company will also continue to exploit its low risk development opportunities in Appalachia, Mississippi and Texas.

The 2005 capital budget for oil and gas is $146 million, which includes $85 million to be spent on development drilling, an increase of $8 million over 2004.

A strong emphasis will also be placed on replenishing the Company's inventory of low risk development prospects. Penn Virginia has budgeted $26 million in 2005 for lease acquisition and seismic processing to identify, evaluate and pursue opportunities in its core areas and other domestic geologic basins. Although the focus is on growth through the drillbit, acquisition candidates are continuously being evaluated.

Penn Virginia will also continue to expand its MLP. During 2004, PVR made two important diversification moves. In July, the Partnership entered into a joint venture with Massey Energy (NYSE:MEE) to provide coal handling services to various industrial end-users. In the past PVR had built or bought, then operated coal handling facilities, on its own property. The coal handling joint venture extends the concept to the customers to whom coal is delivered from any source. A second significant diversification step was PVR's anticipated entry into the midstream natural gas business. On November 23, 2004, the Partnership announced it had signed a definitive purchase and sale agreement to acquire a natural gas gathering and processing business with assets in Oklahoma and Texas from Cantera Resource Holdings LLC (Cantera). Closing on the $191 million cash transaction occurred in March 2005. The new business segment is named PVR Midstream.

Changes in Governance

During May of 2004, Mr. Joe T. Rye resigned from Penn Virginia's Board of Directors. Having served since 1997, Joe was one of the directors who helped to launch the Company's "Unique in Energy" strategy. He was the very able head of the Audit Committee for several years and his sage advice will be missed.

On January 30, 2005, Mr. H. Jarrell Gibbs resigned from the Board of Directors of the Company for personal reasons. Jarrell joined the Board in 2003, and his wisdom and gracious good counsel will be missed.

In December of 2004, Penn Virginia was honored to have two experienced and well regarded individuals, Messrs. Joe N. Averett, Jr. and Steven W. Krablin, join its Board. Mr. Averett has over 33 years of experience in the energy industry, including 18 years as President and CEO of Crystal Gas Storage, Inc., an oil and gas exploration and production and natural gas storage company. Prior to Crystal Gas Storage, Mr. Averett served as chief financial officer for several companies in the energy industry. Mr. Krablin has served as the Senior Vice President and Chief Financial Officer of National Oilwell, Inc. (NYSE:NOI), a leading global provider of drilling equipment and other oil industry goods and services since 1996. He has over 22 years of experience as a senior financial executive in public companies involved in the energy industry and is a certified public accountant.

Outlook

Natural gas and crude oil prices approached record levels in 2004, and although it is impossible to predict with certainty whether they will remain as high in 2005, the fundamentals indicate commodity prices will remain strong relative to historical levels. Although price forecasts vary, the consensus among industry professionals is that the long term sustainable price of natural gas will remain above $4.50 per Mcf.

Coal prices also appear to have reached a new plateau. Coal demand is increasing for electricity generation, steel making and export. Supply is tightening, especially in the east, where permitting delays, labor shortages and depletion of lower cost reserves are all taking a toll.

Penn Virginia is positioned to take advantage of the strong commodity price environment. With the MLP increasing its reliance on fee-based revenue, Penn Virginia has covered the downside in energy prices without penalizing the upside.

At PVR, two main objectives for 2005 are to make a success of PVR Midstream and the coal handling joint venture. Acquiring additional coal reserves is also a priority. However, in central Appalachia, acquisitions are difficult to complete due to the very strong coal price environment which has raised sellers' expectations. PVR is also evaluating ideas in the Illinois basin, where the higher sulfur coals which have been out of favor are expected to be utilized as scrubbing becomes more widespread.

There should be numerous other opportunities to add to the midstream oil and gas platform being established with the Cantera acquisition. PVR's approach during 2005 will include trying to build out from the newly acquired midstream natural gas assets with "bolt on" acquisitions. Also, potential synergies between PVR and PVA's operations, especially in the east, will be explored. Finally, other stand-alone midstream oil and gas assets will be considered.

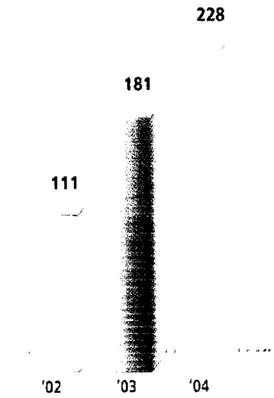
In addition to the favorable environment for energy prices, interest rates remain below historic averages, which is positive for MLPs such as PVR. Recent legislation has made it possible for mutual funds to make significant investments in MLPs, which is expected to increase access to capital and increase interest in the MLP sector.

By any measure 2004 was an excellent year. The Board and management are committed to continue the progress in 2005 and beyond. The hard work and dedication of Penn Virginia's employees make it all worthwhile.

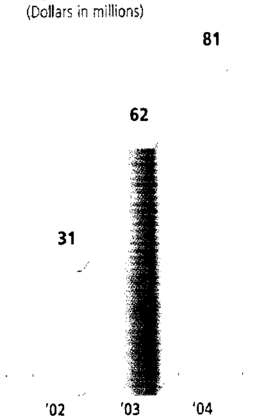
Robert Garrett
Chairman

A. James Dearlove
President and Chief Executive Officer

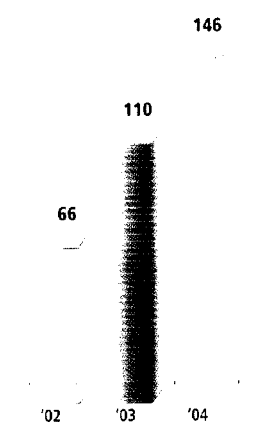
Total Revenues
(Dollars in millions)



Operating Income
(Dollars in millions)



Cash Flow From Operations
(Dollars in millions)



Penn Virginia's oil and gas strategy has been to establish a presence in nonconventional natural gas, particularly CBM; to build a significant inventory of predictable, low risk development prospects; and to selectively exploit exploration opportunities which could make a meaningful difference to the Company's production and reserve profile.

Nonconventional Natural Gas HCBM production up 91 percent to 2.1 Bcf and new ideas in CBM and shale were tested.

Long Term Development Projects East Texas Cotton Valley play started on 13,500 acres, 17 successful wells in 2004. Mississippi Selma Chalk development included 44 successful wells.

Exploration Successes in South Louisiana and South Texas and 2,500 miles of 3D seismic processed. Eastern exploration projects to find additional nonconventional reserves.

Penn Virginia's oil and gas strategy has been to establish a presence in nonconventional natural gas, particularly coalbed methane (CBM); to build a significant inventory of predictable, low risk development prospects; and to selectively exploit exploration opportunities which could make a meaningful difference to the Company's production and reserve profile. During 2004, real progress was made in each area.

Penn Virginia increased its oil and gas production by three percent over 2003 to a Company record 24.5 Bcfe. Production was negatively impacted by a curtailment on two natural gas pipelines serving the Company's assets in southern West Virginia, which particularly affected the HCBM program. The curtailments lasted from May through October and decreased 2004 production by approximately 1.1 Bcf.

Penn Virginia took steps to prevent future curtailments in order to accommodate the expected increases in gas volumes from the HCBM program. The Company constructed a 15-mile, 12-inch pipeline and acquired long-term firm transportation on Columbia Gas Transmission's pipeline system effective in the fourth quarter of 2004.

PennVirginia's total reserves at the end of 2004 were a Company record 354 Bcfe, an increase of ten percent over 2003. Approximately 89 percent of the Company's reserves at year-end 2004 were natural gas. Net of revisions, Penn Virginia added 57 Bcfe of proved reserves during 2004, replacing 233 percent of its 2004 production of 24.5 Bcfe.

During 2004, the Company drilled 20 gross (11 net) CBM wells using horizontal technology, a significant increase over the 12 gross HCBM wells drilled during 2003. HCBM production was 2.1 Bcf in 2004, up 91 percent from 1.1 Bcf produced in 2003. To date, the after tax returns on PVA's HCBM program exceed 50 percent. In 2005, Penn Virginia plans to spend approximately $21 million to drill 29 gross (15 net) HCBM wells in Appalachia and up to five gross CBM wells outside the basin. During 2004, a horizontal well was drilled in the Devonian shale and is currently under evaluation.

Early in 2004, the Company entered into a joint venture with GMX Resources, Inc. [NASDAQ:GMXR] to drill development wells in the North Carthage Field in east Texas. The wells are drilled in the Cotton Valley formation with the Travis Peak and Petit formations also present in some wells. Through the joint venture, the company has drilling rights on approximately 13,500 acres. Penn Virginia estimates 80 to 100 wells could ultimately be drilled on this acreage.

In the Company's Cotton Valley play in east Texas and north Louisiana, which includes the GMX joint venture, 23 gross (15.6 net) wells were drilled during 2004 with 100 percent success. Net Cotton Valley production for the year was 1.1 Bcfe, up from the 0.1 Bcfe produced in 2003. Penn Virginia has continued to expand its leasehold position in the Cotton Valley in east Texas. The 2005 budget includes approximately $27 million to drill 24 gross (17 net) wells in east Texas and north Louisiana.

Another important development area for Penn Virginia is the Selma Chalk formation in Mississippi. During 2004, 44 gross (43.6 net) Selma Chalk wells were drilled with 100 percent success.

Proved Reserves*
(Bcfe)

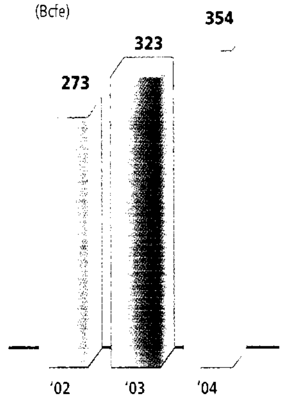
Appalachia	165
Mississippi	80
Gulf Coast	109
Totals	**354**

As of December 31, 2004

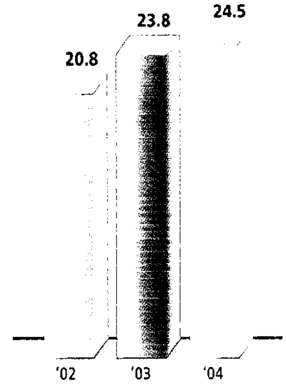
2004 Production
(Bcfe)

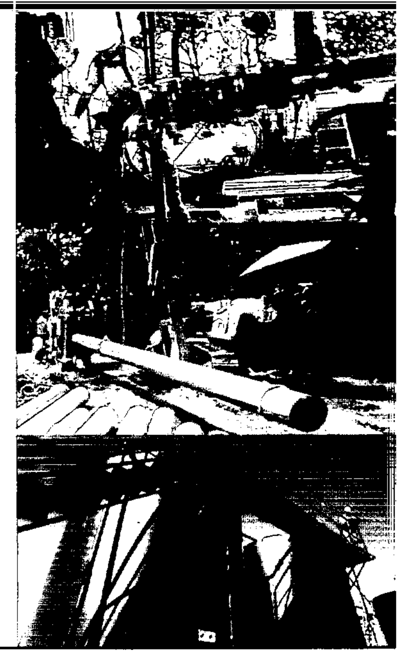
Appalachia	10.5
Mississippi	4.9
Gulf Coast	9.1
Totals	**24.5**

Proved Oil & Gas Reserves
(Bcfe)



Oil & Gas Production
(Bcfe)





Production from this play was 4.9 Bcfe in 2004, 29 percent higher than in 2003. The Company's 2005 budget includes approximately $23 million to drill 65 gross (64 net) wells in 2005.

During 2004, Penn Virginia drilled 11 gross and three net exploratory wells in the Gulf Coast region. Of the 11 wells, six were successful, three of which were located in south Louisiana and three were located in south Texas. During 2003 and 2004, the Company drilled eight successful exploratory wells in south Louisiana in ten attempts.

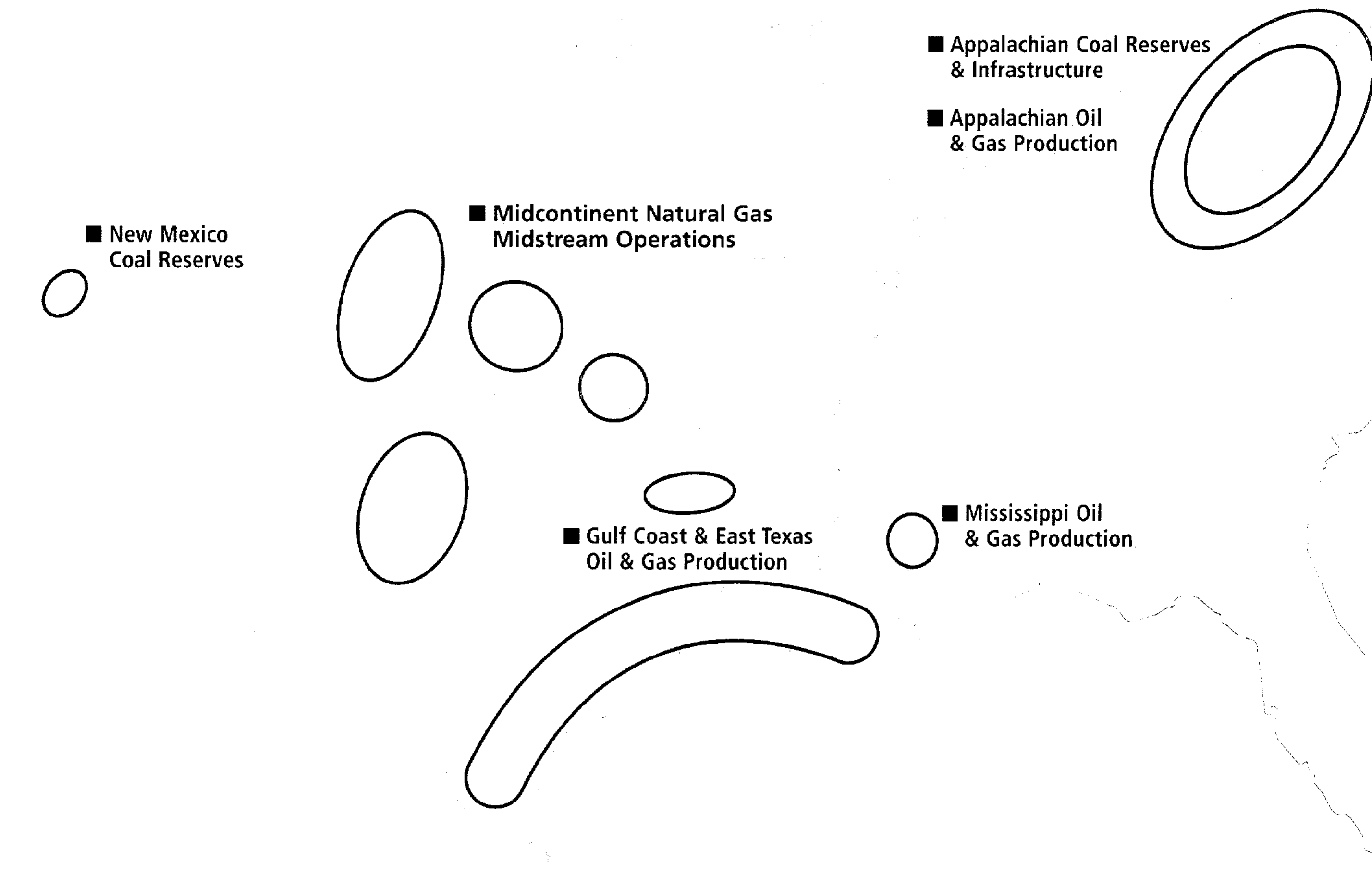
With a Gulf Coast 3D seismic database which exceeds 8,000 square miles, the Company continues to increase its internally generated prospect inventory in both south Louisiana and south Texas. In south Louisiana, the Company participated in its first prospect identified with a 100 square mile proprietary 3D program that was shot in 2003. The well, in which Penn Virginia has a 25 percent working interest, was drilled to a total depth of approximately 18,000 feet and found productive sands in two different intervals. The lower sand tested 6.6 Mmcf per day and 408 barrels of oil per day. The upper sand will be produced at a later date. Fourteen additional prospects have been identified within this 3D survey, two of which are expected to be drilled in 2005. After drilling a successful exploratory well and a development well in the Creole area in Cameron Parish in 2003, an additional exploratory well was drilled in 2004 which was a dry hole, and another exploratory well was drilling at year end 2004. Creole will continue to be an active area for the Company in 2005 with three exploratory wells planned. The Company has a 30 percent working interest in this field.

In south Texas, a successful Vicksburg exploratory well was drilled in the Kingsville Field in Kleberg County, in which Penn Virginia has a 25 percent working interest. In the Esperanza project area in Nueces County, in which the Company has a 33 percent working interest, two dry Vicksburg wells and one dry Frio well were drilled. The Vicksburg prospects were higher risk, high potential projects. The Company participated with a 20 percent working interest in a successful Frio exploratory well in Hidalgo County.

The Company's Board of Directors has approved a 2005 oil and gas capital expenditures budget of $146 million. Based on 2005 NYMEX prices of $6 per MMbtu for natural gas and $35 per barrel of oil, Penn Virginia expects to fund this capital budget using internally generated cash flows from oil and gas production. The Company also has a credit facility with a $150 million commitment which, as of January 31, 2005, had outstanding borrowings of $76 million. Additionally, to provide greater certainty of having sufficient operating cash flows to fund its oil and gas capital expenditures program, the Company has an active commodity price hedging program. As of January 31, 2005, the Company had natural gas hedges in place for 2005 covering approximately 25,800 MMbtu per day. These positions, primarily in the form of costless collars, provide average floor and ceiling prices of $5.25 and $7.40 per MMbtu, respectively, and cover approximately one third of the Company's expected 2005 natural gas production. The Company also had approximately 13,700 MMbtu per day of natural gas hedged for the first half of 2006 at average floor and ceiling prices of $5.20 and $9.60 respectively.

Penn Virginia Operating Regions

Penn Virginia expanded the scope of its natural resource operations during 2004 and early 2005 to include entry into the growing natural gas midstream sector through PVR's purchase of Cantera Resources Holdings LLC, which will operate as PVR Midstream LLC.



■ Penn Virginia Oil and Gas

Appalachia Conventional and CBM production; 165 Bcfe proved reserves and an estimated 400 drillable locations.

Mississippi Three fields in Selma Chalk, 80 Bcfe of proved reserves and an estimated 300 locations.

Gulf Coast On shore south Texas and south Louisiana; active development and exploration program; 109 Bcfe of proved reserves.

■ PVR Coal Land Management

Central Appalachia 446MM tons of high quality reserves; 61 mines served by two major railroads and inland river system.

Northern Appalachia 44MM tons of mid to high sulfur coal, principal lessee is Peabody Energy.

New Mexico 68MM tons of mid sulfur coal mined by Peabody and railed to several utilities.

■ PVR Midstream LLC (2005 PVR Acquisition)

Four systems — Beaver, Crescent, Hamlin and Arkoma 3,400 miles of gathering systems and three NGL processing plants with a total of 160 MMcfd capacity.

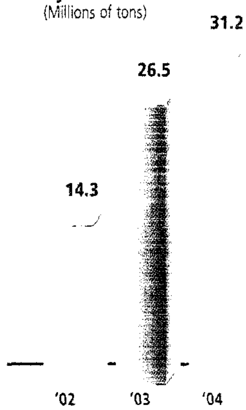
Year-End 2004 Reserves
(Millions of tons)

Central Appalachia	445.8
Northern Appalachia	44.5
New Mexico	67.8
Totals	**558.1**

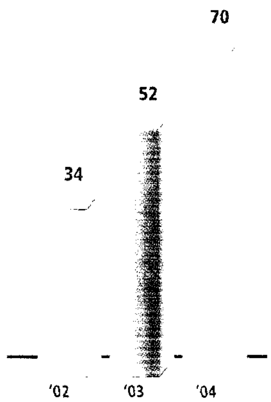
2004 Production
(Millions of tons)

Central Appalachia	20.1
Northern Appalachia	5.6
New Mexico	5.5
Totals	**31.2**

Coal Produced by PVR Lessees
(Millions of tons)



Coal Royalties*
(Dollars in millions)



*Includes minimum rental revenues

Penn Virginia is the general partner in Penn Virginia Resource Partners, L.P., (PVR) a coal royalty-based master limited partnership. As of December 31, 2004, Penn Virginia owned the general partner (GP) and approximately 43 percent of the Partnership units. During 2004, Penn Virginia received $17.3 million from the cash distributions paid by PVR to its unitholders.

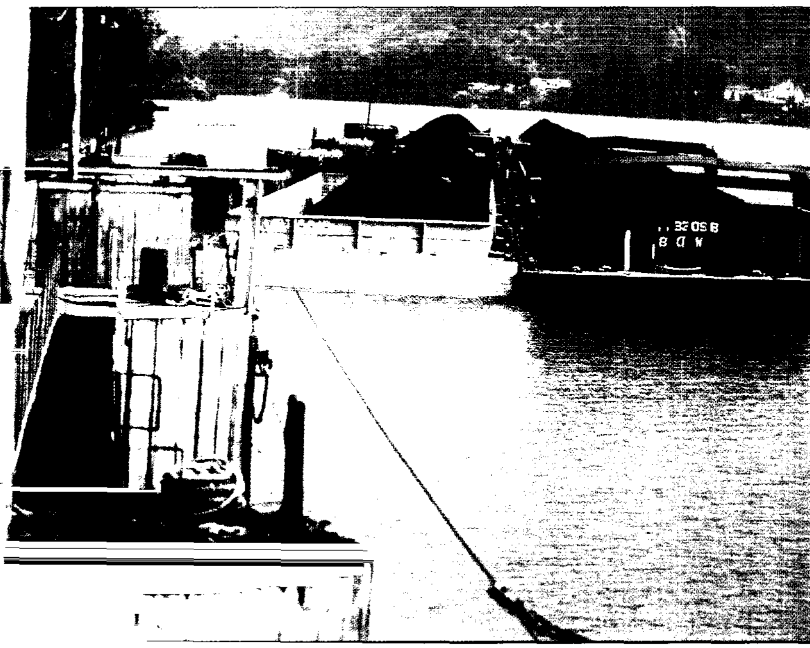
PVR increased its distributions to unitholders twice in 2004 to a quarterly payout of $0.5625 per unit effective with the distribution for the fourth quarter of 2004 payable in February 2005. As a result of moving above a quarterly distribution of $0.55 per unit Penn Virginia, as the GP, will receive 15 percent of the incremental cash flow over the $0.55 per unit distributed to the limited partners, up from two percent of the cash flow for distributions up to $0.55 per unit.

As of December 31, 2004, PVR owned or controlled an estimated 558 million tons of coal reserves including approximately 446 million tons in central Appalachia, 68 million tons in New Mexico and 44 million tons in northern Appalachia. The Partnership also owns a number of coal processing and loading facilities and approximately 114,500 surface acres of timberland.

During 2004 PVR's revenues were up 36 percent over 2003 to a record $76 million. Coal royalties in 2004 were $70 million, a 40 percent increase over 2003 and a record for the Partnership. Coal production from PVR's properties was a record 31.2 million tons, an 18 percent increase over 2003. Coal prices were very strong, especially in the east, where spot prices hovered around $60 per ton for much of the year.

More important than spot prices, many utilities are signing multi-year contracts with coal operators to purchase coal at over $40 per ton. These prices are dramatic increases over contract prices from 2002 or early 2003. The significance is the new contracts tend to lock in the higher prices for a period of time providing a degree of certainty to the industry.

PVR remains committed to growth in the coal royalty and related businesses. However, one negative effect of the high price environment was to limit the opportunities to complete accretive acquisitions of coal reserves. PVR has evaluated and continues to review a number of coal reserve prospects, however, there is little appeal to overpaying.



Through its ownership of 7.8 million limited partner units and the general partner of PVR, Penn Virginia Corporation received cash distributions of approximately $17.3 million from PVR during 2004.

The Partnership was able to take advantage of another growth opportunity in 2004 by acquiring from affiliates of Massey Energy Company for $28.4 million in July 2004, a 50 percent interest in a joint venture formed to own and operate end-user coal handling facilities. The joint venture is pursuing additional projects to build and operate coal handling facilities for end-users.

A stated objective of PVR has been to gain entry to the midstream oil and gas business. Although highly competitive, this industry with its long-lived, fee-based assets is the traditional home of the MLPs. Penn Virginia's oil and gas company has its own midstream (gathering) assets and the requisite in-house knowledge to manage a midstream business. In addition, during 2003 PVR added a core group of highly experienced midstream staff to evaluate and manage oil and gas gathering and processing assets.

The Cantera acquisition will achieve the goal of establishing a midstream oil and gas presence and is important for several reasons. It is expected to be immediately accretive to distributable cash flow and a significant percentage of its revenues are fee-based, thus highly compatible with PVR's MLP structure. Also, Cantera's seasoned commercial and operating staff, when combined with the PVR midstream group forms a solid team to oversee the future growth of the PVR midstream segment.

Cantera's assets include approximately 3,400 miles of gas gathering pipelines that supply three natural gas processing plants, which have 160 million cubic feet per day of capacity. Revenues are derived primarily from the sharing of sales proceeds of natural gas and natural gas liquids under contracts with natural gas producers and from fees charged for the gathering and treating of natural gas and other related services. The Cantera acquisition, which will operate as PVR Midstream LLC, is expected to generate $25 to $28 million of cash flow from operations in the first twelve months following closing.

As part of its coal land management business, PVR owns approximately 167 million board feet of standing timber. The Partnership typically sells cutting rights to various contractors who usually cut in advance of a mining project. Timber revenues in 2004 were $0.7 million, down from $1.0 million in 2003, as PVR sold only the timber necessary to accommodate its lessees' mining operations.

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, 2004

Commission File Number 0-753

PENN VIRGINIA CORPORATION

Incorporated in VIRGINIA	I.R.S. Employer Identification Number 23-1184320

Three Radnor Corporate Center, Suite 230
100 Matsonford Road
Radnor, PA 19087

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 whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ 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 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 registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☒ No ☐

The aggregate market value of common stock held by non-affiliates of the registrant was $659,289,014 as of June 30, 2004 (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, but excluding any institutional shareholders owning more than ten percent of the Registrant's Common Stock.

As of March 1, 2005, 18,497,131 shares of common stock of the registrant were issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

	Part Into Which Incorporated
(1) Proxy Statement for Annual Shareholders Meeting on May 3, 2005	Part III

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

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PART I

Item 1—*Business*

General

Penn Virginia Corporation ("Penn Virginia" or the "Company") is a Virginia corporation founded in 1882 whose common units are traded on the New York Stock Exchange under the symbol PVA. We are engaged in the exploration, development and production of crude oil and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. We also collect royalties on various oil and gas properties in which we own a mineral fee interest. At December 31, 2004, we had proved reserves of approximately 6.3 million barrels of oil and condensate and 316 billion cubic feet ("Bcf") of natural gas, or 354 billion cubic feet equivalent ("Bcfe").

We are also indirectly involved in the businesses engaged in by Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"), a Delaware limited partnership whose common units are traded on the New York Stock Exchange under the symbol PVR. The Partnership owns and manages coal properties. The Partnership does not operate any mines, but rather leases its coal reserves to various mining operators in exchange for royalty payments. In managing its properties, PVR actively works with its lessees to develop efficient methods to exploit reserves and to maximize production from properties. Additionally, the Partnership provides fee-based coal preparation and transloading facilities to some of its lessees and to other third party industrial end-users. The Partnership also generates revenues from the sale of standing timber on its properties. On March 3, 2005, the Partnership acquired a midstream gas gathering and processing business with locations in the mid-continent area of Oklahoma and the Texas panhandle from Cantera Natural Gas, LLC. See further discussion of this acquisition in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions—Coal Royalty and Land Management—Midstream Oil and Gas."

Our wholly owned subsidiary, Penn Virginia Resource GP, LLC, a Delaware limited liability company, serves as general partner of the Partnership. As of December 31, 2004, we owned approximately 44.5 percent of the Partnership, consisting of a two percent general partner interest and a 43 percent limited partner interest. As part of our ownership of PVR's general partner, we also own the rights, referred to as "incentive distribution rights," to receive an increasing percentage of the Partnership's quarterly distributions of available cash from operating surplus after certain levels of cash distributions have been achieved. See Item 1, "Business—Corporate and Other," for more information on incentive distribution rights.

Financial Information and Segments

We operate in two primary business segments. We are in the crude oil and natural gas exploration and production business and, through our interests in PVR, we are in the coal royalty and land management and coal services businesses. For financial statement purposes, the assets, liabilities and earnings of PVR are included in our consolidated financial statements, with the public unitholders' ownership interest reflected as a minority interest. See Note 21, "Segment Information," in the Notes to Consolidated Financial Statements for financial information concerning our business segments. In March 2005, we entered a third business segment when PVR acquired a natural gas gathering and processing business. See further discussion of this acquisition in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions—Coal Royalty and Land Management—Midstream Oil and Gas."

Oil and Gas Operations

General

Our oil and gas properties are located primarily in the eastern and onshore Gulf Coast areas of the United States. At December 31, 2004, we had 354 Bcfe of proved reserves, of which 89 percent was natural gas. Seventy-four percent of those proved reserves were proved developed reserves. During 2004, 396 thousand barrels of oil and condensate and 22.1 Bcf of natural gas, net to our interest, were produced from continuing operations compared with 625 thousand barrels and 20.1 Bcf in 2003. We received average prices of $33.75 and $26.91 per barrel for crude oil and $6.27 and $5.31 per thousand cubic feet ("Mcf") for natural gas in 2004 and 2003, respectively. We also drilled 152 gross (98.5 net) wells in 2004, of which 135 gross (90.0 net) wells were development and 17 gross (8.5 net) wells were exploratory. A total of one development well (0.3 net) and seven gross (4.4 net) exploratory wells were not successful and three gross (2.6 net) exploratory wells were under evaluation at December 31, 2004.

Transportation

The majority of our natural gas production is transported to market on five major pipeline or transmission systems. NiSource Inc., Crosstex Energy Services LTD, Dominion Transmission, Inc., Duke Energy Corporation and Gulf South Pipeline Company, LP, transported 22 percent, 20 percent, 11 percent, 11 percent and 10 percent, respectively, of our 2004 natural gas production. The remainder was divided among several pipeline companies in Texas, Louisiana and West Virginia. In almost all cases, our natural gas is sold at interconnects with transmission pipelines. For additional information, see Item 1, "Business—Risks Associated with Business Activities—Oil and Gas—Transportation."

In 2004, we entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to 10 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. We have an agreement to sell to a third party a portion of our capacity available under the firm transportation commitments. We also sell excess capacity to third parties on a month-by-month basis.

Marketing and Hedging

We generally sell our natural gas using spot market and short-term fixed price physical contracts. For the year ended December 31, 2004, two customers of the oil and gas segment, Dominion Transmission, Inc. and Crosstex Energy Services LTD, accounted for approximately 14 percent and 12 percent, respectively, of our total revenues.

From time to time, we enter into commodity derivative contracts or fixed price physical contracts to mitigate the risk associated with the volatility of natural gas and crude oil prices. Recently, we have utilized swaps and costless collars in connection with our hedging activities. Gains and losses from hedging activities are included in revenues when the hedged production is sold. We recognized losses on settled hedging activities of $5.9 million, $6.1 million, and $1.1 million in 2004, 2003, and 2002, respectively. In 2004, we hedged approximately 36 percent of our natural gas production at an average NYMEX Henry Hub floor price of $3.93 per MMbtu and a ceiling price of $5.99 per MMbtu for costless collars, and an average $4.70 per MMbtu for swaps. For crude oil, we hedged approximately 45 percent of our 2004 crude oil production using fixed price swaps with an average price of $29.78 per barrel. See Note 10, "Hedging Activities," in the Notes to Consolidated Financial Statements for information about our price risk management positions for future periods.

Coal Royalty and Land Management Operations

General

At December 31, 2004, the Partnership's properties contained approximately 558 million tons of proven and probable coal reserves located on 241,000 acres in Virginia, West Virginia, New Mexico and eastern Kentucky. The Partnership does not operate coal mines. The Partnership earns coal royalty revenues, based on long-term lease agreements, from 29 coal mining operators actively mining under 55 separate leases at 65 mines. Approximately 79 percent of PVR's coal royalty revenues earned in 2004 and 72 percent of those earned in 2003 were derived under leases providing that PVR receives the higher of a percentage of gross sales price or a fixed price per ton of coal sold ("market-sensitive leases"), with pre-established minimum monthly or annual payments. The balance of royalty revenues earned by PVR during 2004 and 2003 was derived under leases containing fixed royalty rates per ton of coal mined and sold ("fixed rate leases"). The royalty rates under those leases escalate annually with pre-established monthly minimums (see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions—Coal Royalty and Land Management" regarding the Peabody Acquisition).

Coal Royalties

The Partnership's lessees mined approximately 31.2 million tons of coal in 2004 from PVR's properties and paid an average royalty of $2.23 per ton, compared with approximately 26.5 million tons mined in 2003 at an average royalty of $1.90 per ton. In 2004, PVR's lessees mined approximately 20.9 million tons of coal on properties with market-sensitive leases, with an average royalty of $2.64 per ton, compared with 15.9 million tons of coal and an average royalty of $2.28 per ton in 2003. Coal mined from fixed rate leases during 2004 totaled 10.3 million tons at an average royalty rate of $1.41 per ton, compared with 10.6 million tons and an average royalty rate of $1.33 per ton in 2003.

The Partnership also harvests timber in advance of lessee mining to prevent loss of the resource. Timber is sold as individual parcels in competitive bid sales or on a contract basis, where PVR pays independent contractors to harvest timber while PVR directly markets the product. The Partnership sold approximately 2.6 MMbf in 2004, compared with 5.3 MMbf in 2003.

Coal Services

The Partnership generates coal services revenues from fees charged to lessees for use of the Partnership's coal preparation and transloading facilities. The majority of these fees have been generated by the Partnership's unit train loadout facility located on its Wise property. This facility accommodates up to 108-car unit trains, which can be loaded in approximately four hours. Lessees utilize the unit train loadout facility to reduce delivery costs incurred by their customers. The Partnership also earns revenues through its joint venture with Massey Energy Company, which owns and operates coal handling facilities used by third party industrial end-users. The Partnership recognized $3.4 million in coal services revenues in 2004, compared to $2.1 million in 2003. Such amounts are reported as other revenues in the Consolidated Statements of Income.

Partnership Distributions

Cash Distributions. The Partnership paid cash distributions of $2.12 per common and subordinated unit during the year ended December 31, 2004. In the first quarter of 2005, the Partnership made a quarterly distribution of $0.5625 ($2.25 annualized). For the remainder of 2005, the Partnership expects to make quarterly distributions of $0.62 ($2.48 annualized) or more per common and subordinated unit.

We are entitled, through our wholly owned subsidiaries, to receive certain cash distributions payable with respect to the subordinated and common units of PVR held by such subsidiaries as well as certain cash distributions payable with respect to incentive distribution rights held by our general partner subsidiary. The Company received distributions from PVR of $17.3 million and $16.8 million in 2004 and 2003, respectively.

Subordination Period. During the subordination period, which we describe below, PVR's common units have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution, plus arrearages in the payment of any minimum quarterly distribution from prior quarters, before any distributions of available cash from operating surplus can be made on the subordinated units. The minimum quarterly distribution is $0.50 per unit ($2.00 annualized).

Definition of Subordination Period. The subordination period began on October 30, 2001, and will continue until the first day of any quarter beginning after September 30, 2006, in which each of the following events occur:

- distributions of available cash from operating surplus on each of the common units and the subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the adjusted operating surplus generated during each of the three immediately preceding, non-overlapping four-quarter periods equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the two percent general partner interest during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early Conversion of Subordinated Units. Before the end of the subordination period, 50 percent of the subordinated units, or up to 3,824,940 subordinated units were or will be eligible for conversion into common units on a one-for-one basis immediately after the distribution of available cash to partners in respect of any quarter ending on or after:

- September 30, 2004 with respect to 25 percent of the subordinated units; and
- September 30, 2005 with respect to 25 percent of the subordinated units.

The early conversions occur if at the end of the applicable quarter each of the following three tests are met:

- distributions of available cash from operating surplus on each common unit and subordinated unit equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the adjusted operating surplus generated during each of the three immediately preceding, non-overlapping four-quarter periods equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the two percent general partner interest during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Because PVR met these financial tests at September 30, 2004, 25 percent of the subordinated units converted to common units on November 12, 2004.

Incentive Distribution Rights. Our wholly owned subsidiary is the general partner of PVR and, as such, holds certain incentive distribution rights which represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the Partnership has paid minimum quarterly distributions and certain target distribution levels have been achieved. The incentive distributions rights are payable as follows:

If for any quarter:

- PVR has distributed available cash from operating surplus to its common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- PVR has distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, PVR will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner subsidiary in the following manner:

- First, 98 percent to all unitholders, and two percent to the general partner, until each unitholder has received a total of $0.55 per unit for that quarter;

- Second, 85 percent to all unitholders, and 15 percent to the general partner, until each unitholder has received a total of $0.65 per unit for that quarter;
- Third, 75 percent to all unitholders, and 25 percent to the general partner, until each unitholder has received a total of $0.75 per unit for that quarter; and
- Thereafter, 50 percent to all unitholders and 50 percent to the general partner.

In each case, the amount of the target distribution set forth above is exclusive of any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution on the common units. In conjunction with the acquisition of certain reserves from Peabody Energy Corporation ("Peabody") in 2002, and if PVR purchases additional assets from Peabody in the future, our general partner subsidiary has issued a special membership interest which entitles Peabody to receive increased percentages, starting at zero and increasing up to 40 percent, of payments PVR makes to our general partner subsidiary with respect to incentive distribution rights. PVR has not purchased any additional assets from Peabody.

Risks Associated with Business Activities – Oil and Gas

Competition

The oil and natural gas industry is very competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Our competitive position depends on our geological, geophysical and engineering expertise, our financial resources, our ability to develop properties and our ability to select, acquire and develop proved reserves. We compete with a substantial number of other companies that have greater financial and operational resources. 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. We also compete with major and independent 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. We compete with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time.

Price Volatility

Historically, natural gas and crude oil prices have been volatile. These prices rise and fall based on changes in market demand and changes in the political, regulatory and economic climate and other factors that affect commodities markets that are generally outside of our control. Some of our projections and estimates are based on assumptions as to the future prices of natural gas and crude oil. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future may differ from our estimates. Any substantial or extended decline in the actual prices of natural gas or crude oil could have a material adverse effect on the Company's financial position and results of operations (including reduced cash flow and borrowing capacity), the quantities of natural gas and crude oil reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

Drilling and Operating Risks

Our drilling operations are subject to various risks common in the industry, including cratering, explosions, fires and uncontrollable flows of oil, gas or well fluids. Our drilling operations are also subject to the risk that no commercially productive natural gas or oil reserves will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including drilling conditions, high pressure or irregularities in formations, equipment failures or accidents and adverse weather conditions.

Transportation

We transport our natural gas to market on various gathering and transmission pipeline systems owned by third parties. Gathering fees are primarily paid by the purchaser of the natural gas. The majority of natural gas sales contracts are one year or less in duration and contain relevant monthly index pricing provisions. Interruptible gathering rates have increased over the years as pipelines have implemented the mandatory unbundling of gathering services (Federal Energy Regulatory Commission Order 636) from other transportation services. Production could be adversely affected by disruptions or curtailments of the operations of pipelines for maintenance or replacement as transportation options are limited.

Regulation

State Regulatory Matters. Various aspects of our oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas. These provisions include the permitting for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, provisions relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. The effect of these regulations is to limit the amounts of crude oil and natural gas we can produce from our wells and to limit the number of wells or the locations at which we can drill.

Federal Energy Regulatory Commission. The Federal Energy Regulatory Commission ("FERC") regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). In the past, the Federal government has regulated the prices at which oil and gas could be sold. The Natural Gas Wellhead Decontrol Act of 1989 (the "Decontrol Act") removed all NGA and NGPA price and nonprice controls affecting producers' wellhead sales of natural gas effective January 1, 1993. While sales by producers of their own natural gas production and all sales of crude oil, condensate and natural gas liquids can currently be made at market prices, Congress could reenact price controls in the future.

Commencing in April 1992, the FERC issued Order Nos. 636, 636-A, 636-B and 636-C ("Order No. 636"), which require interstate pipelines to provide transportation separate, or "unbundled," from the pipelines' sale of gas. Also, Order No. 636 requires pipelines to provide open-access transportation on a basis that is equal for all gas supplies. Although Order No. 636 does not directly regulate gas producers like Penn Virginia, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. In particular, the FERC has issued Order Nos. 637, 637-A and 637-B which, among other things, (i) permit pipelines to charge different maximum cost-based rates for peak and off-peak periods, (ii) encourage auctions for pipeline capacity, (iii) require pipelines to implement imbalance management services, and (iv) restrict the ability of pipelines to impose penalties for imbalances, overruns, and non-compliance with operational flow orders. In addition, the FERC has regulations in place that govern the procedure for obtaining authorization to construct new pipeline facilities and has issued a policy statement, which it largely affirmed in a recent order on rehearing, establishing a presumption in favor of requiring owners of newly constructed pipeline facilities to charge rates based on the incremental costs associated with such new pipeline facilities.

While any additional FERC action on these matters would affect us only indirectly, these changes are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC will take on these matters, nor can we predict whether the FERC's actions will achieve its stated goal of increasing competition in natural gas markets. However, we do not believe that we will be treated materially differently than other natural gas producers and markets with which we compete.

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 closure of inactive pits and plugging of abandoned wells. 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 adverse impact on us. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

Risks Associated with Business Activities—Coal Royalty and Land Management

Partnership Distributions

Although the Partnership expects to make quarterly cash distributions of $0.62 or more per common unit, it can only do so to the extent it has sufficient cash from operations after payment of fees and expenses. In addition, quarterly distributions are payable on our subordinated units only after each common unit has received a distribution of $0.50 plus any arrearages due from prior quarters. Incentive distributions are payable to our general partner subsidiary after cash distributions per unit exceed $0.55 in any quarter. The Partnership's revenues and its ability to make quarterly and incentive distributions are subject to several risks, including those described below.

Competition

The coal industry is intensely competitive primarily as a result of the existence of numerous producers. The Partnership's lessees compete with coal producers in various regions of the U.S. for domestic sales. The industry has undergone significant consolidation, and some of the competitors of the Partnership's lessees have significantly larger financial and operating resources than most of the Partnership's lessees. The Partnership's lessees primarily compete with both large and small producers in Appalachia as well as in the western United States. The lessees compete on the basis of coal price at the mine, coal quality (including sulfur content), transportation cost from the mine to the customer and the reliability of supply. Continued demand for the Partnership's coal and the prices that the Partnership's lessees obtain are also affected by demand for electricity, demand for metallurgical coal, access to transportation, environmental and government regulations, technological developments and the availability and price of alternative fuel supplies, including nuclear, natural gas, oil and hydroelectric power. Demand for the Partnership's low sulfur coal and the prices the Partnership's lessees will be able to obtain for it will also be affected by the price and availability of high sulfur coal, which can be marketed in tandem with emissions allowances which permit the high sulfur coal to meet federal Clean Air Act requirements.

Operating Risks

General Regulation. The Partnership's lessees are obligated to conduct mining operations in compliance with all applicable federal, state and local laws and regulations. These laws and regulations include matters involving the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, plant and wildlife protection, limitations on land use, storage of petroleum products and substances which are regarded as hazardous under applicable laws, and management of electrical equipment containing polychlorinated biphenyls, or PCBs. Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, we do not believe violations by the Partnership's lessees can be eliminated completely. However, none of the violations to date, or the monetary penalties assessed, have been material to the Partnership or, to our knowledge, to the Partnership's lessees. We do not currently expect that future compliance will have a material adverse effect on us or the Partnership.

While it is not possible to quantify the costs of compliance by the Partnership's lessees with all applicable federal and state laws, those costs have been and are expected to continue to be significant. The lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. The Partnership does not accrue for such costs because its lessees are contractually liable for all costs relating to their mining operations, including the costs of reclamation and mine closure. However, the Partnership does require some smaller lessees to deposit into escrow certain funds for reclamation and mine closure costs or post performance bonds for these costs. Although the lessees typically accrue adequate amounts for these costs, their future operating results would be adversely affected if they later determined these accruals to be insufficient. Compliance with these laws has substantially increased the cost of coal mining for all domestic coal producers.

In addition, the electric utility industry, which is the most significant end-user of coal, is subject to extensive regulation regarding the environmental impact of its power generation activities which could affect demand for coal mined by the Partnership's lessees. The possibility exists that new legislation or regulations may be adopted which may have a significant impact on the mining operations of the Partnership's lessees or their customers' ability to use coal and may require the Partnership, its lessees or their customers to change operations significantly or incur substantial costs.

Certain Regulatory and Legal Matters

Clean Air Act. The Clean Air Act affects the end-users of coal and could significantly affect the demand for the Partnership's coal and reduce the Partnership's coal royalty revenues. The Clean Air Act and corresponding state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides and other compounds emitted from industrial boilers and power plants, including those that use the Partnership's coal. These regulations together constitute a significant burden on coal customers and stricter regulation could further adversely impact the demand for and price of the Partnership's coal, resulting in lower coal royalty revenues.

In July 1997, the U.S. Environmental Protection Agency ("EPA") adopted more stringent ambient air quality standards for particulate matter and ozone. Particulate matter includes small particles that are emitted during the combustion process. Nitrogen oxides are naturally occurring byproducts of coal combustion that lead to the formation of ozone. In a February 2001 decision, the U.S. Supreme Court largely upheld the EPA's position, although it remanded the EPA's ozone implementation policy for further consideration. Details regarding the new particulate standard itself are still subject to judicial challenge. These ozone restrictions will require electric power generators to further reduce nitrogen oxide emissions. Further reduction in the amount of particulate matter that may be emitted by power plants could also result in reduced coal consumption by electric power generators. Future regulations regarding ozone, particulate matter and other ambient air standards could restrict the market for coal and the development of new mines by the Partnership's lessees. This, in turn, may result in decreased production by the Partnership's lessees and a corresponding decrease in the Partnership's coal royalty revenues. These decreases could adversely affect the distributions we receive from the Partnership.

The Clean Air Act also imposes standards on sources of hazardous air pollutants. These standards have not yet been extended to coal mining operations. However, on January 30, 2004, the EPA proposed regulations to control emissions of mercury, a hazardous air pollutant, from power plants that combust coal, as well as nitrogen oxides and sulfur dioxide, which are also power plant pollutants, in 29 states. Like other environmental regulations, these standards and future standards could result in a decreased demand for coal.

In addition to EPA proposals, various members of Congress have proposed so-called multi-pollutant bills, which could regulate nitrogen oxides, sulfur dioxide and other emissions, including carbon dioxide, from power plants that combust coal, and the regulation of greenhouse gases that might contribute to global warming could occur either pursuant to regulatory changes under the Clean Air Act, regulations by states or future U.S. treaty obligations. Moreover, a number of states have proposed to regulate emissions of mercury and are proposing in some cases to set limits on emissions of carbon dioxide and in other cases to implement a cap and trade program to reduce emissions of carbon dioxide. The uncertainty about the regulation of mercury and carbon dioxide in particular is substantial, as a number of lawsuits have been filed challenging both proposals by EPA for a cap-and trade program for mercury and EPA's conclusion that carbon dioxide is not covered by the Clean Air Act. While the details of proposed initiatives to regulate air emissions vary, and the outcome of legislative, regulatory and judicial disputes cannot be predicted, there is certainly a movement toward increased regulation of emissions of pollutants from the combustion of fossil fuels, including coal. If such initiatives are enacted into law, power plants could choose to shift away from coal as a fuel source to meet these requirements.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977 ("SMCRA") and similar state statutes impose on mine operators the responsibility of restoring the land to its original state or compensating the landowner for types of damages occurring as a result of mining operations, and require mine operators to post performance bonds to ensure compliance with any reclamation obligations. Regulatory authorities may attempt to assign the liabilities of the Partnership's lessees to the Partnership if any of the lessees are not financially capable of fulfilling those obligations. In conjunction with mining the property, the Partnership's lessees are contractually obligated under the terms of their leases to comply with all laws, including SMCRA, with obligations including reclamation and restoration of the mined areas by grading, shaping and reseeding the soil. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan.

CERCLA. The Partnership could become liable under federal and state Superfund and waste management statutes if its lessees are unable to pay environmental cleanup costs. The Comprehensive Environmental Response, Compensation and Liability Act, known as CERCLA or "Superfund," and similar state laws create liabilities for the investigation and remediation of releases and threatened releases of hazardous substances to the environment and damages to natural resources. As a landowner, the Partnership is potentially subject to liability for these investigation and remediation obligations.

Surface Mining Valley Fills. Over the course of the last several years, opponents of surface mining have filed three lawsuits challenging the legality of permits authorizing the construction of valley fills for the disposal of coal mining overburden under federal and state laws applicable to surface mining activities. Although two of these challenges were successful in the United States District Court for the southern District of West Virginia (the "District Court"), the United States Court of Appeals for the Fourth Circuit overturned both of those decisions in *Bragg v. Robertson* in 2001 and in *Kentuckians For The Commonwealth v. Rivenburgh* in 2003.

A ruling on July 8, 2004, which was made by the District Court in connection with a third lawsuit, may impair the Partnership's lessees' ability to obtain permits that are needed to conduct surface mining operations. In this case, *Ohio Valley Environmental Coalition v. Bulen*, the District Court determined that the Army Corps of Engineers (the "Corps") violated the Clean Water Act ("CWA") and other federal statutes when it issued Nationwide Permit 21 ("NWP21"). This ruling is currently on appeal, but no decision has been issued by the appeals court as of yet.

In January of 2005, Kentucky Riverkeepers, Inc. and several other groups filed suit in federal district court in Kentucky challenging the legality of NWP21, and seeking to enjoin the Corps from issuing any general permits thereunder for fills associated with coal mining in Kentucky. Should the district court hearing this case follow the reasoning of *Ohio Valley Environmental Coalition v. Bulen* and similarly enjoin the Corps from issuing general permits for coal mining under that general permit, companies seeking permits under Section 404 of the CWA in Kentucky may have to file for individual permits that may result in increases in coal mining costs. The Partnership does not have a substantial amount of reserves in Kentucky and does not expect that its lessees would be affected significantly by the outcome in this case.

West Virginia Anti-degradation Policy. A September 2003 decision by the District Court in *Ohio Valley Environmental Coalition v. Whitman* vacated the EPA's approval of the State of West Virginia's anti-degradation implementation policy, which applies to discharges into waters that have been designated as high quality waters by the State. The District Court determined that the State's policy did not comply with the requirements of the CWA. The West Virginia anti-degradation policy had included a number of exceptions, including one for parties holding general CWA permits, from anti-degradation review requirements. The District Court ruled that this exemption and certain other provisions of the West Virginia anti-degradation policy were not consistent with the requirements of the CWA. The EPA Region III subsequently sent a letter to the West Virginia Department of Environmental Protection approving portions of its plan, denying approval of other portions pending further study, and recommending the removal of other provisions of the plan. The West Virginia Department of Environmental Protection is reportedly reviewing this letter. The Partnership's lessees seek permits to discharge into high quality waters under a new policy which does not include such an exception. As a result of this decision, permit applications will likely be required to undergo the public and intergovernmental scrutiny associated with an anti-degradation review, which may either delay the issuance or reissuance of CWA permits, require the use of more costly control measures or lead to the denial of these permits. The delay, denial or added costs of complying with these permits may increase the costs of coal production, potentially reducing PVR's royalty revenues and adversely affecting our Partnership distributions.

Mine Health and Safety Laws. The operations of the Partnership's lessees are subject to stringent health and safety standards that have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. However, since the Partnership does not operate any mines and does not employ any coal miners, the Partnership is not subject to such laws and regulations. The Mine Health and Safety Act of 1969 resulted in increased operating costs and reduced productivity. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive health and safety standards on all mining operations. In addition, as part of the Mine Health and Safety Acts of 1969 and 1977, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung or pneumoconiosis and to some beneficiaries of miners who have died from this disease.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, the Partnership's lessees may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including the Partnership's lessees, must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically, lessees submit the necessary permit applications between 12 and 24 months before they plan to begin mining a new area. In the Partnership's experience, permits generally are approved within 12 months after a completed application is submitted. In the past, lessees have generally obtained their mining permits without significant delay. The Partnership's lessees have obtained or applied for permits to mine a majority of the reserves that are currently planned to be mined by them over the next five years. The Partnership's lessees are also in the planning phase for obtaining permits for the additional reserves planned to be mined over the following five years. However, there are no assurances that they will not experience difficulty in obtaining mining permits in the future.

Timber Regulations. The Partnership's timber operations are subject to federal, state and local laws and regulations, including those related to the environment, protection of endangered species, foresting activities and health and safety. The Partnership believes it is managing its timberlands in substantial compliance with applicable federal and state regulations.

See also Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," for a discussion of interest rate risk.

Employees

We had 120 employees at December 31, 2004, including 32 employees who directly provide services for PVR through its general partner. We consider our relations with our employees to be favorable.

Available Information

The Company's Internet address is www.pennvirginia.com. We make available free of charge on or through our Internet website our Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics and the charters of each of our Audit Committee, Nominating and Governance Committee, Compensation and Benefits Committee and Oil and Gas Committee. We also make available free of charge on or through our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

Executive Officers of the Company

The following table sets forth information concerning our executive officers. Each officer is elected annually by the Board of Directors and serves at the pleasure of the Board of Directors.

Name	Age	Position with the Company
A. James Dearlove	57	President and Chief Executive Officer
Frank A. Pici	49	Executive Vice President and Chief Financial Officer
H. Baird Whitehead	54	Executive Vice President
Keith D. Horton	51	Executive Vice President
Nancy M. Snyder	52	Senior Vice President, General Counsel and Secretary
Ronald K. Page	54	Vice President, Corporate Development

A. James Dearlove—Mr. Dearlove has served in various capacities with the Company since 1977, including as President and Chief Executive Officer and a Director of the Company since May 1996, President and Chief Operating Officer of the Company from 1994 to May 1996, Senior Vice President of the Company from 1992 to

1994 and Vice President of the Company from 1986 to 1992. He is also Chief Executive Officer and Chairman of the Board of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P. He also serves as director of the National Council of Coal Lessors.

Frank A. Pici—Mr. Pici is the Executive Vice President and Chief Financial Officer of the Company, which he joined in September 2001. Mr. Pici is also the Vice President and Chief Financial Officer and a Director of Penn Virginia Resource, GP LLC. From 1996 to 2001, Mr. Pici served as Vice President – Finance and Chief Financial Officer of Mariner Energy, Inc., an oil and gas exploration and production company. Prior to 1996, he served in various capacities with Cabot Oil & Gas Corporation, including Corporate Controller from 1994 to 1996, Director, Internal Audit from 1992 to 1994, and Region Accounting Manager from 1989 to 1992. From 1982 to 1989, he held financial management positions with companies in the oil and gas and coal industries.

H. Baird Whitehead—Mr. Whitehead is an Executive Vice President of the Company, which he joined in January 2001. Prior to joining Penn Virginia, Mr. Whitehead served in various positions with Cabot Oil & Gas Corporation. From 1998 to 2001, he served as Senior Vice President during which time he oversaw Cabot's drilling, production, and exploration activity in the Appalachia, Rocky Mountains, Mid-Continent and the Texas and Louisiana Gulf Coast areas. From 1992 to 1998, he was Vice President and Regional Manager of Cabot's Appalachian business unit and from 1989 to 1992, he was Vice President and Regional Manager of Cabot's Anadarko business unit. From 1987 to 1989, he served as Vice President of Engineering for Cabot. From 1972 to 1987, he held various engineering and supervisory positions with Texaco, Columbia Gas Transmission and Cabot.

Keith D. Horton—Mr. Horton has served in various capacities with the Company since 1981, including Executive Vice President and a Director of the Company since December 2000, Vice President—Eastern Operations of the Company from February 1999 to December 2000, President of Penn Virginia Coal Company from February 1996 to October 2001, Vice President of Penn Virginia Coal Company from March 1994 to February 1996, Vice President from January 1990 to December 1998, and Manager, Coal Operations from July 1982 to December 1989, of Penn Virginia Resources Corporation. He is also the President and Chief Operating Officer and a Director of Penn Virginia Resource, GP LLC. Additionally, Mr. Horton serves as a director of the Virginia Mining Association, Powell River Project and Eastern Coal Council.

Nancy M. Snyder—Ms. Snyder has served as Senior Vice President of the Company since February 2003 and as General Counsel and Corporate Secretary of the Company since 1997. She was a Vice President of the Company from December 2000 to February 2003. Ms. Snyder is also the Vice President, General Counsel and a Director of Penn Virginia Resource GP, LLC. From 1993 to 1997, Ms. Snyder was a solo practitioner representing clients generally in connection with mergers and acquisitions and general corporate matters. From 1990 to 1993, Ms. Snyder served as general counsel to Nan Duskin, Inc. and its affiliated companies, which were in the businesses of women's retail fashion and real estate. From 1983 to 1989, Ms. Snyder was an associate at the law firm of Duane Morris LLP, where she practiced securities, banking and general corporate law.

Ronald K. Page—Mr. Page has served as Vice President, Corporate Development since joining the Company in July 2003. From January 1998 to May 2003, Mr. Page served in various positions with El Paso Field Services Company, including Vice President of Commercial Operations—Texas Pipelines and Processing, Vice President of Business Development and Director of Business Development. From October 1995 through December 1997, Mr. Page was employed as Vice President of Business Development by TPC Corporation (formerly Texas Power Corporation). For 17 years prior to 1995, Mr. Page served in various positions at Seagull Energy Corporation, including Vice President of Operations at Seagull's Enstar Natural Gas Company, Vice President of Pipelines and Marketing and Manager of Engineering.

Common Abbreviations and Definitions

The following terms have the meanings indicated below when used in this report.

Bbl—	a standard barrel of 42 U.S. gallons liquid volume
Bcf—	one billion cubic feet
Bcfe—	one billion cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
CBM—	coalbed methane
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 quantities to justify completion of the well
Exploratory or exploration well—	a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir
Gross acre or well—	an acre or well in which a working interest is owned
Mbbl—	one thousand barrels
Mbf—	one thousand board feet
Mcf—	one thousand cubic feet
Mcfe—	one thousand cubic feet equivalent
MMbbl—	one million barrels
MMbf—	one million board feet
MMbtu—	one million British thermal units
MMcf—	one million cubic feet
MMcfe—	one million cubic feet equivalent
Net acre or well—	gross acres or wells multiplied by the owned working interest in those gross acres or wells
NYMEX—	New York Mercantile Exchange
Present value of proved reserves—	the present value (discounted at 10%) of estimated future cash flows from proved oil and natural gas reserves, as estimated by our independent engineers, reduced by additional estimated future operating expenses, development expenditures and abandonment costs (net of salvage value) associated therewith (before income taxes)
Probable coal reserves—	those reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation

Productive wells—	wells that are producing oil or gas or that are capable of production
Proved developed reserves—	reserves that can be expected to be recovered through existing wells with existing equipment and operating methods
Proved reserves—	those estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years
Proved undeveloped reserves—	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
Proven coal reserves—	those reserves for which: (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well defined, that the size, shape, depth and mineral content of reserves are well-established
Standardized measure—	present value of proved reserves further reduced by the present value (discounted at 10%) of estimated future income taxes on cash flows using prices in effect at December 31, 2004, and estimated future costs as of December 31, 2004. Prices are held constant throughout the life of the properties except where Securities and Exchange Commission ("SEC") guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations.
Undeveloped acreage—	lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether such acreage contains estimated net 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

Item 2—*Properties*

Facilities

We are headquartered in Radnor, Pennsylvania, with additional offices in Kingsport, Tennessee, Houston, Texas, and Charleston, West Virginia. All of our office facilities are leased. We believe that our properties are adequate for our current needs.

Title to Properties

We believe that we have satisfactory title to all of our properties and the associated oil, gas and coal reserves in accordance with standards generally accepted in the oil and natural gas and coal royalty and land management industries.

As is customary in the oil and gas industry, we make only a cursory review of title to farmout acreage and to undeveloped oil and gas leases upon execution of any contracts. Prior to the commencement of drilling operations, a thorough title examination is conducted and curative work is performed with respect to significant defects. To the extent title opinions or other investigations reflect defects, we cure such title defects. If we were unable to remedy or 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. Prior to completing an acquisition of producing oil and gas assets, we obtain title opinions on all material leases. Our oil and gas properties are subject to customary royalty interests, liens for current taxes and other burdens that we believe do not materially interfere with the use or materially affect the value of such properties.

Of the 558 million tons of proven and probable coal reserves to which the Partnership had rights as of December 31, 2004, PVR owned the mineral interests and the majority of related surface rights to 519 million tons, or 93 percent, and leased the remaining 39 million tons, or seven percent, from unaffiliated third parties.

Information Regarding Oil and Gas Properties

Production and Pricing

The following table sets forth production, average sales prices and production costs with respect to our properties for the years ended December 31, 2004, 2003 and 2002.

	2004	2003	2002
Production			
Oil and condensate (Mbbls)*	396	625	349
Natural gas (MMcf)*	22,079	20,094	18,697
Total production (MMcfe)*	24,455	23,844	20,791
Average sales price			
Natural gas ($/Mcf)			
Actual price received for production	$ 6.44	$ 5.59	$ 3.39
Effect of derivative hedging activities	(0.17)	(0.28)	(0.04)
Average realized price	$ 6.27	$ 5.31	$ 3.35
Crude oil ($/Bbl)			
Actual price received for production	$ 39.09	$ 27.77	$ 24.39
Effect of derivative hedging activities	(5.34)	(0.86)	(0.76)
Average realized price	$ 33.75	$ 26.91	$ 23.63
Production cost ($/Mcfe)			
Lease operating expense	$ 0.57	$ 0.51	$ 0.45
Taxes other than income	0.38	0.40	0.27
General and administrative expense	0.34	0.33	0.40
Total production cost	$ 1.29	$ 1.24	$ 1.12

* Production for 2002 does not include approximately 16 Mbbls of oil condensate and 18 MMcf of natural gas production, or 114 MMcfe, related to discontinued operations.

Proved Reserves

The following table presents certain information regarding our proved reserves as of December 31, 2004, 2003 and 2002. The proved reserve estimates presented below were prepared by Wright and Company, Inc., independent petroleum engineers. For additional information regarding estimates of proved reserves, the preparation of such estimates by Wright and Company, Inc. and other information about our oil and gas reserves, see Note 25, "Supplemental Information on Oil and Gas Producing Activities (Unaudited)," in the Notes to Consolidated Financial Statements. Our estimates of proved reserves in the table above are consistent with those filed by us with other federal agencies.

	Oil and Condensate	Natural Gas	Natural Gas Equivalents	Pre-tax SEC PV10 Value	Year-end Prices Used	
	(MMbbls)	(Bcf)	(Bcfe)	($ millions)	$ / Bbl	$ /MMbtu
2004						
Developed	2.9	243	261	$632		
Undeveloped	3.4	73	93	163		
Total	6.3	316	354	$795	$43.46	$6.18
2003						
Developed	3.3	231	251	$570		
Undeveloped	3.3	52	72	126		
Total	6.6	283	323	$696	$32.52	$5.97
2002						
Developed	2.9	199	216	$404		
Undeveloped	2.5	42	57	77		
Total	5.4	241	273	$481	$31.13	$4.74

The standardized measure of discounted future net cash flows, which represents the present value of future net revenues after income taxes discounted at 10 percent, was $590 million, $512 million, and $355 million as of December 31, 2004, 2003 and 2002, respectively. For information on the changes in standardized measure of discounted future net cash flows, see Note 25, "Supplemental Information on Oil and Gas Producing Activities (Unaudited)," in the Notes to Consolidated Financial Statements.

In accordance with the SEC's guidelines, the engineers' estimates of future net revenues from our properties and the pre-tax SEC PV10 value thereof are made using oil and natural gas sales prices in effect as of December 31, 2004, and estimated future costs as of December 31, 2004. The prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. Prices for oil and gas are subject to substantial seasonal fluctuations as well as fluctuations resulting from numerous other factors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Proved reserves are the estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective 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 and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. Therefore, neither the pre-tax nor after-tax SEC PV10 value amounts shown above should be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. The information set forth in the foregoing tables includes revisions of certain volumetric reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in production prices.

Acreage

The following table sets forth our developed and undeveloped acreage at December 31, 2004. The acreage is located in the eastern and Gulf Coast onshore areas of the United States.

	Gross Acreage	Net Acreage
	(in thousands)	
Developed	642	503
Undeveloped	435	256
Total	1,077	759

Wells Drilled

The following table sets forth the gross and net number of exploratory and development wells drilled during the last three years. The number of wells drilled refers to the number of wells spud at any time during the respective year. Net wells equal the number of gross wells multiplied by our working interest in each of the gross wells. Productive wells represent either wells which were producing or which were capable of commercial production.

	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	134	89.7	161	117.0	87	58.4
Non-productive	1	0.3	1	1.0	3	2.5
Total development	135	90.0	162	118.0	90	60.9
Exploratory						
Productive	7	1.5	5	1.2	3	3.0
Non-productive	7	4.4	3	2.9	3	1.6
Under evaluation	3	2.6	10	10.0	—	—
Total exploratory	17	8.5	18	14.1	6	4.6
Total	152	98.5	180	132.1	96	65.5

The three exploratory wells under evaluation at the end of 2004 include a horizontal Devonian shale well in West Virginia, a coalbed methane ("CBM") well in Mississippi and a horizontal CBM well in Virginia. The Company expects to determine the commercial viability of these wells in the first half of 2005.

The 10 exploratory wells under evaluation at the end of 2003 are CBM wells drilled and completed in the Cherokee Basin in Chase and Greenwood Counties, Kansas. In 2004, the Company determined that these wells were not commercially viable, resulting in a $4.4 million write-off.

Productive Wells

The number of productive oil and gas wells in which we had a working interest at December 31, 2004, is set forth below. Productive wells are producing wells or wells capable of commercial production.

Operated Wells		Non-Operated Wells		Total	
Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
882	849.4	537	86.4	1,419	935.8

In addition to the above working interest wells, Penn Virginia owns royalty interests in 1,799 gross wells.

Information Regarding Coal Royalty and Land Management Properties

At December 31, 2004, the Partnership's coal reserves were located on 241,000 acres, including fee and leased acreage, in Virginia, West Virginia, New Mexico and eastern Kentucky. The coal reserves are in various surface and underground seams. As of December 31, 2004, the Partnership had approximately 558 million tons of proven and probable coal reserves, which are found in the following six separate properties:

- the Wise property, located in Wise and Lee Counties, Virginia and Letcher and Harlan Counties, Kentucky;
- the Coal River property, located in Boone, Fayette, Kanawha, Lincoln and Raleigh Counties, West Virginia;
- the New Mexico property, located in McKinley County, New Mexico;
- the northern Appalachia property, located in Barbour, Harrison, Lewis, Monongalia and Upshur Counties, West Virginia;
- the Spruce Laurel property, located in Boone and Logan Counties, West Virginia; and
- the Buchanan property, located in Buchanan County, Virginia.

Reserves are coal tons that can be economically extracted or produced at the time of determination considering legal, economic and technical limitations. Proven coal reserves are reserves for which (a) the quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling, and (b) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well-defined, that the size, shape, depth and mineral content of reserves are well-established. Probable coal reserves are reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are more widely spaced or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

In areas where geologic conditions indicate potential inconsistencies related to coal reserves, the Partnership performs additional exploration to ensure the continuity and mineablility of coal reserves. Consequently, sampling in those areas involves drill holes that are spaced closer together than those distances cited above.

Reserve estimates are adjusted annually for production, unmineable areas, acquisitions and sales of coal in place. The majority of PVR's reserves are high in energy content, low in sulfur and suitable for either the steam or metallurgical market.

The amount of coal a lessee can profitably mine at any given time is subject to several factors and may be substantially different from "proven and probable reserves." Included among the factors that influence profitability are the existing market price, coal quality and operating costs.

The following table sets forth production data and reserve information with respect to each of the Partnership's six properties:

Property	Production Year Ended December 31,			Proven and Probable Reserves at December 31, 2004		
	2004	2003	2002	Underground	Surface	Total
	(tons in millions)					
Wise	10.0	9.3	8.9	181.6	22.7	204.3
Coal River	7.8	3.9	2.5	121.6	72.6	194.2
New Mexico	5.5	6.3	0.2	—	67.8	67.8
Northern Appalachia	5.6	5.1	0.4	42.1	2.4	44.5
Spruce Laurel	1.9	1.5	1.8	30.3	15.7	46.0
Buchanan	0.4	0.4	0.5	1.2	0.1	1.3
Total	31.2	26.5	14.3	376.8	181.3	558.1

The following table sets forth the coal reserves the Partnership owns and leases with respect to each of its coal properties as of December 31, 2004:

Property	Owned	Leased	Total
	(tons in millions)		
Wise	204.3	—	204.3
Coal River	162.9	31.3	194.2
New Mexico	64.0	3.8	67.8
Northern Appalachia	44.5	—	44.5
Spruce Laurel	42.5	3.5	46.0
Buchanan	0.4	0.9	1.3
Total	518.6	39.5	558.1

The Partnership's coal reserve estimates were prepared from geological data assembled and analyzed by PVR's general partner's geologists and engineers. These estimates are compiled using geological data taken from thousands of drill holes, geophysical logs, adjacent mine workings, outcrop prospect openings and other sources. These estimates also take into account legal, qualitative, technical and economic limitations that may keep coal from being mined. Reserve estimates will change from time to time due to mining activities, analysis of new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods and other factors

The Partnership's timber assets consist of various hardwoods, primarily red oak, white oak, yellow poplar and black cherry. At December 31, 2004, the Partnership owned an estimated 167 MMbf of standing saw timber.

Item 3—*Legal Proceedings*

We are involved in various legal proceedings arising in the ordinary course of business. While the ultimate results of these cannot be predicted with certainty, management believes these claims will not have a material effect on our financial position, liquidity or operations.

Item 4—*Submission of Matters to a Vote of Security Holders*

There were no matters submitted to a vote of security holders during the fourth quarter of 2004.

PART II

Item 5—*Market for the Registrant's Common Equity and Related Stockholder Matters*

Common Stock Market Prices and Dividends

High and low sales prices and dividends for the last two years were:

Quarter Ended	Sales Price High	Sales Price Low	Cash Dividends Declared
December 31, 2004	$45.34	$35.23	$0.1125
September 30, 2004	$40.85	$33.02	$0.1125
June 30, 2004(1)	$37.07	$30.19	$0.1125
March 31, 2004(1)	$30.58	$26.39	$0.1125
December 31, 2003(1)	$28.88	$22.03	$0.1125
September 30, 2003(1)	$22.83	$19.83	$0.1125
June 30, 2003(1)	$22.53	$18.70	$0.1125
March 31, 2003(1)	$19.95	$17.05	$0.1125

(1) For comparative purposes, sales prices and dividends declared in the quarter ended June 30, 2004, and prior quarters have been adjusted for the effect of a two-for-one stock split on June 10, 2004. See Note 5, "Stock Split and Change in Par Value," in the Notes to Consolidated Financial Statements.

The Company's common stock is traded on the New York Stock Exchange under the symbol PVA.

Item 6—*Selected Financial Data*

Five Year Selected Financial Data

	Year Ended December 31, 2004	2003	2002	2001	2000
	(in thousands except share data)				
Revenues	$228,425	$181,284	$110,957	$ 96,571	$105,998
Operating income(a,b)	$ 80,796	$ 62,101	$ 30,791	$ 1,563	$ 65,684
Net income(c)	$ 33,355	$ 28,522	$ 12,104	$ 34,337	$ 39,265
Per common share:(d)					
Net income, basic	$ 1.82	$ 1.59	$ 0.68	$ 1.96	$ 2.38
Net income, diluted	$ 1.81	$ 1.58	$ 0.67	$ 1.93	$ 2.35
Dividends paid	$ 0.45	$ 0.45	$ 0.45	$ 0.45	$ 0.45
Total assets(e)	$783,335	$683,733	$586,292	$457,102	$268,766
Long-term debt	$188,926	$154,286	$106,887	$ 46,887	$ 47,500
Minority interest in PVR	$182,891	$190,508	$192,770	$144,039	$ —
Shareholders' equity	$252,860	$211,648	$187,956	$185,454	$171,162

(a) Certain reclassifications have been made to conform to the current year presentation.

(b) Operating income in 2004 included a $7.5 million loss on assets held for sale. Operating income in 2004, 2003, 2002 and 2001 included a $0.7 million, $0.4 million, $0.8 million and $33.6 million impairment of oil and gas properties, respectively. Operating income in 2000 included a $23.9 million gain on the sale of certain oil and gas properties.

(c) Net income in 2001 included a $54.7 million ($35.6 million after tax) gain on the sale of Norfolk Southern Corporation common stock.

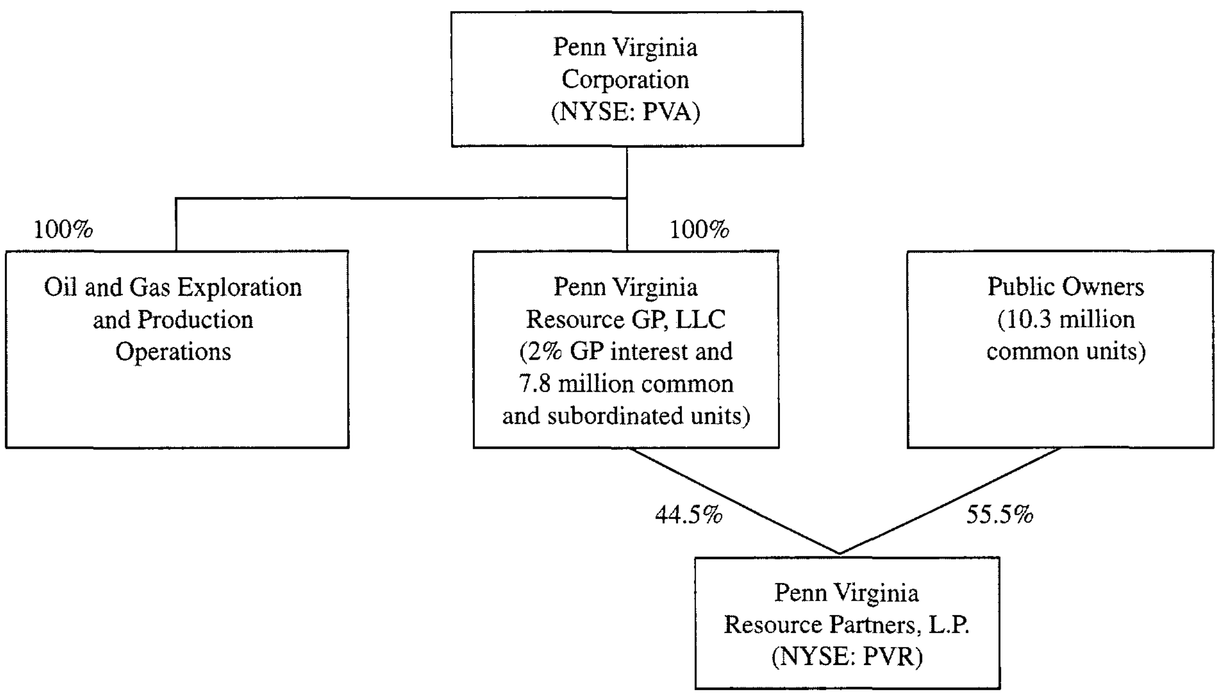
(d) For comparative purposes, amounts per common share in 2000 through 2003 have been adjusted for the effect of a two-for-one stock split on June 10, 2004. See Note 5, "Stock Split and Change in Par Value," in the Notes to Consolidated Financial Statements.
(e) Total assets reflected the acquisition of coal reserves from Peabody in December 2002 for $130.5 million. Total assets in 2001 included Gulf Coast oil and gas properties purchased in July 2001 for $157.1 million.

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

The following analysis of financial condition and results of operations of Penn Virginia Corporation and subsidiaries should be read in conjunction with the Consolidated Financial Statements and Notes thereto.

Overview

Penn Virginia Corporation ("Penn Virginia" or the "Company") is an independent energy company that is engaged in two primary business segments. Our oil and gas segment explores for, develops, produces and sells crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. Our coal royalty and land management segment operates through our 44.5 percent ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"). Penn Virginia and PVR are both publicly traded on the New York Stock Exchange under the symbols PVA and PVR, respectively. Due to our control of the general partner of PVR, the financial results of the Partnership are included in our consolidated financial statements. However, PVR functions with a capital structure that is independent of the Company, consisting of its own debt instruments and publicly traded common units. The following diagram depicts our ownership of PVR:



As a result of our ownership in the Partnership, we receive cash payments from PVR in the form of quarterly cash distributions. We received approximately $17.3 million of cash distributions from PVR during 2004. As part of our ownership of PVR's general partner, we also own the rights, referred to as incentive distribution rights, to receive an increasing percentage of quarterly distributions of available cash from operating surplus after certain levels of cash distributions have been achieved. As of December 31, 2004, PVR had achieved a level of distribution to allow us to receive an increased percentage of available cash. See Item 1, "Business—Coal Royalty and Land Management Operations," for more information on incentive distribution rights.

We are committed to increasing value to our shareholders by conducting a balanced program of investment in our two business segments. In the oil and gas segment, we expect to continue to execute a program combining relatively low risk, moderate return development drilling in Appalachia, Mississippi and east Texas and north Louisiana with higher risk, higher return exploration and development drilling in the onshore Gulf Coast, supplemented periodically with acquisitions. In addition to our conventional development program, we have continued to expand our presence in unconventional plays by developing CBM gas reserves in Appalachia. By employing horizontal drilling techniques, we expect to continue to increase the value from the CBM-prospective properties we own. We are committed to expanding our oil and gas reserves and production primarily by using our ability to generate exploratory prospects and development drilling programs internally.

We budgeted approximately $146 million for oil and gas capital expenditures in 2005. We do not budget major acquisitions of oil and gas properties. Borrowings against our credit facility were $76 million out of $150 million available as of December 31, 2004, and we expect to fund our 2005 budgeted capital expenditures with internal cash flow, supplemented by credit facility borrowings as needed.

In the coal royalty and land management segment, PVR continually evaluates acquisition opportunities that are accretive to cash available for distribution to PVR unitholders, of which we are the largest single unitholder. These opportunities include, but are not limited to, acquiring additional coal properties and reserves, acquiring or constructing assets for coal services, which would provide a fee-based revenue stream, and acquiring mid-stream natural gas assets.

During the first quarter of 2005, PVR made capital expenditures of approximately $191 million, plus usual closing adjustments, for the acquisition of a midstream natural gas business from Cantera Natural Gas LLC ("Cantera"). PVR funded this acquisition at closing with debt from a new, expanded credit facility, which PVR expects to reduce with proceeds from an anticipated secondary public offering of common units during the first quarter of 2005. PVR also anticipates 2005 capital expenditures of $0.3 million for coal services related projects and other property and equipment, which it believes can be funded with cash flow provided by operating activities.

2004 Performance—Oil and Gas Segment

Our oil and gas strategy has been to increase our presence in CBM and other unconventional natural gas to build a significant inventory of predictable, low risk development prospects, and to selectively drill exploration opportunities which could make a meaningful difference to the Company's production and reserve profile. During 2004, we believe progress was made in each area.

In 2004, we increased our oil and gas production to 24.5 Bcfe, a three percent increase over 23.8 Bcfe produced in 2003. This increase was the result of production from successful exploratory drilling projects in south Louisiana and the east Texas and north Louisiana Cotton Valley project, increased drilling in our Mississippi Selma Chalk fields and our Appalachia horizontal CBM project. This increase was offset primarily by production declines in several south Texas fields and a curtailment on two natural gas pipelines serving the Company's assets in southern West Virginia, which particularly affected the deliverability of the horizontal CBM program. The curtailments lasted from May through October and restricted 2004 production by approximately 1.1 Bcf. Average daily oil and gas production increased to 70.7 MMcfe in the fourth quarter of 2004 compared to 67.1 MMcfe in the fourth quarter of 2003.

We took steps to prevent future curtailments in order to accommodate the expected increases in gas volumes from our horizontal CBM program. We constructed a 15 mile, 12-inch pipeline and acquired long-term firm transportation on Columbia Gas Transmission's pipeline system effective in the fourth quarter of 2004.

Commodity prices, in particular for natural gas, were the largest single factor affecting our financial results in 2004. Price volatility in the natural gas market has been high in the last few years. Throughout 2002, 2003 and

2004, the NYMEX futures market traded at record price levels for natural gas. Our realized natural gas price in 2004 was $6.27 per Mcf, net of $0.17 per Mcf hedging loss. As part of our risk management strategy, we use financial instruments to hedge natural gas and, to a lesser extent, oil prices.

Our total oil and gas reserves at the end of 2004 were 354 Bcfe, an increase of 10 percent over 2003. Approximately 89 percent of our reserves at year-end 2004 were natural gas. Net of revisions, we added approximately 57 Bcfe of proved reserves primarily from extensions, discoveries and additions, replacing 233 percent of our 2004 production of 24.5 Bcfe. We drilled a total of 152 gross (98.5 net) wells during 2004, including 135 gross (90.0 net) development wells and 17 gross (8.5 net) exploratory wells. One development well (0.3 net) and seven gross (4.4 net) exploratory wells were not successful and 3 gross (2.6 net) exploratory wells were under evaluation at December 31, 2004.

During 2004, we continued to expand our CBM production and reserve base in central Appalachia through leasehold acquisitions and the use of a proprietary horizontal drilling technology. The technology is owned by our partner, and we have the right to use the technology under our agreement with our partner in a 16,000 square mile area of mutual interest ("AMI") covering virtually all of central Appalachia. We acquired over 75,000 acres during 2004 and now control over 360,000 acres of CBM-prospective leasehold within the AMI. By accelerating production from these normally long-lived reserves, this drilling technique has resulted in increased projected rates of return on the horizontal CBM wells drilled through 2004. This technique was used to drill and complete 20 gross (11.0 net) horizontal CBM wells during 2004, and our horizontal CBM production increased to 2.1 Bcfe in 2004 from 1.1 Bcfe in 2003. In 2005, our capital budget includes $21 million to drill 29 gross (15 net) horizontal CBM wells in Appalachia and $11 million for lease acquisitions and pipeline infrastructure. During 2004, a horizontal well was drilled in the Devonian shale and is currently under evaluation.

In 2003, we drilled 10 wells as part of a conventional CBM pilot project in the Cherokee Basin of southeastern Kansas, where we control over 40,000 acres. After performing production testing for a over a year, we evaluated the project to be non-commercial, resulting in a charge to exploration expense in the fourth quarter of 2004 of approximately $4.4 million.

Early in 2004, we entered into a joint venture with GMX Resources, Inc. [NASDAQ:GMXR] to drill development wells in the North Carthage Field in east Texas. The wells are drilled and completed in the Cotton Valley formation with the Travis Peak and Petit formations also present in some wells. Through the joint venture, we have drilling rights on approximately 13,500 acres. We estimate that 80 to 100 wells could ultimately be drilled on this acreage. Outside the joint venture area, we have acquired an additional 18,000 acres also prospective in the Cotton Valley formation.

In our Cotton Valley play in east Texas and north Louisiana, which includes the GMX joint venture, 23 gross (15.6 net) wells were drilled during 2004 with 100 percent success. Net Cotton Valley production for the year was 1.1 Bcfe, up from the 0.1 Bcfe produced in 2003 from operations preceding our GMX joint venture. We have continued to expand our leasehold position in the Cotton Valley play in east Texas, and we plan to begin drilling on the new acreage in the second half of 2005. The 2005 budget includes approximately $27 million to drill 24 gross (17 net) wells in east Texas and north Louisiana.

Another of our important development areas is the Selma Chalk formation in Mississippi. During 2004, 44 gross (43.6 net) Selma Chalk wells were drilled and all of the wells were successful. Production from this play was 4.9 Bcfe in 2004, up 29 percent from 3.8 Bcfe in 2003. Our 2005 budget includes approximately $23 million to drill 65 gross (64 net) wells in 2005.

During 2004, we used our Gulf Coast seismic data base, which now exceeds 8,000 square miles, to continue to increase our inventory of internally generated exploration prospects in both south Louisiana and south Texas. During 2004, we drilled 11 gross (3.0 net) exploratory wells in the Gulf Coast region. Of the 11 wells, six were successful, with three located in south Louisiana and three in south Texas. In St. Mary Parish of south Louisiana, we participated in the successful drilling of our first prospect identified with a 100 square mile proprietary 3D seismic program that was shot in 2003. The well, in which we have a 25 percent working interest, was drilled to a total depth of approximately 18,000 feet and found productive sands in two different intervals. Fourteen additional prospects have been identified within this 3D seismic survey, two of which are expected to be drilled in 2005. After drilling a successful exploratory well and a development well in the Creole area in Cameron Parish in 2003, an additional exploratory well was drilled in 2004 which was a dry hole, and another exploratory well was drilling at year end 2004. The Creole area, in which we have a 30 percent working interest, is expected to continue to be an active area for us in 2005, with three exploratory wells planned. Since commencing its south Louisiana exploratory drilling efforts in 2003, we have drilled eight successful exploratory wells in 10 attempts.

In south Texas, a successful Vicksburg exploratory well in which we have a 25 percent working interest was drilled in the Kingsville Field in Kleberg County. In the Esperanza project area in Nueces County, where we have a 33 percent working interest, two dry Vicksburg wells and one dry Frio well were drilled. The Vicksburg prospects were higher risk, high potential projects. We participated with a 20 percent working interest in a successful Frio exploratory well in Hidalgo County.

Our Board of Directors has approved a 2005 oil and gas capital expenditures budget of $146 million. We do not budget major acquisitions of oil and gas properties. Based on 2005 NYMEX prices of $6.00 per MMbtu for natural gas and $35.00 per barrel of oil, we expect to fund this capital budget using internally generated cash flows from oil and gas production, supplemented by borrowings under our credit facility as needed. Our credit facility consists of a $150 million commitment which, as of January 31, 2005, had outstanding borrowings of $76 million. Additionally, to provide greater certainty of having sufficient operating cash flows to fund our oil and gas capital expenditures program, we have an active commodity price hedging program. As of January 31, 2005, we had natural gas hedges in place for 2005 covering approximately 25,800 MMbtu per day. These positions, primarily in the form of costless collars, provide average floor and ceiling prices of $5.25 and $7.40 per MMbtu, respectively, and cover approximately one third of our expected 2005 natural gas production. We also have approximately 13,700 MMbtu per day of natural gas hedged for the first half of 2006 at average floor and ceiling prices of $5.20 and $9.60 respectively. Oil production comprises an insignificant part of our expected production, and no oil production was hedged as of January 31, 2005.

2004 Performance—Coal Royalty and Land Management Segment (PVR)

PVR's coal royalty revenues increased 38 percent from $50.3 million in 2003 to $69.6 million in 2004. This increase was a result of an increase in coal production of 4.7 million tons, or 18 percent, combined with a 17 percent increase in average gross royalties per ton from $1.90 in 2003 to $2.23 in 2004. This production increase was primarily related to a longwall mining operation started by one of PVR's lessees in the first quarter of 2004 on PVR's Coal River property. This longwall operation increased production by 2.6 million tons and added $5.6 million in revenues in 2004. The addition of a mine operator and a new mine by another Coal River lessee contributed approximately 0.7 million tons of coal production, or $3.1 million of revenue. Increased demand also fueled a coal sales price increase in the region, which in turn resulted in a seven percent increase in average gross royalty per ton on the Coal River property, from $2.42 per ton in 2003 to $2.60 per ton in 2004. Revenues at the Wise property increased by $5.9 million primarily as a result of a 19 percent increase in the average royalty rate from $2.29 per ton in 2003 to $2.72 per ton in 2004. Revenues from the Spruce Laurel property increased by $1.9 million, primarily as the result of a 23 percent increase in the average gross royalty per ton on the Spruce Laurel property, from $2.07 per ton in 2003 to $2.54 per ton in 2004.

As part of PVR's coal land management business, PVR owns approximately 167 million board feet of standing timber. PVR generally sells cutting rights to various contractors who cut in advance of a mining project. Timber revenues in 2004 were $0.7 million, down from $1.0 million in 2003.

Coal prices, especially in central Appalachia where the majority of PVR's production is located, have increased significantly since the beginning of 2003. The price increase stems from several causes including increased electricity demand and decreasing coal production in central Appalachia.

PVR also collects fees and railroad rebates related to its ownership of the coal preparation plant and coal loading facility on the West Coal River property. This new facility and several smaller modular coal preparation plants resulted in additional coal services revenues, supplementing revenues from the Shober loading facility, opened in 2002, in Virginia. PVR also spent approximately $4.4 million to construct a third large-scale coal loading facility on its Coal River property, and the facility began operating in February 2004. Coal services revenues increased to $3.4 million in 2004 from $2.1 million in 2003, and are expected to increase to over $4.1 million in 2005. PVR believes that these types of fee-based infrastructure assets provide good investment and cash flow opportunities for the Partnership, and it continues to look for additional investments of this type as well as other primarily fee-based assets, including oil and gas midstream assets.

The Partnership was able to take advantage of another growth opportunity in 2004 by acquiring from affiliates of Massey Energy Company for $28.4 million a 50 percent interest in a joint venture formed to own and operate end-user coal handling facilities. This joint venture is pursuing additional projects to build and operate coal handing facilities for industrial customers.

In March 2005, PVR purchased a natural gas gathering and processing business from Cantera for $191 million cash. These midstream assets include approximately 3,400 miles of gas gathering pipelines that supply three natural gas processing facilities which have 160 million cubic feet per day (MMcfd) of total capacity. The assets derive revenue primarily from the sharing of proceeds on the sale of natural gas and natural gas liquids under contracts with natural gas producers and from fees charged for gathering and processing of natural gas and other related services. The assets are located in four geographic regions: the Oklahoma and Texas Panhandles, north central Oklahoma, north central Texas and the Arkoma basin.

Critical Accounting Policies and Estimates

The process of preparing financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") requires the management of the Company 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 policies which involve the judgment of our management.

Reserves

The estimates of oil and gas reserves are the single most critical estimate included in our financial statements. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities including projecting the total quantities in place, future production rates and the 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.

Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those quantities that require additional capital investment through drilling or well recompletion techniques.

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 several factors which could change our estimates of oil and gas reserves. Significantly higher or lower product prices could lead to changes in the amount of reserves due to economic limits. 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. Additionally, we perform impairment tests pursuant to Statement of Financial Accounting Standards ("SFAS") No. 144 when significant events occur, such as a market move to a lower price environment or a material revision to our reserve estimates. We have recognized non-cash pretax charges of $0.7 million, $0.4 million and $0.8 million for 2004, 2003 and 2002, respectively, related to the impairment of oil and gas properties.

Depreciation and depletion of oil and gas producing properties is determined by the unit-of-production method and could change with revisions to estimated proved recoverable reserves.

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. Annual lease rentals, exploration costs, geological, geophysical and seismic costs and exploratory dry-hole costs are expensed as incurred. Pursuant to Statement of Financial Accounting Standards ("SFAS") No. 19, "Financial Accounting and Reporting by Oil and Gas Reporting Companies," costs of drilling exploratory wells are initially capitalized and later charged to expense if upon determination the wells do not justify commercial development. Occasionally, an exploratory well may be determined to have found oil and gas reserves, but classification of those reserves as proved cannot be made when drilling is completed. If classification of proved reserves cannot be made in an area requiring a major capital expenditure, the cost of drilling the exploratory well is carried as an asset provided that (a) there have been sufficient reserves found to justify completion as a producing well if the required capital expenditure is made and (b) further well completion work needs to be performed or additional exploratory wells need to be drilled and those activities are either underway or firmly planned for the near future. If either of these two criteria is not met, exploratory well costs are expensed. For all other exploratory wells, costs of exploratory wells are expensed if the reserves cannot be classified as proved after one year following the completion of drilling.

A portion of the carrying value of the Company's oil and gas properties is attributable to unproved properties. At December 31, 2004, the costs attributable to unproved properties were approximately $61 million. These costs are not currently being depreciated or depleted. As exploration work progresses and the reserves on these properties are proven, capitalized costs of the properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be expensed. The timing of any writedowns of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Asset Retirement Obligations

In accordance with SFAS No. 143, we make estimates of the timing and future costs of plugging and abandoning wells. Estimated abandonment dates will be revised in the future based on changes to related economic lives, which vary with product prices and production costs. Estimated plugging costs may also be adjusted to reflect changing industry experience. Increases in operating costs and decreases in product prices would increase the estimated amount of our plugging and abandonment obligations and increase depletion expense. Our cash flows would not be affected until costs to plug and abandon were actually incurred.

Oil and Gas Revenues

Oil and gas sales revenues are recognized when crude oil and natural gas volumes are produced and sold for our account. 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, accruals for revenues and accounts receivable are made based on estimates of our share of production, particularly from properties that are operated by our partners. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results will include estimates of production and revenues for the related time period. Any differences between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Hedging Activities

We enter into derivative financial instruments that qualify for hedge accounting under SFAS No. 133. Hedge accounting affects the timing of revenue recognition in our statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred as to statement of income recognition. The position reflected in the statement of income is based on the actual settlements with the counterparty. We include this gain or loss in oil and gas revenues. If our natural gas and crude oil derivatives did not qualify for hedge accounting or we chose not to use this hedge accounting methodology, we could experience significant changes in the estimate of non-cash derivative gain or loss recognized in revenue due to swings in the value of these contracts. These fluctuations could be especially significant in a volatile pricing environment.

Coal Royalties

Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenues from those sales. Since PVR does not operate any mines, it does not have access to actual production and revenue information until approximately 30 days following the month of production. Therefore, the financial results of the Partnership include estimated revenues and accounts receivable for this 30-day period. Any differences between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Acquisitions

Oil and Gas

On January 22, 2003, we acquired a 25 percent non-operating working interest in properties located in a producing field in south Texas ("the south Texas acquisition"). The properties were acquired in a cash transaction with a private investor group for $33.5 million. The acquisition, which was effective December 31, 2002, was financed with the Company's existing credit facility. Nine producing wells were acquired at the time of the acquisition. Ten successful development wells and one development dry hole have been drilled in the field since the acquisition date.

Coal Royalty and Land Management

Midstream Oil and Gas. In March 2005, PVR purchased from Cantera a natural gas gathering and processing business with assets in Oklahoma and Texas for $191 million of cash (the "Cantera Acquisition"). As a result of this acquisition, PVR now owns and operates a business, under the name PVR Midstream LLC, consisting of a set of midstream assets that include approximately 3,400 miles of gas gathering pipelines that supply three natural gas processing facilities with 160 MMcfd of total capacity. PVR will derive revenues from this business primarily from the sharing of sales proceeds of natural gas and natural gas liquids under contracts with natural gas producers and from fees charged for the gathering and processing of natural gas and other related services. These midstream assets are located in four geographic regions: the Oklahoma and Texas Panhandles, north central Oklahoma, north central Texas and the Arkoma basin. Concurrent with the closing of the Cantera Acquisition, the Partnership completed an expanded five-year credit facility led by PNC Capital Markets and RBC Capital Markets, consisting of a $150 million revolving credit facility and a $110 million term loan. PVR used the term loan and a portion of the revolving credit facility to fund the Cantera Acquisition. The new revolving credit facility was also used to pay off PVR's existing Revolver which had an outstanding balance of $30.0 million at December 31, 2004. The Partnership anticipates using a combination of its credit facility and new equity capital to permanently finance this acquisition. As of December 31, 2004, the Partnership capitalized $0.7 million for costs related to the Cantera Acquisition.

In order to protect the projected cash flows of the acquisition from the risk of commodity price volatility, in January 2005, PVR entered into notional derivative contracts for approximately 75 percent of the net volume of natural gas liquids expected to be sold from April 2005 through December 2006. The underlying commodity prices that PVR expects to realize in future periods, after giving effect to the derivative contracts, are expected to exceed the commodity prices used in financial evaluation of the acquisition.

Since the time PVR entered into the derivative contracts, futures prices of natural gas liquids have increased significantly. As of March 2, 2005, the aggregate fair value of these derivative contracts was unfavorable to PVR. Upon closing of the Cantera Acquisition and documenting hedge effectiveness, these derivative contracts are expected to qualify as cash flow hedges in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," ("SFAS No. 133"). (See our previous discussion of hedging activities in "Critical Accounting Policies and Estimates.") From the time the derivative contracts were executed until completion of the hedge effectiveness documentation, the derivative contracts do not qualify for hedge accounting. The unfavorable change in the derivative contracts' fair value was estimated to be approximately $8.9 million as of March 2, 2005. The fair value at the date the derivative contracts qualify for hedge accounting will be recognized as a non-cash reduction of earnings for PVR in the first quarter of 2005. The $8.9 million as of March 2, 2005, is the most recently available fair value estimate and is subject to change until the derivative contracts qualify for hedge accounting. All cash settlements of these derivative contracts will be paid or received over the 21-month term of the contracts.

Coal Handling Joint Venture. In July 2004, the Partnership acquired from affiliates of Massey Energy Company a 50 percent interest in a joint venture formed to own and operate end-user coal handling facilities. The purchase price was $28.4 million and was funded through the Partnership's credit facility. The joint venture owns coal handling facilities which unload shipments and store and transfer coal for three industrial coal consumers in the chemical, paper and lime production industries located in Tennessee, Virginia and Kentucky, respectively. A combination of fixed monthly fees and per ton throughput fees is paid by those consumers under long-term leases expiring between 2007 and 2019. PVR recognized equity earnings of $0.4 million related to its ownership in the joint venture in 2004. The Partnership received a joint venture distribution of approximately $1.0 million during the fourth quarter of 2004 relating to third quarter operations.

Coal Loadout Facility. In January 2004, the Partnership completed the construction of a new coal loadout facility for one of its lessees on its Coal River property in West Virginia. The $4.4 million loadout facility is designed for the high-speed loading of 150-car unit trains and became operational on February 1, 2004. This facility generated additional revenues of approximately $0.5 million in 2004, and the Partnership believes it resulted in increased coal production of approximately 0.4 million tons from this lessee during 2004.

Coal Reserves. In December 2002, the Partnership acquired (the "Peabody Acquisition") 120 million tons of proven and probable coal reserves (the "Reserves") located in New Mexico (80 million tons) and West Virginia (40 million tons) from Peabody Energy Corporation ("Peabody"). All of the Reserves were leased back to subsidiaries of Peabody by the Partnership. The Peabody Acquisition provided geographic diversity by exposing PVR to new markets in the western United States and in northern Appalachia. The inclusion of Peabody as a significant part of PVR's lessee mix added strength and stability to its lessee group. The acquisition was funded with $72.5 million of cash, 1.53 million of the Partnership's common units and 1.23 million of the Partnership's Class B common units. All of the Class B common units were converted into common units in accordance with their terms, upon the approval of PVR common unitholders in July 2003. In December 2003 and January 2004, Peabody sold 1.15 million of its common units in public offerings sponsored by the Partnership, and, as of December 31, 2004, Peabody held 0.84 million of PVR's common units.

In August 2002, the Partnership purchased approximately 16 million tons of proven and probable coal reserves located on the Upshur properties in northern Appalachia for $12.3 million (the "Upshur Acquisition"). The properties, which include approximately 18,000 mineral acres, contain predominantly high sulfur, high BTU coal reserves.

Results of Operations

Selected Financial Data—Consolidated

	2004	2003	2002
	(in millions, except share data)		
Revenues	$228.4	$181.3	$111.0
Operating costs and expenses	$147.6	$119.2	$ 80.2
Operating income	$ 80.8	$ 62.1	$ 30.8
Net income	$ 33.4	$ 28.5	$ 12.1
Earnings per share, basic	$ 1.82	$ 1.59	$ 0.68
Earnings per share, diluted	$ 1.81	$ 1.58	$ 0.67
Cash flows provided by operating activities	$146.4	$109.7	$ 65.8

Included in net income for 2003 was $1.4 million, or $0.08 per diluted share, related to the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations." This amount is included in the oil and gas segment's contribution to net income.

Consolidated Net Income

Net income for the Company totaled $33.4 million in 2004, an increase of 17 percent over 2003. The higher earnings were primarily the result of both increased natural gas and coal production and higher prices for natural gas, crude oil and coal.

Oil and Gas Segment

In our oil and gas segment, we explore for, develop and produce crude oil and natural gas in the eastern and Gulf Coast onshore regions of the United States. Our revenues, profitability and future rate of growth are highly dependent on the prevailing prices for oil and natural gas, which are affected by numerous factors that are generally beyond the Company's control. Crude oil prices are generally determined by global supply and demand. Natural gas prices are influenced by national and regional supply and demand. A substantial or extended decline in the prices of oil or natural gas could have a material adverse effect on our revenues, profitability and cash flow and could, under certain circumstances, result in an impairment of our oil and natural gas properties. Our future profitability and growth is also highly dependent on the results of our exploratory and development drilling programs.

Selected Financial and Operating Data—Oil and Gas

Year Ended December 31, 2004, Compared to Year Ended December 31, 2003

	2004	2003	% Change	2004	2003	% Change
	(in thousands, except as noted)			(per MMcfe)*		
Production						
Natural gas (MMcf)	22,079	20,094	10%			
Oil and condensate (Mbbls)	396	625	(37)%			
Total production (MMcfe)	24,455	23,844	3%			
Revenues						
Natural gas						
Revenue received for production	$142,192	$112,193	27%	$ 6.44	$ 5.59	15%
Effect of hedging activities	(3,770)	(5,578)	(32)%	(0.17)	(0.28)	(39)%
Net revenue realized	138,422	106,615	30%	6.27	5.31	18%
Oil and condensate						
Revenue received for production	15,480	17,355	(11)%	39.09	27.77	41%
Effect of hedging activities	(2,116)	(539)	293%	(5.34)	(0.86)	521%
Net revenue realized	13,364	16,816	(21)%	33.75	26.91	25%
Other income	(114)	1,391				
Total revenues	151,672	124,822	22%	6.20	5.23	19%
Expenses						
Lease operating	13,949	12,115	15%	0.57	0.51	12%
Taxes other than income	9,325	9,515	(2)%	0.38	0.40	(5)%
General and administrative	8,336	7,804	7%	0.34	0.33	3%
Production costs	31,610	29,434	7%	1.29	1.24	4%
Exploration	26,058	15,503	68%	1.07	0.65	65%
Depreciation, depletion and amortization	35,886	33,164	8%	1.47	1.39	6%
Loss on assets held for sale	7,541	—	—	0.31	—	—
Impairment of properties	655	406	61%	0.03	0.02	50%
Total expenses	101,750	78,507	30%	4.17	3.30	26%
Income before income taxes	$ 49,922	$ 46,315	8%	$ 2.03	$ 1.93	6%

* Natural gas revenues are shown per Mcf, oil and condensate revenues are shown per Bbl, and all other amounts are shown per Mcfe.

Production. The increase in production was primarily due to production from successful exploratory drilling projects in south Louisiana, the Cotton Valley play in east Texas and north Louisiana, increased drilling in our Selma Chalk fields in Mississippi and our horizontal CBM drilling project in Appalachia, offset primarily by production declines in several south Texas fields and a pipeline curtailment in Appalachia.

Revenues. Increased realized prices for natural gas and crude oil accounted for approximately $24.0 million, or 89 percent, of the increase in total oil and gas revenues from 2003 to 2004. Approximately 90 percent of our 2004 production was natural gas, for which the average realized price received was $6.27 per Mcf compared with $5.31 per Mcf in 2003, an 18 percent increase. The average realized oil price received was $33.75 per barrel for 2004, up 25 percent from $26.91 per barrel in 2003.

Due to the volatility of crude oil and natural gas prices, we hedge the price received for certain sales volumes through the use of swaps and costless collars in accordance with our hedging policy. Gains and losses from hedging activities are included in revenues when the hedged production occurs. In 2004, approximately 36 percent of our natural gas was hedged, primarily using costless collars, at an average floor price of $3.93 per MMbtu and ceiling price of $5.99 per MMbtu. We also hedged approximately 45 percent of our crude oil production using fixed price swaps with an average price of $29.78 per barrel. We recognized a loss on settled hedging activities of $5.9 million in 2004, compared with a loss of $6.1 million in 2003.

Operating expenses. The oil and gas segment's aggregate operating costs and expenses in 2004 increased primarily due to higher exploration expenses, higher depreciation, depletion and amortization ("DD&A") and a loss on assets held for sale.

Exploration expenses for the years ended December 31, 2004 and 2003, consisted of the following (in thousands):

	2004	2003
Dry hole costs	$10,284	$ 5,186
Seismic	9,225	8,713
Unproved leasehold write-offs	5,726	802
Other	823	802
Total	$26,058	$15,503

Exploration expenses increased primarily due to increased unproved leasehold write-offs related to expiring lease options in south Texas, unproved leasehold write-offs and dry hole costs related to our CBM pilot drilling program in Kansas and higher dry hole costs resulting from drilling seven unsuccessful exploratory wells in 2004 compared to three unsuccessful exploratory attempts in 2003.

As a percentage of revenues, taxes other than income decreased from 7.6 percent in 2003 to 6.1 percent in 2004. The decrease is primarily due to a severance tax refund received in the fourth quarter of 2004 related to the south Texas properties acquired in 2003.

Oil and gas DD&A increased primarily due to higher production as discussed previously, and the weighted average DD&A rate increased from $1.39 per Mcfe in 2003 to $1.49 per Mcfe in 2004. The increase in the weighted average DD&A rate was the result of a greater percentage of production coming from relatively higher cost horizontal CBM and Gulf Coast wells and the new pipeline infrastructure placed in service during the fourth quarter of 2004.

A loss of $7.5 million loss on assets held for sale resulted from the write-down to realizable value of a group of non-core properties in west Texas which were sold in January 2005.

Year Ended December 31, 2003, Compared to Year Ended December 31, 2002

	2003	2002	% Change	2003	2002	% Change
	(in thousands, except as noted)			(per MMcfe)*		
Production						
Natural gas (MMcf)**	20,094	18,697	7%			
Oil and condensate (Mbbls)**	625	349	79%			
Total production (MMcfe)**	23,844	20,791	15%			
Revenues						
Natural gas						
Revenue received for production	$112,193	$63,288	77%	$ 5.59	$ 3.39	65%
Effect of hedging activities	(5,578)	(736)	658%	(0.28)	(0.04)	600%
Net revenue realized	106,615	62,552	70%	5.31	3.35	59%
Oil and condensate						
Revenue received for production	17,355	8,512	104%	27.77	24.39	14%
Effect of hedging activities	(539)	(266)	103%	(0.86)	(0.76)	13%
Net revenue realized	16,816	8,246	104%	26.91	23.63	14%
Other income	1,391	714	95%			
Total revenues	124,822	71,512	75%	5.23	3.44	52%
Expenses						
Lease operating	12,115	9,253	31%	0.51	0.45	13%
Taxes other than income	9,515	5,618	69%	0.40	0.27	48%
General and administrative	7,804	8,381	(7)%	0.33	0.40	(18)%
Production costs	29,434	23,252	27%	1.24	1.12	11%
Exploration	15,503	7,549	105%	0.65	0.36	81%
Depreciation, depletion and amortization	33,164	26,336	26%	1.39	1.27	9%
Impairment of properties	406	796	(49)%	0.02	0.04	(50)%
Total expenses	78,507	57,933	36%	3.30	2.79	18%
Income before income taxes	$ 46,315	$13,579	241%	$ 1.93	$ 0.65	197%

* Natural gas revenues are shown per Mcf, oil and condensate revenues are shown per Bbl, and all other amounts are shown per Mcfe.

** Production for 2002 does not include 16 Mbbls of oil and condensate and 18 MMcf of natural gas production, or 114 MMcfe, related to discontinued operations.

Production. Oil and natural gas production increased primarily due to the south Texas acquisition in January 2003 and the drilling programs in 2003 and 2002. Increased oil and natural gas production accounted for approximately $11.2 million, or 21 percent, of the increase in total oil and gas revenues from 2002 to 2003.

Revenues. Increased crude oil and natural gas realized prices accounted for approximately $41.4 million, or 78 percent, of the increase in total oil and gas revenues from 2002 to 2003. Approximately 84 percent of our 2003 production was natural gas, for which the average natural gas price received during 2003 was $5.31 per Mcf compared with $3.35 per Mcf in 2002, a 59 percent increase. The average oil price received was $26.91 per barrel for 2003, up 14 percent from $23.63 per barrel in 2002.

Due to the volatility of crude oil and natural gas prices, we hedge the price received for sales volumes through the use of swaps and costless collars in accordance with our hedging policy. Gains and losses from hedging activities are included in revenues when the hedged production occurs. In 2003, approximately

45 percent of our natural gas was hedged, primarily using costless collars, at an average floor price of $3.83 per MMbtu and ceiling price of $5.67 per MMbtu. We also hedged approximately 26 percent of our crude oil production using fixed price swaps with an average price of $26.74 per barrel. We recognized a loss on settled hedging activities of $6.1 million in 2003, compared with a loss of $1.0 million in 2002.

Operating expenses. The oil and gas segment's aggregate operating costs and expenses in 2003 increased primarily due to increased lease operating expenses, exploration expenses, taxes other than income and DD&A.

The increase in lease operating expenses related to operations associated with the south Texas acquisition in January 2003 and new producing wells resulting from successful drilling activities in 2003. In addition to new operations, there were increased well workover costs associated with various fields.

Exploration expenses for the years ended December 31, 2003 and 2002, consisted of the following (in thousands):

	2003	2002
Seismic	$ 8,713	$4,892
Dry hole costs	5,186	1,357
Unproved leasehold write-offs	802	899
Other	802	401
Total	$15,503	$7,549

Exploration expenses increased primarily due to unsuccessful exploratory wells and the additional purchase of seismic data to evaluate both existing and new prospects during 2003 compared to 2002. There were three unsuccessful exploratory attempts in both years; however, the location, type and depth of the wells drilled changed between years. The unsuccessful wells in 2003 were primarily in the Gulf Coast region, while the unsuccessful wells in 2002 were in the Appalachia region, which has smaller, less costly drilling projects than the Gulf Coast region.

Taxes other than income taxes increased as a result of the increased revenues due to the higher prices received for natural gas and crude oil as well as increased production in 2003 as compared to 2002.

Oil and gas DD&A expense increased primarily due to higher production, as discussed earlier, and an increase in the weighted average DD&A rate from $1.27 per Mcfe in 2002 to $1.39 per Mcfe in 2003. The increase in the weighted average DD&A rate was the result of a greater percentage of production coming from fields which carry higher reserve replacement cost averages.

Coal Royalty and Land Management Segment (PVR)

The coal royalty and land management segment includes PVR's coal reserves, its timber assets and its other land assets. The assets, liabilities and earnings of PVR are fully consolidated in our financial statements, with the public unitholders' interest reflected as a minority interest.

The Partnership enters into leases with various third-party operators for the right to mine coal reserves on the Partnership's properties in exchange for royalty payments. The Partnership does not operate any mines. Approximately 79 percent of the Partnership's 2004 coal royalty revenues and 72 percent of its 2003 coal royalty revenues were derived from coal mined on the Partnership's properties and sold by its lessees under leases providing for royalty rates per ton leased on the higher of a percentage of the gross sales price or a fixed price per ton of coal, with pre-established minimum monthly or annual rental payments. The balance of the Partnership's 2004 and 2003 coal royalty revenues was derived from coal mined on two of the Partnership's properties under leases containing fixed royalty rates per ton of coal mined and sold ("fixed rate leases"). The royalty rates under those leases escalate annually, with pre-established minimum monthly payments. In addition to coal royalty revenues, the Partnership generates coal services revenues from fees charged to lessees for the use of coal preparation and transloading facilities. The Partnership also generates revenues from the sale of standing timber on its properties.

Coal royalties are impacted by several factors that PVR generally cannot control. The number of tons mined annually is determined by an operator's mining efficiency, labor availability, geologic conditions, access to capital, ability to market coal and ability to arrange reliable transportation to the end-user. The possibility exists that new legislation or regulations may be adopted which may have a significant impact on the mining operations of the Partnership's lessees or their customers' ability to use coal and may require PVR, its lessees or its lessee's customers to change operations significantly or incur substantial costs.

Selected Financial and Operating Data—Coal Royalty and Land Management

Year Ended December 31, 2004, Compared to Year Ended December 31, 2003

	2004	2003	% Change
	(in thousands, except as noted)		
Revenues			
Coal royalties	$ 69,643	$ 50,312	38%
Coal services	3,391	2,111	61%
Timber	702	1,020	(31)%
Other	1,894	2,199	(14)%
Total revenues	75,630	55,642	36%
Expenses			
Operating	7,224	4,235	71%
Taxes other than income	948	1,256	(25)%
General and administrative	8,307	7,013	18%
Operating expenses before non-cash charges	16,479	12,504	32%
Depreciation, depletion and amortization	18,632	16,578	12%
Total expenses	35,111	29,082	21%
Operating income	40,519	26,560	53%
Interest expense	(7,267)	(4,986)	46%
Interest income and other	1,063	1,223	(13)%
Income from operations before minority interest, income taxes and cumulative effect of change in accounting principle	34,315	22,797	51%
Minority interest	(19,023)	(12,510)	52%
Contribution to income from operations before income taxes and cumulative effect of change in accounting principle	$ 15,292	$ 10,287	49%
Production			
Royalty coal tons produced by lessees (thousands)	31,181	26,463	18%
Timber sales (Mbf)	2,567	5,250	(51)%
Prices			
Royalty per ton	$ 2.23	$ 1.90	17%
Timber sales price per Mbf	$ 249	$ 179	39%

Revenues. The increase in coal royalty and land management segment revenues is primarily related to increased royalties received from PVR's lessees.

Coal royalty revenues increased due to increased production by PVR's lessees and higher royalty rates. The Partnership's lessees mined approximately 31.2 million tons of coal in 2004 from PVR's properties and paid an average royalty of $2.23 per ton, compared with approximately 26.5 million tons mined in 2003 at an average royalty of $1.90 per ton. In 2004, approximately 20.9 million tons of coal were mined on properties with market-sensitive leases, with an average royalty rate of $2.64 per ton, compared with 15.9 million tons of coal and an average royalty rate of $2.28 per ton in 2003. Coal mined from fixed rate leases during 2004 totaled 10.3 million tons at an average royalty rate of $1.41 per ton, compared with 10.6 million tons and an average royalty rate of $1.33 per ton in 2003. Average gross royalties per ton increased by 18 percent due primarily to stronger market conditions for coal and the resulting higher coal prices. Production increased by 17 percent primarily due to the following factors:

- Production on the Coal River property increased by 3.9 million tons, which resulted in an increase in revenues of $10.8 million. One lessee, which utilizes longwall mining, began mining on one of PVR's subleased properties from an adjacent property during the first quarter of 2004, which resulted in an additional 2.6 million tons of coal production, or $5.6 million in revenues in 2004. The addition of a mine operator and a new mine by another lessee contributed approximately 0.7 million tons of coal production, or $3.1 million of revenue. The commencement of operations in July 2003 on the West Coal River property also contributed an additional 0.5 million tons, or $1.5 million of revenue. Increased demand also fueled a coal sales price increase in the region, which in turn resulted in a seven percent increase in the average gross royalty per ton on the Coal River property, from $2.42 per ton in 2003 to $2.60 per ton in 2004.
- Production on the Wise property increased by 0.7 million tons and revenues increased by $5.9 million, of which approximately $4.0 million related to an increase in the average royalty rate received from PVR's lessees. Increased coal prices fueled by stronger demand in the region resulted in higher price realizations by PVR's lessees. This caused a 19 percent increase in the average gross royalty per ton from $2.29 per ton in 2003 to $2.72 per ton in 2004. Production increased primarily due to four new mines, including one operated by a new lessee, and certain lessees' ability to increase operating days in response to higher coal demand.
- Production on the Spruce Laurel property increased by 0.5 million tons, and revenues increased by $1.9 million. The revenue increase was primarily the result of increased coal sales prices fueled by stronger demand in the region. The higher royalty rates received from PVR's lessees resulted in a 23 percent increase in the average gross royalty per ton on the Spruce Laurel property, from $2.07 per ton in 2003 to $2.54 per ton in 2004.

Coal services revenues increased primarily as a result of start-up operations at PVR's West Coal River and Bull Creek facilities in July 2003 and February 2004, respectively.

Timber revenues decreased due to the timing of a parcel sale of PVR's standing timber in 2003 and poor weather conditions in the second quarter of 2004.

Other revenues decreased due to a reduction in minimum rental revenues, partially offset by equity earnings and a gain on the sale of property. Minimum rental revenues decreased from $1.7 million in 2003 to $0.8 million in 2004 primarily due to the expiration of amounts available for recoupment by PVR's lessees. The amount recognized in 2003 primarily related to four leases. Each of these leases was assigned to a new lessee approved by PVR. The leases were amended at the time of assignment to allow the new lessees additional time to offset actual production against minimum rental payments. The Partnership recognized equity earnings of $0.4 million in 2004, representing PVR's portion of earnings from its investment in the coal handling joint venture with Massey Energy since PVR acquired the equity investment in July 2004. A $0.3 million gain on the 2004 sale of surface property in Virginia was recognized in 2004 other revenues.

Operating costs and expenses. The increase in aggregate operating costs and expenses primarily relates to an increase in operating expenses, general and administrative expenses and DD&A, partially offset by a decrease in taxes other than income. Operating expenses include royalty expenses paid on leased coal properties and other operating expenses. Royalty expenses increased by 54 percent to $6.1 million in 2004 from $2.7 million in 2003 due to an increase in production by lessees on PVR's subleased properties, primarily the Coal River property. Production from subleased properties doubled to 7.8 million tons in 2004 from 3.9 million tons in 2003. Other operating expenses increased due to the assumption by a new lessee of costs incurred after May 2003 to maintain idled mines on the West Coal River property, which is part of the Coal River property. PVR paid these costs through May 2003.

The decrease in taxes other than income was attributable to property taxes in 2003 resulting from the assumption by a new lessee of the property tax obligation on PVR's West Coal River property for which we had been responsible since the bankruptcy of our initial West Coal River lessee.

General and administrative expenses increased by $1.3 million. Approximately $0.2 million was attributable to costs related to a secondary public offering for the sale of common units held by an affiliate of Peabody. The remainder is primarily attributable to increased professional fees and payroll costs relating to evaluating acquisition opportunities and compliance with the Sarbanes-Oxley Act of 2002.

DD&A expense increased primarily as a result of increased production and depreciation on the West Coal River and Bull Creek facilities which began start-up operations in July 2003 and February 2004, respectively.

Interest expense. Interest expense increased primarily due to bridge loan issue costs that were expensed upon the termination of the bridge loan agreement in December 2004 and higher debt levels resulting from the coal handling joint venture investment in July 2004.

Interest income. Interest income decreased primarily due to the declining principal balance on PVR's note receivable.

Minority interest. Minority interest increased primarily due to an increase in the Partnership's net income from 2003 to 2004.

Year Ended December 31, 2003, Compared to Year Ended December 31, 2002

	2003	2002	% Change
	(in thousands, except as noted)		
Revenues			
Coal royalties	$ 50,312	$ 31,358	60%
Coal services	2,111	1,704	24%
Timber	1,020	1,640	(38)%
Other	2,199	3,906	(44)%
Total revenues	55,642	38,608	44%
Expenses			
Operating	4,235	2,912	45%
Taxes other than income	1,256	895	40%
General and administrative	7,013	6,419	9%
Operating expenses before non-cash charges	12,504	10,226	22%
Depreciation, depletion and amortization	16,578	3,955	319%
Total expenses	29,082	14,181	105%
Operating income	26,560	24,427	9%
Interest expense	(4,986)	(1,758)	184%
Interest income and other	1,223	2,017	(39)%
Income from operations before minority interest, income taxes and cumulative effect of change in accounting principle	22,797	24,686	(8)%
Minority interest	(12,510)	(11,896)	5%
Contribution to income from operations before income taxes and cumulative effect of change in accounting principle	$ 10,287	$ 12,790	(20)%
Production			
Royalty coal tons produced by lessees (thousands)	26,463	14,281	85%
Timber sales (Mbf)	5,250	8,345	(37)%
Prices			
Royalty per ton	$ 1.90	$ 2.20	(14)%
Timber sales price per Mbf	$ 179	$ 187	(4)%

Revenues. Coal royalty and land management segment revenues increased primarily due to an increase in coal royalties, partially offset by a decrease in other revenues.

Coal royalty revenues increased due to increased production by lessees, partially offset by a decline in royalty rates. Average gross royalties per ton decreased by 14 percent as a result of the lower royalty rates attributable to our leases with Peabody. Over the same periods, production increased by 12.2 million tons, or 85 percent, primarily due to the following factors:

- Production on the New Mexico property increased by 6.1 million tons, which resulted in an increase in revenues of $9.1 million. The increase was a direct result of the Peabody Acquisition in December 2002.
- Production on the Northern Appalachia property increased by 4.7 million tons, which resulted in an increase in revenues of $5.5 million. The increase was a direct result of the Peabody Acquisition in December 2002 and the Upshur Acquisition in August 2002.
- Production on the Coal River property increased by 1.4 million tons, which resulted in an increase in revenues of $4.2 million. The addition of a mine operator and a new mine by one lessee contributed 0.6 million tons, or $1.7 million in revenues. One lessee mined onto our property from an adjacent property

in 2003, which resulted in an additional 0.6 million tons, or $1.4 million in revenues. The remainder of the increase was primarily due to one lessee beginning operations in late 2002 and reaching full production in 2003 and start-up operations on the West Coal River property. Additional production from two lessees with high royalty rates coupled with increased demand in the region resulted in a 15 percent increase in the average gross royalty per ton on the Coal River property from $2.11 per ton in 2002 to $2.42 per ton in 2003.

- Production on the Wise property increased by 0.4 million tons, which resulted in an increase in revenues of $1.0 million. The increase was primarily due to additional mining equipment being added by two lessees and another lessee beginning operations in late 2002 and reaching full production in 2003.
- Production on the Spruce Laurel property decreased by 0.3 million tons, which resulted in a decrease in revenues of $0.7 million. These decreases were the result of the depletion of two mines in 2003.
- Production on the Buchanan property decreased by 0.1 million tons, which resulted in a $0.2 million decrease in revenues as this property continues to approach the end of its reserve life.

Coal services revenues increased as a direct result of PVR's West Coal River preparation and transloading facility beginning operations in July 2003 and the addition of a small preparation plant.

Timber revenues decreased due to a decreased volume and sales price. The decrease in volume sold was due to the timing of parcel sales.

Other revenues decreased by $1.7 million. The decrease was primarily due to reduction of minimum rental revenues. The decrease in minimum rental revenues was due to a lessee rejecting PVR's lease in bankruptcy in 2002; consequently, $0.8 million of deferred revenues from this respective lessee was recognized as income in 2002. The remainder of the decrease in minimum rental revenues was primarily due to the timing of expiring recoupment from PVR's lessees.

Operating expenses. Operating expenses, which include both lease operating expenses and taxes other than income, increased primarily due to an increase in lease operating expenses, which were $4.2 million for the year ended December 31, 2003, compared to $2.9 million for the year ended December 31, 2002. The increase was primarily due to maintenance costs for idled mines on the West Coal River property. PVR leased its West Coal River property in May 2003, and the on-going maintenance costs were assumed by the new lessee as of that date. The remainder of the variance is primarily attributable to increased production by lessees on subleased properties. Aggregate production from subleased properties increased to 2.0 million tons for the year ended December 31, 2003, from 1.8 million tons for the year ended December 31, 2002. The increase in taxes other than income was attributable to higher property taxes as a result of our assumption of the property tax obligation on the West Coal River property when we took back our lease on this property from the bankrupt lessee. PVR leased the West Coal River property in May 2003, and the on-going property taxes were assumed by the new lessee as of that date.

General and administrative expenses increased primarily due to increased payroll, an increase in insurance premiums, additional recurring expenses associated with the Peabody Acquisition and costs related to the secondary offering of units for Peabody.

DD&A expense increased as a result of higher depletion rates caused by higher cost bases relative to reserves added as well as increased production, both of which related primarily to the Peabody and Upshur Acquisitions completed in the last half of 2002.

Interest expense. Interest expense increased primarily due to the increase in PVR's long-term borrowings in connection with the Peabody Acquisition in December 2002.

Interest income. Interest income decreased primarily due to the liquidation of $43.4 million of U.S. Treasury notes in the last half of 2002, which was used to purchase a portion of the Peabody Acquisition and all of the Upshur Acquisition.

Minority interest. Minority interest increased primarily due to an increase in the public's ownership percentage in the Partnership, offset by a decrease in the Partnership's net income from 2002 to 2003.

Corporate and Other

The Corporate and Other segment primarily consists of miscellaneous revenue from rail car rental fees and oversight and administrative functions.

Selected Financial and Operating Data—Corporate and Other

	2004	2003	2002
	(in thousands, except as noted)		
Revenues			
Other	$ 1,123	$ 820	$ 837
Total revenues	1,123	820	837
Expenses			
Lease operating	600	600	607
Exploration	—	—	166
Taxes other than income	207	551	291
General and administrative	9,527	10,076	6,640
Operating expenses before non-cash charges	10,334	11,227	7,704
Depreciation, depletion and amortization	434	367	348
Total expenses	10,768	11,594	8,052
Operating loss	(9,645)	(10,774)	(7,215)
Interest expense	(405)	(318)	(358)
Interest income and other	38	8	15
Contribution to income from operations before income taxes and cumulative effect of change in accounting principle	$(10,012)	$(11,084)	$(7,558)

Year Ended December 31, 2004, Compared to Year Ended December 31, 2003

Other revenues increased to $1.1 million in 2004 from $0.8 million in 2003 due to increased rail rental income.

Taxes other than income decreased to $0.2 million in 2004 from $0.6 million in 2003 due to a decrease in franchise taxes.

G&A expenses decreased from $10.1 million in 2003 to $9.5 million in 2004, primarily due to the absence in 2004 of consulting and advisory fees incurred in 2003 related to the consideration of various shareholder proposals, offset in part by a general increase in staffing levels, higher insurance premiums and expenses related to compliance with the Sarbanes-Oxley Act of 2002.

Ninety-three percent and 100 percent of direct credit facility interest costs were capitalized during 2004 and 2003, respectively, because the borrowings funded the preparation of unproved properties for their intended use. We capitalized interest costs amounting to $2.0 million in each of 2004 and 2003. Interest costs which were expensed in the corporate and other segment related to the amortization of debt issuance costs.

Year Ended December 31, 2003, Compared to Year Ended December 31, 2002

G&A expenses increased primarily due to consulting and advisory services related to the consideration of various shareholder proposals, higher insurance premiums and a general increase in staffing levels.

In conjunction with the acquisition of oil and gas properties during 2001, considerable unproved leasehold costs were recorded. Interest costs associated with non-producing leases were capitalized during 2003 and 2002 as activities were in progress to bring projects to their intended use. We capitalized $2.0 million and $1.0 million of interest costs in 2003 and 2002, respectively. Interest expense not capitalized in the Corporate and Other segment related to amortization of debt issuance costs.

Reserves

Oil and Gas Reserves

At December 31, 2004, proved developed reserves comprised 74 percent of our total proved reserves, compared with 78 percent at December 31, 2003. We had 257 gross (171 net) proved undeveloped drilling locations at December 31, 2004, compared with 216 gross (152 net) proved undeveloped drilling locations at December 31, 2003.

	Oil and Condensate	Natural Gas	Total Equivalents
	(MMbbls)	(Bcf)	(Bcfe)
Proved reserves			
December 31, 2001	3.9	229.3	252.8
Revisions of previous estimates	—	(3.3)	(3.3)
Extensions, discoveries and other additions	1.9	33.2	44.9
Production	(0.4)	(18.7)	(20.9)
Purchase of reserves	0.1	1.0	1.2
Sale of reserves in place	(0.1)	(0.2)	(1.2)
December 31, 2002	5.4	241.3	273.4
Revisions of previous estimates	0.1	(5.3)	(4.7)
Extensions, discoveries and other additions	0.2	53.1	54.5
Production	(0.6)	(20.1)	(23.8)
Purchase of reserves	1.6	14.3	23.8
Sale of reserves in place	(0.1)	(0.2)	(0.2)
December 31, 2003	6.6	283.1	322.9
Revisions of previous estimates	(0.4)	(13.7)	(16.2)
Extensions, discoveries and other additions	0.5	70.0	73.2
Production	(0.4)	(22.0)	(24.5)
Purchase of reserves	—	—	—
Sale of reserves in place	(0.0)	(1.3)	(1.3)
December 31, 2004	6.3	316.1	354.1
Proved developed reserves			
December 31, 2002	2.9	198.7	216.4
December 31, 2003	3.3	231.0	251.0
December 31, 2004	2.9	243.5	260.9

	2004	2003	2002
Reserve replacement percentage(a)			
Current year	233%	308%	206%
Three year weighted average	250%	357%	432%

(a) Reserve replacement percentage is calculated by dividing 1) reserve purchases, revisions, extensions, discoveries and other additions, by 2) oil and gas production.

Proven and Probable Coal Reserves

The Partnership's proven and probable coal reserves were 558 million tons at December 31, 2004, compared with 588 million tons at December 31, 2003. Royalties were collected for 31.2 million tons mined on the Partnership's properties in 2004.

Capital Resources and Liquidity

Although results are consolidated for financial reporting, the Company and PVR operate with independent capital structures. The Company and PVR have separate credit facilities, and neither entity guarantees the debt of the other. Since PVR's inception in 2001, with the exception of cash distributions received by the Company from PVR, the cash needs of each entity have been met independently with a combination of operating cash flows, credit facility borrowings and, in the case of PVR's Peabody Acquisition, issuance of new partnership units. We expect that our cash needs and the cash needs of PVR will continue to be met independently of each other with a combination of these funding sources. Below are summarized cash flow statements for 2004 and 2003 consolidating the oil and gas (and corporate) and the coal royalty and land management (PVR) segments.

For the year ended December 31, 2004 (in thousands)	Oil and Gas & Corporate	Coal Royalty & Land Mgmt (PVR)	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 24,115	$ 9,240	$ 33,355
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	82,974	39,661	122,635
Net change in operating assets and liabilities	(15,506)	5,881	(9,625)
Net cash provided by operating activities	91,583	54,782	146,365
Cash flows from investing activities:			
Additions to property and equipment	(124,153)	(1,088)	(125,241)
Acquisitions	—	(28,442)	(28,442)
Other	1,222	1,104	2,326
Net cash used in investing activities	(122,931)	(28,426)	(151,357)
Cash flows from financing activities:			
PVA dividends paid	(8,248)	—	(8,248)
PVR distributions received/(paid)	17,299	(39,191)	(21,892)
PVA debt proceeds, net of repayments	12,000	—	12,000
PVR debt proceeds, net of repayments	—	26,000	26,000
Other	5,829	(1,234)	4,595
Net cash provided by (used in) financing activities	26,880	(14,425)	12,455
Net increase, (decrease) in cash and cash equivalents	(4,468)	11,931	7,463
Cash and cash equivalents—beginning of year	8,942	9,066	18,008
Cash and cash equivalents—end of year	$ 4,474	$ 20,997	$ 25,471

For the year ended December 31, 2003 (in thousands)	Oil and Gas & Corporate	Coal Royalty & Land Mgmt (PVR)	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 22,455	$ 6,067	$ 28,522
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	55,552	29,673	85,225
Net change in operating assets and liabilities	(9,380)	5,337	(4,043)
Net cash provided by operating activities	68,627	41,077	109,704
Cash flows from investing activities:			
Additions to property and equipment	(122,891)	(5,291)	(128,182)
Other	800	580	1,380
Net cash used in investing activities	(122,091)	(4,711)	(126,802)
Cash flows from financing activities:			
PVA dividends paid	(8,092)	—	(8,092)
PVR distributions received/(paid)	16,828	(36,708)	(19,880)
PVA debt proceeds, net of repayments	47,948	—	47,948
PVR debt proceeds, net of repayments	—	1,613	1,613
Other	2,001	(1,825)	176
Net cash provided by (used in) financing activities	58,685	(36,920)	21,765
Net increase, (decrease) in cash and cash equivalents	5,221	(554)	4,667
Cash and cash equivalents—beginning of year	3,721	9,620	13,341
Cash and cash equivalents—end of year	$ 8,942	$ 9,066	$ 18,008

Except where noted, the following discussion of cash flows and contractual obligations relates to consolidated results of the Company and PVR.

Cash Flows from Operating Activities

The oil and gas and corporate segments' net cash provided by operations increased primarily due to increased prices received for, and higher production of, natural gas and crude oil. We used cash in excess of working capital needs during both years to help fund the respective year's capital expenditures. Cash provided by operations of the coal royalty and land management segment increased primarily due to increased production attributable to a longwall mining operation located on one of PVR's properties, coupled with an increase in average royalties per ton resulting from higher coal sales prices.

Cash Flows from Investing Activities

During 2004 and 2003, we used cash primarily for capital expenditures for oil and gas development and exploration activities and acquisitions of oil and gas properties. During 2004, PVR acquired an interest in the Massey Energy Company coal handling joint venture for $28.4 million.

Capital expenditures totaled $137.5 million in 2004, compared with $138.8 million in 2003 and $203.8 million in 2002. The following table sets forth capital expenditures by segment, made during the periods indicated.

	Year ended December 31,		
	2004	2003	2002
		(in thousands)	
Oil and gas			
Development drilling	$ 77,033	$ 59,551	$ 39,014
Exploration drilling	16,411	11,931	2,485
Seismic and other	10,018	9,470	5,358
Lease acquisitions(a)	13,046	44,152	6,336
Field projects	18,669	7,770	2,736
Total	135,177	132,874	55,929
Coal royalty and land management (PVR)			
Lease acquisitions(b)	1,293	6,330	138,450
Support equipment and facilities	855	4,128	9,085
Total	2,148	10,458	147,535
Other	176	621	343
Total capital expenditures	$137,501	$143,953	$203,807

(a) Amount in 2003 includes $33.5 million to acquire proved oil and gas properties in south Texas.

(b) Amounts in 2004, 2003 and 2002 include noncash expenditures of $1.1 million, $5.2 million and $54.7 million, respectively, to acquire additional reserves on PVR's northern Appalachia properties in exchange for equity issued in the form of PVR common and Class B units in connection with PVR's Peabody Acquisition.

We are committed to expanding our oil and natural gas operations over the next several years through a combination of exploration, development and acquisition of new properties. We have a portfolio of assets which balances relatively low risk, moderate return development projects in Appalachia and Mississippi with relatively moderate risk, potentially higher return development projects and exploration prospects in south Texas and south Louisiana.

We estimate oil and gas segment capital expenditures for 2005 to be approximately $146 million. We expect to use approximately $85 million of the planned oil and gas capital expenditures for development drilling projects, including horizontal CBM and conventional drilling in Appalachia, our Mississippi Selma Chalk assets and drilling Cotton Valley wells in east Texas and north Louisiana. We expect to use approximately $25 million of the planned expenditures on exploration drilling, concentrated primarily in south Louisiana and south Texas. We expect to use approximately $7 million to build our library of 3-D seismic data and approximately $29 million for lease acquisition and field project expenditures. We continually review drilling and other capital expenditure plans and may change these amounts based on industry conditions and the availability of capital. We believe our cash flow from operations and sources of debt financing are sufficient to fund our 2005 planned capital expenditures program.

During the first quarter of 2005, PVR made capital expenditures of approximately $191 million, plus closing fees and adjustments, for the Cantera Acquisition. The acquisition was funded with a new $260 million credit facility as described in the following section, "Cash Flows from Financing Activities."

Cash Flows from Financing Activities

PVA borrowed under its credit facility approximately $12.0 million of cash in 2004 and $47.9 million of cash in 2003. We also received from PVR $17.3 million of cash distributions in 2004 and $16.8 million of cash distributions in 2003. Funds from both of these sources were primarily used for capital expenditure needs.

The Company has a revolving credit facility (the "Revolver") with a syndicate of major banks led by JP Morgan Chase Bank N.A. (as the Administrative Agent), with a final maturity of December 2007. The Revolver is secured by a portion of our proved oil and gas reserves. It has an initial commitment of $150 million which can be expanded at our option to our current approved borrowing base of $200 million. The Company had borrowings of $76 million against the Revolver as of December 31, 2004, giving us approximately $74 million of borrowing capacity available under the Revolver as of that date. The Revolver is governed by a borrowing base calculation and will be redetermined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.25 to 2.00 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin ranging from 0.30 to 0.50 percent. The Revolver allows for issuance of up to $20 million of letters of credit. At December 31, 2004, letters of credit issued were $0.3 million. The financial covenants require us to maintain levels of debt-to-earnings and impose dividend limitation restrictions. At December 31, 2004, we were in compliance with all of our covenants.

We have a $5 million line of credit, which had no borrowings against it as of December 31, 2004. The line of credit is effective through June 2005 and is renewable annually. We have an option to elect either a fixed rate LIBOR loan, floating rate LIBOR loan or base rate (as determined by the financial institution) loan.

As of December 31, 2004, the Partnership had outstanding borrowings of $117.7 million, consisting of $30.0 million borrowed against a revolving credit facility and $87.7 million attributable to the Partnership's senior unsecured notes ($88.5 million offset by $0.8 million fair value of interest rate swap).

As of December 31, 2004, the Partnership had a revolving credit facility (the "PVR Revolver") of $100 million maturing in October 2006. The PVR Revolver is with a syndicate of financial institutions led by PNC Bank, National Association, as its agent. Available borrowing capacity under the PVR Revolver as of December 31, 2004, was approximately $38.6 million. The Revolver is available for general partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $5.0 million sublimit available for working capital needs and distributions and a $5.0 million sublimit for the issuance of letters of credit.

Concurrent with the closing of the Cantera Acquisition, PVR entered into a new unsecured $260 million, five-year credit facility with an expanded bank group led by PNC Capital Markets and RBC Capital Markets. The new credit facility consists of a $150 million revolving credit facility and a $110 million term loan. The term loan and a portion of the revolving credit facility were used to fund the Cantera Acquisition and to repay borrowings under the PVR Revolver. The new revolving credit facility is available for general partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. PVR has a one-time option under the revolving credit facility to increase the facility by up to $100 million upon receipt by the lenders' administrative agent of commitments from one or more existing or new lenders. Once repaid, the term loan cannot be re-borrowed. The term loan will be payable as interest only until March 3, 2006, and then will be payable in 16 equal quarterly payments plus any accrued interest if not repaid before that date.

The interest rate on the new credit facility will fluctuate based on PVR's ratio of total indebtedness to EBITDA. At our option, interest is payable at the alternative base rate plus an applicable margin ranging from 0.00 percent to 2.00 percent or the London Interbank Offering Rate plus an applicable margin ranging from 1.00 percent to 2.00 percent.

As of December 31, 2004, PVR owed $88.5 million under its a private placement of $90 million of senior unsecured notes payable (the "PVR Notes"). The PVR Notes bore interest at a fixed rate of 5.77 percent and mature over a ten-year period ending in March 2013, with semi-annual interest payments through March 2004 followed by semi-annual principal and interest payments beginning in September 2004. At December 31, 2004, PVR was in compliance with the covenants in the Notes. In November 2004, PVR's investment grade debt rating of BBB (low) was confirmed by Dominion Bond Rating Services, an accredited bond rating agency.

Concurrent with the closing of the Cantera Acquistion, PVR amended the Notes to allow PVR to enter the midstream natural gas business and to increase certain covenant coverage ratios, including the ratio of PVR's consolidated indebtedness to consolidated EBITDA (as defined in the Notes). In exchange for this amendment, PVR agreed to a 0.25 percent increase in the fixed interest rate on the Notes, from 5.77 percent to 6.02 percent. The amendment to the Notes also requires that PVR obtain an annual confirmation of its credit rating, with a 1.00 percent increase in the interest rate payable on the Notes in the event PVR's credit rating falls below investment grade.

In conjunction with the PVR Notes, the Partnership entered into an interest rate swap agreement with a notional amount of $29.5 million, to hedge a portion of the fair value of the PVR Notes. This swap is designated as a fair value hedge and has been reflected as a decrease in long-term debt of $0.8 million as of December 31, 2004, with a corresponding increase in other liabilities. Under the terms of the interest rate swap agreement, the counterparty pays the Partnership a fixed annual rate of 5.77 percent on a total notional amount of $29.5 million, and the Partnership pays the counterparty a variable rate equal to the floating interest rate which is determined semi-annually and is based on the six month London Interbank Offering Rate plus 2.36 percent.

Future Capital Needs and Commitments. In 2005, we anticipate making total capital expenditures, excluding acquisitions, of approximately $149 million. Nearly all of these expenditures are expected to be made in our oil and gas segment, and are expected to be funded primarily by operating cash flow. Additional funding will be provided as needed from our Revolver, under which we had $74 million of borrowing capacity as of December 31, 2004.

In connection with PVR's Cantera Acquisition, during the fourth quarter of 2004, the Partnership entered into a bridge loan commitment with two financial institutions. The bridge loan was terminated late in the fourth quarter of 2004, and PVR replaced it with an expanded credit facility concurrent with the closing of the Cantera Acquisition. PVR anticipates using a combination its credit facility and new equity capital to permanently finance the Cantera Acquisition. The Partnership also anticipates 2005 capital expenditures of $0.3 million for coal services related projects and other property and equipment, which it believes can be funded with cash flow provided by operating activities. Limitations in the availability of debt financing may necessitate the issuance of new units, as opposed to using debt, to provide a large part of the funding for acquisitions in the future.

Our contractual cash obligations as of December 31, 2004, were as follows:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	4-5 Years	Thereafter
			(in thousands)		
Penn Virginia Corporation Revolver	$ 76,000	$ —	$ 76,000	$ —	$ —
PVR Revolver	30,000	—	30,000	—	—
PVR Notes	88,500	4,800	19,300	26,800	37,600
Rental commitments(1)	5,419	1,607	2,984	828	—
Firm transportation agreements	12,333	1,479	3,378	2,162	5,314
Total contractual cash obligations	$212,252	$7,886	$131,662	$29,790	$42,914

(1) Rental commitments primarily relate to equipment and building leases. Also included are PVR's rental commitments, which primarily relate to reserve-based properties which are, or are intended to be, subleased by the Partnership to third parties. The obligation expires when the property has been mined to exhaustion or the lease has been canceled. The timing of mining by third party operators is difficult to estimate due to numerous factors. We believe the obligation after five years cannot be reasonably estimated; however, based on current knowledge, we believe PVR will incur approximately $0.4 million in rental commitments in perpetuity until the reserves have been exhausted.

Environmental Matters

Our businesses are subject to various environmental hazards. Numerous federal, state and local laws, regulations and rules govern the environmental aspects of our businesses. Noncompliance with these laws, regulations and rules can result in substantial penalties or other liabilities. We do not believe our environmental risks are materially different from those of comparable companies or that cost of compliance will have a material adverse effect on our profitability, capital expenditures, cash flows or competitive position.

However, there is no assurance that future changes in or additions to laws, regulations or rules regarding the protection of the environment will not have such an impact. We believe we are materially in compliance with environmental laws, regulations and rules.

In conjunction with the Partnership's leasing of property to coal operators, environmental and reclamation liabilities are generally the responsibilities of the Partnership's lessees. Lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary.

Recent Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," under which PVR classified leased coal mineral rights as intangible assets. In April 2004, the FASB issued a FASB Staff Position ("FSP") that amends certain sections of SFAS No. 141 and No. 142 relating to the characterization of coal mineral rights. As allowed by the FSP, the Partnership early adopted the FSP in April 2004 and, accordingly, reclassified its leased coal mineral rights back to tangible property. The Partnership discontinued straight-line amortization upon adoption and will deplete its coal mineral rights using the units-of-production method on a prospective basis. The amount capitalized related to a mineral right represents its fair value at the time such right was acquired, less accumulated amortization. Pursuant to the FSP, for comparative presentation purposes, $4.9 million was reclassified from a separate line item in other noncurrent assets to net property and equipment as of December 31, 2003, on the accompanying consolidated balance sheet.

In September 2004, the FASB issued another FSP to clarify that the scope exception in paragraph 8(b) of SFAS No. 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing companies. Therefore, our historical practice of including the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties under SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," has been affirmed by the new FSP.

The FASB issued FSP SFAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," in May 2004, effective for the first interim or annual period beginning after June 15, 2004. The FSP requires employers that qualify for a prescription-drug subsidy under Medicare legislation enacted in December 2003 to recognize the reduction in costs as employees provide services in future years. We adopted FSP SFAS 106-2 on July 1, 2004, and it did not have a significant impact on our financial statements. As a result of the Medicare Prescription Drug, Improvement and Modernization Act of 2003, our accumulated postretirement benefit obligation as of January 1, 2004, decreased by $0.4 million.

In December 2004, the FASB issued a revised version of SFAS No. 123, "Share-Based Payment," which requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. SFAS No. 123 will be effective for the first interim or annual period beginning after June 15, 2005. At that time, we will be required to begin recognizing compensation expense for the unvested portion of outstanding options. We are currently assessing the effect of the revised SFAS No. 123 on our financial statements.

SFAS No. 153, "Exchanges of Productive Assets," was also issued in December 2004 and requires that nonmonetary exchanges of assets be accounted for at fair value, recognizing any gain or loss, subject to certain criteria. Before this new rule, companies were permitted to account for nonmonetary exchanges at book value. SFAS No. 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. This new pronouncement is not expected to have a material effect on our financial statements.

Forward-Looking Statements

Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions related thereto) are forward-looking. In addition, we and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

The Company cautions that forward-looking statements are not guarantees of future performance and that actual results could differ materially from those expressed or implied in the forward-looking statements, since those statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and PVR and, therefore, involve a number of risks, uncertainties and contingencies. These risks, uncertainties and contingencies include, but are not limited to, the following:

- the cost of finding and successfully developing oil and gas reserves and the cost to PVR of finding new coal reserves;
- our ability to acquire new oil and gas reserves and PVR's ability to acquire new coal reserves on satisfactory terms;
- the price for which such reserves can be acquired;
- the volatility of commodity prices for crude oil, natural gas and coal;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production;
- PVR's ability to lease new and existing coal reserves;
- the ability of PVR's lessees to produce sufficient quantities of coal on an economic basis from PVR's reserves;

- the ability of lessees to obtain favorable contracts for coal produced from PVR's reserves;
- PVR's ability to integrate and manage its new midstream business;
- whether PVR's Cantera Acquisition will be accretive to cash flow;
- competition among producers in the oil and gas, coal and pipeline industries generally;
- the extent to which the amount and quality of actual production differs from estimated recoverable proved oil and gas reserves and coal reserves;
- unanticipated geological problems;
- availability of required drilling rigs, materials and equipment;
- the occurrence of unusual weather or operating conditions including force majeure events;
- the failure of equipment or processes to operate in accordance with specifications or expectations;
- delays in anticipated start-up dates of our oil and natural gas production and PVR's lessees' mining operations and related coal infrastructure projects;
- environmental risks affecting the drilling and producing of oil and gas wells or the mining of coal reserves;
- the timing of receipt of necessary governmental permits by us and by PVR's lessees;
- the risks associated with having or not having price risk management programs;
- labor relations and costs;
- accidents;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators;
- uncertainties relating to the outcome of litigation regarding permitting of the disposal of coal overburden;
- risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions (including the impact of potential terrorist attacks);
- the experience and financial condition of lessees of PVR's coal reserves including their ability to satisfy their royalty, environmental, reclamation and other obligations to PVR and others; and
- the Partnership's ability to make cash distributions.

Many of such factors are beyond our ability to control or predict. Readers are cautioned not to put undue reliance on forward-looking statements.

While we periodically reassess material trends and uncertainties affecting our results of operations and financial condition in connection with the preparation of Management's Discussion and Analysis of Results of Operations and Financial Condition and certain other sections contained in our quarterly, annual and other reports filed with the SEC, we do not undertake any obligation to review or update any particular forward-looking statement, whether as a result of new information, future events or otherwise.

Item 7A—*Quantitative and Qualitative Disclosures about Market Risk*

Interest Rate Risk. At December 31, 2004, we had $76.0 million of long-term debt borrowed against our Revolver. The Revolver matures in December 2007 and is governed by a borrowing base calculation that is re-determined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.25 to 2.00 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin ranging from 0.30 to 0.50 percent. As a result, our 2005 interest costs will fluctuate based on short-term interest rates relating to the PVA Revolver.

As of December 31, 2004, $88.5 million of PVR's borrowings were financed with debt which has a fixed interest rate throughout its term. In connection with this financing, PVR executed an interest rate derivative transaction to effectively convert the interest rate on one-third of the amount financed from a fixed rate of 5.77 percent to a floating rate of LIBOR plus 2.36 percent. The interest rate swap has been accounted for as a fair value hedge in compliance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS No. 137 and SFAS No. 138.

Price Risk Management. Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to mitigate the price risks associated with fluctuations in natural gas and crude oil prices as they relate to our anticipated production. These financial instruments are designated as cash flow hedges and accounted for in accordance with SFAS No. 133, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 139. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair value of our price risk management assets are significantly affected by energy price fluctuations. See the discussion and tables in Note 9, "Hedging Activities" of the Notes to the Consolidated Financial Statements for a description of our hedging program and a listing of open hedging contracts and their fair value.

In connection with the Cantera Acquisition, PVR entered into notional derivative contracts in January 2005 for approximately 75 percent of the net volume of natural gas liquids expected to be sold from April 2005 through December 2006. The underlying commodity prices that PVR expects to realize in future periods, after giving effect to the derivative contracts, are expected to exceed the commodity prices used in financial evaluation of the acquisition.

Since the time PVR entered into the derivative contracts, futures prices of natural gas liquids have increased significantly. As of March 2, 2005, the aggregate fair value of these derivative contracts was unfavorable to PVR. Upon closing of the Cantera Acquisition and documenting hedge effectiveness, these derivative contracts are expected to qualify as cash flow hedges in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," ("SFAS No. 133"). (See our previous discussion of hedging activities in "Critical Accounting Policies and Estimates.") From the time the derivative contracts were executed until completion of the hedge effectiveness documentation, the derivative contracts do not qualify for hedge accounting. The unfavorable change in the derivative contracts' fair value was estimated to be approximately $8.9 million as of March 2, 2005. The fair value at the date the derivative contracts qualify for hedge accounting will be recognized as a non-cash reduction of earnings for PVR in the first quarter of 2005. The $8.9 million as of March 2, 2005, is the most recently available fair value estimate and is subject to change until the derivative contracts qualify for hedge accounting. All cash settlements of these derivative contracts will be paid or received over the 21-month term of the contracts.

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

March 8, 2005	By:	/s/ FRANK A. PICI
		(Frank A. Pici, Executive Vice President and Chief Financial Officer)
March 8, 2005	By:	/s/ DANA G WRIGHT
		(Dana G Wright, Vice President and Principal Accounting Officer)

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.

/s/ ROBERT GARRETT **(Robert Garrett)**	Chairman of the Board and Director	March 8, 2005
/s/ JOE N. AVERETT, JR. **(Joe N. Averett, Jr.)**	Director	March 8, 2005
/s/ EDWARD B CLOUES, II **(Edward B. Cloues, II)**	Director	March 8, 2005
/s/ A. JAMES DEARLOVE **(A. James Dearlove)**	Director and Chief Executive Officer	March 8, 2005
/s/ KEITH D. HORTON **(Keith D. Horton)**	Director and Executive Vice President	March 8, 2005
/s/ STEVEN W. KRABLIN **(Steven W. Krablin)**	Director	March 8, 2005
/s/ MARSHA R. PERELMAN **(Marsha R. Perelman)**	Director	March 8, 2005
/s/ GARY K. WRIGHT **(Gary K. Wright)**	Director	March 8, 2005

Item 8—*Financial Statements and Supplementary Data*

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

INDEX TO FINANCIAL SECTION

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, a Virginia corporation, and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the 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, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 12 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Penn Virginia Corporation's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 7, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of internal control over financial reporting and an adverse opinion on the effectiveness of internal control over financial reporting because of the existence of a material weakness.

KPMG LLP

Houston, Texas
March 7, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited Management's Assessment on Internal Control Over Financial Reporting, appearing under Item 9A, that Penn Virginia Corporation, a Virginia corporation, and its subsidiaries (the Company) did not maintain effective internal control over financial reporting as of December 31, 2004, because of the effect of the material weakness identified in management's assessment based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management's assessment:

> During the course of our audit of the Company's consolidated financial statements as of and for the year ended December 31, 2004, we discovered that the Company incorrectly calculated the loss associated with the sale of certain assets, which were previously classified as assets being held for sale. The Company agreed that it incorrectly calculated the loss on the asset sale and recorded the correcting entry in its consolidated financial statements. The accounting error was the result of a lack of sufficient review by appropriate company personnel of the accounting for non-routine transactions. This deficiency constituted a material weakness in the Company's internal control over financial reporting as of December 31, 2004.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2004 and 2003 and the related consolidated statements of income, stockholders' equity and comprehensive income, and cash flows for each of the years in the three year period ended December 31, 2004 of the Company. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2004 consolidated financial statements, and this report does not affect our report dated March 7, 2005, which expressed an unqualified opinion on those consolidated financial statements.

In our opinion, management's assessment that Penn Virginia Corporation did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also, in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

KPMG LLP

Houston, Texas
March 7, 2005

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except share data)

	Year Ended December 31, 2004	2003	2002
Revenues			
Oil and condensate	$ 13,364	$ 16,816	$ 8,246
Natural gas	138,422	106,615	62,552
Coal royalties	69,643	50,312	31,358
Coal services	3,391	2,111	1,704
Timber	702	1,020	1,640
Other	2,903	4,410	5,457
	228,425	181,284	110,957
Expenses			
Lease operating	21,773	16,864	12,754
Exploration	26,058	15,589	7,733
Taxes other than income	10,480	11,322	6,804
General and administrative	26,170	24,893	21,440
Depreciation, depletion and amortization	54,952	50,109	30,639
Loss on assets held for sale	7,541	—	—
Impairment of oil and gas properties	655	406	796
	147,629	119,183	80,166
Operating Income	80,796	62,101	30,791
Other income (expense)			
Interest expense	(7,672)	(5,304)	(2,116)
Interest income and other	1,101	1,238	2,039
Income from continuing operations before minority interest, income taxes, discontinued operations and cumulative effect of change in accounting principle	74,225	58,035	30,714
Minority interest	19,023	12,510	11,896
Income tax expense	21,847	18,366	6,935
Income from continuing operations before discontinued operations and cumulative effect of change in accounting principle	33,355	27,159	11,883
Income from discontinued operations (including gain on sale and net of taxes)	—	—	221
Cumulative effect of change in accounting principle, net of taxes of $734 thousand	—	1,363	—
Net Income	$ 33,355	$ 28,522	$ 12,104
Income from continuing operations before discontinued operations and cumulative effect of change in accounting principle, basic	$ 1.82	$ 1.51	$ 0.67
Income from discontinued operations, basic	—	—	0.01
Cumulative effect of change in accounting principle, basic	—	0.08	—
Net income per share, basic	$ 1.82	$ 1.59	$ 0.68
Income from continuing operations before discontinued operations and cumulative effect of change in accounting principle, diluted	$ 1.81	$ 1.50	$ 0.66
Income from discontinued operations per share, diluted	—	—	0.01
Cumulative effect of change in accounting principle, diluted	—	0.08	—
Net income per share, diluted	$ 1.81	$ 1.58	$ 0.67
Weighted average shares outstanding, basic	18,306	17,976	17,860
Weighted average shares outstanding, diluted	18,467	18,112	17,948

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2004	December 31, 2003
Assets		
Current assets		
Cash and cash equivalents	$ 25,471	$ 18,008
Accounts receivable	40,003	25,275
Income taxes receivable	4,389	6,514
Assets held for sale	9,694	—
Other	4,682	2,108
Total current assets	84,239	51,905
Property and equipment		
Oil and gas properties (successful efforts method)	591,100	503,290
Other property and equipment	274,191	272,447
	865,291	775,737
Less: Accumulated depreciation, depletion and amortization	199,803	149,934
Net property and equipment	665,488	625,803
Equity investments	27,881	—
Other assets	5,727	6,025
Total assets	$ 783,335	$ 683,733
Liabilities and Shareholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 4,800	$ 1,500
Accounts payable	8,899	9,911
Accrued liabilities	26,353	19,153
Hedging liabilities	1,723	2,678
Total current liabilities	41,775	33,242
Other liabilities	18,095	15,188
Hedging liabilities	876	998
Deferred income taxes	97,912	77,863
Long-term debt of the Company	76,000	64,000
Long-term debt of PVR	112,926	90,286
Minority interest in PVR	182,891	190,508
Commitments and contingencies (Note 22)		
Shareholders' equity		
Preferred stock of $100 par value—100,000 authorized shares; none issued	—	—
Common stock of $0.01 par value at December 31, 2004, and $6.25 par value at December 31, 2003—32,000,000 shares authorized; 18,476,331 and 18,104,832 shares issued and outstanding at December 31, 2004 and 2003, respectively (9,052,416 pre-split shares issued and outstanding at December 31, 2003)	185	56,576
Paid-in capital	85,543	14,497
Retained earnings	168,726	143,619
Accumulated other comprehensive income	(720)	(2,250)
	253,734	212,442
Less: Unearned compensation and ESOP	(874)	(794)
Total shareholders' equity	252,860	211,648
Total liabilities and shareholders' equity	$ 783,335	$ 683,733

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(in thousands, except share data)

	Shares Outstanding	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Unearned Compensation And ESOP	Total Stockholders' Comprehensive Equity	Comprehensive Income (Loss)
Balance at December 31, 2001	17,796,202	$ 55,762	$ 9,869	$119,125	$ 1,756	$(599)	$(459)	$185,454	
Dividends paid ($0.45 per share)	—	—	—	(8,040)	—	—	—	(8,040)	
Purchase of treasury stock	(30,404)	—	—	—	—	(557)	—	(557)	
Stock issued as compensation	13,504	8	84	—	—	157	—	249	
PVR units issued as compensation, net	—	—	806	—	—	—	(664)	142	
Exercise of stock options	114,000	145	470	—	—	999	—	1,614	
Allocation of ESOP shares	—	—	207	—	—	—	200	407	
Net income	—	—	—	12,104	—	—	—	12,104	$12,104
Other comprehensive loss, net of tax	—	—	—	—	(3,417)	—	—	(3,417)	(3,417)
Balance at December 31, 2002	17,893,302	55,915	11,436	123,189	(1,661)	—	(923)	187,956	$ 8,687
Dividends paid ($0.45 per share)	—	—	—	(8,092)	—	—	—	(8,092)	
Stock issued as compensation	13,420	42	229	—	—	—	—	271	
PVR units issued as compensation, net	—	—	172	—	—	—	(71)	101	
Exercise of stock options	198,110	619	2,364	—	—	—	—	2,983	
Allocation of ESOP shares	—	—	296	—	—	—	200	496	
Net income	—	—	—	28,522	—	—	—	28,522	$28,522
Other comprehensive loss, net of tax	—	—	—	—	(589)	—	—	(589)	(589)
Balance at December 31, 2003	18,104,832	56,576	14,497	143,619	(2,250)	—	(794)	211,648	$27,933
Dividends paid ($0.45 per share)	—	—	—	(8,248)	—	—	—	(8,248)	
Recognition of gain on conversion of subordinated PVR units to common	—	—	6,393	—	—	—	—	6,393	
Stock issued as compensation	7,099	—	239	—	—	—	—	239	
PVR units issued as compensation, net	—	—	440	—	—	—	(139)	301	
Vesting of restricted units	—	—	(354)	—	—	—	—	(354)	
Exercise of stock options	364,400	4	7,814	—	—	—	—	7,818	
Allocation of ESOP shares	—	—	119	—	—	—	59	178	
Change in par value	—	(56,395)	56,395	—	—	—	—	—	
Net income	—	—	—	33,355	—	—	—	33,355	$33,355
Other comprehensive gain, net of tax	—	—	—	—	1,530	—	—	1,530	1,530
Balance at December 31, 2004	18,476,331	$ 185	$85,543	$168,726	$ (720)	$ —	$(874)	$252,860	$34,885

See accompanying notes to consolidated financial statements

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31,		
	2004	2003	2002
Cash flows from operating activities:			
Net income	$ 33,355	$ 28,522	$ 12,104
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	54,952	50,109	30,639
Deferred income taxes	19,225	15,292	8,133
Minority interest	19,023	12,510	11,896
Dry hole and unproved leasehold expense	16,010	5,989	2,255
Impairment of oil and gas properties	655	406	796
Loss on assets held for sale	7,541	—	—
Cumulative effect of change in accounting principle	—	(1,363)	—
Other	5,229	2,282	1,975
Changes in operating assets and liabilities:			
Accounts receivable	(12,603)	(11,423)	(5,695)
Other current assets	(1,781)	239	(646)
Accounts payable and accrued liabilities	2,996	4,785	6,849
Other assets and liabilities	1,763	2,356	(2,518)
Net cash flows provided by operating activities	146,365	109,704	65,788
Cash flows from investing activities:			
Proceeds from the sale of property and equipment	1,559	850	1,319
Payments received on long-term notes receivable	767	530	555
Sale of restricted U. S. Treasury Notes	—	—	43,387
Acquisitions	(28,442)	—	—
Additions to property and equipment	(125,241)	(128,182)	(144,741)
Net cash flows used in investing activities	(151,357)	(126,802)	(99,480)
Cash flows from financing activities:			
Dividends paid	(8,248)	(8,092)	(8,040)
Distributions paid to minority interest holders of PVR	(21,892)	(19,880)	(13,787)
Proceeds from borrowings of the Company	33,000	108,398	22,046
Repayment of borrowings of the Company	(21,000)	(60,450)	(10,729)
Proceeds from PVR borrowings	28,500	90,000	47,500
Repayments of PVR borrowings	(2,500)	(88,387)	—
Payments for debt issuance costs	(1,234)	(2,824)	—
Purchases of treasury stock	—	—	(557)
Purchase of PVR units	—	—	(1,067)
Issuance of stock and other	5,829	3,000	2,046
Net cash flows provided by financing activities	12,455	21,765	37,412
Net increase in cash and cash equivalents	7,463	4,667	3,720
Cash and cash equivalents—beginning of year	18,008	13,341	9,621
Cash and cash equivalents—end of year	$ 25,471	$ 18,008	$ 13,341
Supplemental disclosures:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 5,790	$ 3,810	$ 1,213
Income taxes	$ 4,148	$ 6,529	$ 125
Noncash investing and financing activities:			
Issuance of PVR units for acquisitions	$ 1,060	$ 4,969	$ 50,920
Working capital and assumed liabilities for acquisitions, net	$ —	$ —	$ 3,805

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia" or the "Company") is an independent energy company that is engaged in two primary lines of business. We explore for, develop and produce crude oil, condensate and natural gas in the eastern and Gulf Coast onshore areas of the United States. In addition, we conduct our coal royalty and land management operations through our ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"), a Delaware limited partnership. See Note 2, "Penn Virginia Resource Partners, L.P."

The Partnership enters into leases with various third-party operators that give those operators the right to mine coal reserves on the Partnership's property, located in the Appalachian region of the United States and New Mexico, in exchange for royalty payments. The lessees make payments to the Partnership based on either a fixed rate per ton of coal sold, with pre-established annual minimum payments, or the higher of a percentage of the gross sales price or a fixed price per ton of coal sold, with pre-established minimum monthly or annual payments. The Partnership also sells timber growing on its land and provides fee-based infrastructure facilities to certain lessees and other third party institutional end-users to enhance coal production and to generate additional coal services revenues.

2. Penn Virginia Resource Partners, L.P.

Penn Virginia Resource Partners, L.P. was formed in July 2001 to own and operate the coal land management business of Penn Virginia. The Partnership completed an initial public offering ("IPO") in October 2001. Effective with the closing of the initial public offering, Penn Virginia, through its wholly owned subsidiaries, received common and subordinated units and a two percent general partnership interest in the ownership of the Partnership. The general partner of the Partnership is Penn Virginia Resource, GP, LLC, a wholly owned subsidiary of Penn Virginia.

The common units have preferences over the subordinated units with respect to cash distributions; accordingly, we accounted for the sale of the Partnership units as a sale of a minority interest. At the time of the IPO, we computed a gain of $25.6 million under Staff Accounting Bulletin No. 51, "Accounting for Sales of Stock by a Subsidiary," which is included in minority interest. As our subordinated units convert to common units, we will recognize the gain calculated at the time of the IPO as paid-in capital. All subordinated units automatically convert to common units on September 30, 2006, but 25 percent of the subordinated units converted in November 2004 as the Partnership met certain requirements to qualify for early conversion. Another 25 percent may convert after September 30, 2005, if the Partnership meets the requirements. In the fourth quarter of 2004, $6.4 million of the $25.6 million gain was reclassified from minority interest to paid-in capital upon the conversion of 25 percent of the subordinated units.

3. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Penn Virginia, all wholly-owned subsidiaries and the Partnership in which we have an approximate 44.5 percent ownership interest as of December 31, 2004. Penn Virginia Resource GP, LLC, a wholly-owned subsidiary of Penn Virginia, serves as the Partnership's sole general partner and controls the Partnership. We own and operate our undivided oil and gas reserves through our wholly-owned subsidiaries. We account for our undivided interest in oil and gas properties using the proportionate consolidation method, whereby our share of assets, liabilities, revenues and expenses is included in the appropriate classification in the financial statements. Intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, all adjustments have been reflected that are necessary for a fair presentation of the consolidated financial statements. Certain amounts have been reclassified to conform to the current year's presentation.

Use of Estimates

Preparation of the accompanying 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 the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

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

Oil and Gas Properties

We use the successful efforts method of accounting for our oil and gas operations. Under this method of accounting, costs to acquire mineral interests in oil and gas properties and to drill and equip development wells (including development dry holes) are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Other exploration costs, including annual delay rentals and geological and geophysical costs, are charged to expense when incurred. Pursuant to Statement of Financial Accounting Standards ("SFAS") No. 19, "Financial Accounting and Reporting by Oil and Gas Reporting Companies," costs of drilling exploratory wells are initially capitalized and later charged to expense if upon determination the wells do not justify commercial development. Occasionally, an exploratory well may be determined to have found oil and gas reserves, but classification of those reserves as proved cannot be made when drilling is completed. If classification of proved reserves cannot be made in an area requiring a major capital expenditure, the cost of drilling the exploratory well is carried as an asset provided that (a) there have been sufficient reserves found to justify completion as a producing well if the required capital expenditure is made and (b) further well completion work needs to be performed or additional exploratory wells need to be drilled and those activities are either underway or firmly planned for the near future. If either of these two criteria is not met, exploratory well costs are expensed. For all other exploratory wells, costs of exploratory wells are expensed if the reserves cannot be classified as proved after one year following the completion of drilling. As of December 31, 2004, we had capitalized $3.1 million of exploratory drilling costs related to three exploratory wells which spud in 2004 and which had completed drilling but were under evaluation for commercial viability as of December 31, 2004. One of the wells is currently being evaluated under an extended production test to evaluate whether additional completion expenditures are warranted, and two of the wells are dependent on the results of additional drilling nearby which is currently underway.

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

	Year ended December 31,			
	2004		2003	
	# Wells	Cost (in thousands)	# Wells	Cost (in thousands)
Balance at beginning of period	10	$ 3,785	—	$ —
Additions pending determination of proved reserves	3	3,654	10	3,785
Reclassifications to wells, equipment and facilities based on the determination of proved reserves	—	—	—	—
Charged to expense	(10)	(4,360)	—	—
Balance at end of period	3	$ 3,079	10	$3,785

There were no exploratory wells under evaluation at December 31, 2002. We had no capitalized exploratory drilling costs that had been under evaluation for a period greater than one year as of December 31, 2004 or 2003.

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. Interest costs associated with non-producing leases were capitalized in the amounts of $2.0 million, $2.0 million, and $1.0 million in 2004, 2003 and 2002, respectively. Unproved leasehold costs are assessed periodically, on a property-by-property basis, and a loss is recognized to the extent, if any, the cost of the property has been impaired. As unproved leaseholds are determined to be productive, the related costs are transferred to proved leaseholds and amortized on a unit-of-production basis. As of December 31, 2004 and 2003, unproved leasehold costs amounted to $61.0 million and $60.0 million, respectively.

Asset Retirement Obligation

In accordance with SFAS No. 143, "Accounting for 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. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. See Note 12, "Asset Retirement Obligation." In general, the amount of an ARO and the costs capitalized will be equal to 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 an assumed cost of funds for our Company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds, and the additional capitalized costs will be depreciated on a unit-of-production basis over the productive life of the related properties. Both the accretion and the depreciation are included in depreciation, depletion and amortization on our consolidated statements of income.

Other Property and Equipment

Other property and equipment primarily represent PVR's ownership in coal fee mineral interests. Other 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 expensed as incurred. Depreciation and amortization of property and equipment is generally computed using the straight-line or declining balance methods over the estimated useful lives of such property and equipment, ranging from three years to 20 years. Coal properties are depleted on an area-by-area basis at a rate based upon the cost of the mineral properties and estimated proven and probable tonnage therein. When an asset is retired or sold, its cost and related accumulated depreciation and amortization are removed from the accounts. The difference between net book value (net of any related asset retirement obligation) and proceeds from disposition is recorded as a gain or loss.

Impairment of Long-Lived Assets

We review our long-lived assets to be held and used, including proved oil and gas properties and the Partnership's coal properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss must be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we would recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the present value of future net cash flows from proved reserves, discounted utilizing a rate commensurate with the risk and remaining lives for the respective oil and gas properties.

Equity Investments

We use the equity method of accounting to account for the Partnership's investment in a coal handling joint venture, recording the initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect the Partnership's share of income of the investee and is reduced to reflect the Partnership's share of losses of the investee or distributions received from the investee as the joint venture reports them. The Partnership's share of earnings or losses from the investment is included in other revenues on the consolidated statements of income.

Concentration of Credit Risk

Approximately 78 percent of consolidated accounts receivable at December 31, 2004, resulted from oil and gas sales and joint interest billings to third party companies in the oil and gas industry. This concentration of customers and joint interest owners may impact our overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral from a customer or joint interest owner, we analyze the entity's net worth, cash flows, earnings and credit ratings. Receivables are generally not collateralized. Historical credit losses incurred on receivables have not been significant.

The remaining 22 percent of consolidated accounts receivable at December 31, 2004, resulted from accrued revenues from the Partnership's lessee production. This concentration of lessees may impact the Partnership's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral from a lessee, the Partnership analyzes the entity's net worth, cash flows, earnings and credit ratings to the extent information is available. Receivables are generally not collateralized. Historical credit losses incurred by the Partnership on receivables have not been significant.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, a note receivable, accounts payable, derivative instruments and long-term debt. The carrying values of all of these financial instruments, except for PVR's fixed rate long-term debt, approximate fair value. The fair value of PVR senior unsecured debt at December 31, 2004 and 2003, was $86.2 million and $88.9 million, respectively.

Revenues

Oil and Gas. Revenues associated with sales of crude oil, condensate, natural gas, and natural gas liquids are recorded when title passes to the customer. Natural gas sales revenues from properties in which we have an interest with other producers are recognized on the basis of our net working interest ("entitlement" method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. Any amount received in excess of our share is treated as deferred revenues. If we take less than we are entitled to take, the under-delivery is recorded as a receivable.

Coal Royalties. Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenues from those sales. Most of the Partnership's coal leases are based on minimum monthly or annual rental payments, a minimum dollar royalty per ton and/or a percentage of the gross sales price. The remainder of PVR's coal royalty revenues was derived from fixed royalty rate leases, which escalate annually, with pre-established minimum monthly payments. Coal royalty revenues are accrued on a monthly basis, based on PVR's best estimates of coal mined on its properties.

Coal Services. Coal services revenues are recognized when lessees use the Partnership's facilities for the processing, loading and/or transportation of coal. Coal services revenues consist of fees collected from the Partnership's lessees for the use of the Partnership's loadout facility, coal preparation plants and dock loading facility.

Timber. Timber revenues are recognized when timber is sold in a competitive bid process involving sales of standing timber on individual parcels and, from time to time, on a contract basis where independent contractors harvest and sell the timber. Timber revenues are recognized when the timber parcel has been sold or when the timber is harvested by the independent contractors. Title and risk of loss pass to the independent contractors upon the execution of the contract. In addition, if the contractors do not harvest the timber within the specified time period, the title of the timber reverts back to the Partnership with no refund of original payment.

Minimum Rentals. Most of the Partnership's lessees are required to make minimum monthly or annual payments that are generally recoupable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recoups a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalty revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods, the deferred income attributable to the minimum payment is recognized as minimum rental revenues and is included in other revenues.

Equity Earnings. The Partnership recognizes its share of income or losses from its investment in a coal handling joint venture as the joint venture reports them to the Partnership. Equity earnings are included in other revenues.

Hedging Activities

From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas and crude oil price volatility. The derivative financial instruments, which are placed with major financial institutions that we believe are minimum credit risks, take the form of costless collars and swaps. All derivative financial instruments are recognized in the financial statements at fair value in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149 and related interpretations.

All derivative instruments are recorded on the balance sheet at fair value. See Note 10, "Hedging Activities." If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we utilize only cash flow hedges, and the remaining discussion relates exclusively to this type of derivative instrument. All hedge transactions are subject to our risk management policy, which has been reviewed and approved by our Board of Directors.

We formally document all relationships between hedging instruments and hedged items, as well as the risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. We measure hedge effectiveness on a period basis. When it is determined that a derivative is not highly effective as a hedge, or that it has ceased to be highly effective, we discontinue hedge accounting prospectively.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in earnings prospectively.

Gains and losses on hedging instruments when settled are included in natural gas or crude oil production revenues in the period that the related production is delivered.

The fair values of our hedging instruments are determined based on third party forward price quotes for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices.

Income Tax

We account for income taxes in accordance with the provisions of SFAS No. 109, "Accounting for Income Taxes." This Statement requires a company to recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in a 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.

Stock-Based Compensation

We have stock compensation plans that allow, among other grants, incentive and nonqualified stock options to be granted to key employees and officers and nonqualified stock options to be granted to directors. See Note 18, "Stock Compensation and Stock Ownership Plans." We account for those plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share as if we had applied the fair value recognition provision of SFAS No. 123, "Accounting for Stock-Based Compensation," to stock-based employee options (in thousands, except per share data).

	Year ended December 31,		
	2004	2003	2002
Net income, as reported	$33,355	$28,522	$12,104
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	435	332	424
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(1,022)	(1,119)	(1,268)
Pro forma net income	$32,768	$27,735	$11,260
Earnings per share			
Basic—as reported	$ 1.82	$ 1.59	$ 0.68
Basic—pro forma	$ 1.79	$ 1.55	$ 0.63
Diluted—as reported	$ 1.81	$ 1.58	$ 0.67
Diluted—pro forma	$ 1.77	$ 1.53	$ 0.63

New Accounting Standards

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," under which the Partnership classified leased coal mineral rights as intangible assets. In April 2004, the FASB issued a FASB Staff Position ("FSP") that amends certain sections of SFAS No. 141 and No. 142 relating to the characterization of coal mineral rights. As allowed by the FSP, the Partnership early adopted the FSP in April 2004 and, accordingly, reclassified its leased coal mineral rights back to tangible property. The Partnership discontinued straight-line amortization upon adoption and will deplete its coal mineral rights using the units-of-production method on a prospective basis. The amount capitalized related to a mineral right represents its fair value at the time such right was acquired, less accumulated amortization. Pursuant to the FSP, for comparative presentation purposes, $4.9 million was reclassified from a separate line item in other noncurrent assets to net property and equipment as of December 31, 2003, on the accompanying consolidated balance sheet.

In September 2004, the FASB issued another FSP to clarify that the scope exception in paragraph 8(b) of SFAS No. 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing companies. The FSP affirmed our historical practice of including the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties under SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies."

The FASB issued FSP SFAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," in May 2004, effective for the first interim or annual period beginning after June 15, 2004. The FSP requires employers that qualify for a prescription-drug subsidy under Medicare legislation enacted in December 2003 to recognize the reduction in costs as employees provide services in future years. We adopted FSP SFAS 106-2 on July 1, 2004, and it did not have a significant impact on our financial statements. As a result of the Medicare Prescription Drug, Improvement and Modernization Act of 2003, our accumulated postretirement benefit obligation as of January 1, 2004, decreased by $0.4 million.

The Emerging Issues Task Force ("EITF") issued EITF 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations," in November 2004. EITF 03-13 is effective for a component of an enterprise that is either disposed of or classified as held for sale in fiscal periods beginning after December 15, 2004. The consensus gives interpretive guidance on the criteria for discontinued operations.

In December 2004, the FASB issued a revised version of SFAS No. 123, "Share-Based Payment," which requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. SFAS No. 123 will be effective for the first interim or annual period beginning after June 15, 2005. At that time, we will be required to begin recognizing compensation expense for the unvested portion of outstanding options. We are currently assessing the effect of the revised SFAS No. 123 on our financial statements.

SFAS No. 153, "Exchanges of Productive Assets," was also issued in December 2004 and requires that nonmonetary exchanges of assets be accounted for at fair value, recognizing any gain or loss, subject to certain criteria. Before this new rule, companies were permitted to account for nonmonetary exchanges at book value. SFAS No. 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. This new pronouncement is not expected to have a material effect on our financial statements.

4. Acquisitions

Oil and Gas

On January 22, 2003, we acquired a 25 percent non-operating working interest in properties located in a producing field in south Texas ("the south Texas acquisition"). The properties were acquired in a cash transaction with a private investor group for $33.5 million. The acquisition, which was effective December 31, 2002, was financed with the Company's existing credit facility. Nine producing wells were acquired at the time of the acquisition. Ten successful development wells and one development dry hole have been drilled in the field since the acquisition date.

Coal Royalty and Land Management

In November 2004, the Partnership entered into an agreement to purchase from Cantera Natural Gas LLC ("Cantera") a natural gas gathering and processing business with assets in Oklahoma and Texas for $191 million of cash (the "Cantera Acquisition"). The Cantera Acquisition closed on March 3, 2005, as described in Note 23, "Subsequent Events." As of December 31, 2004, PVR had capitalized $0.7 million for costs related to the Cantera Acquisition.

In July 2004, the Partnership acquired from affiliates of Massey Energy Company a 50 percent interest in a joint venture formed to own and operate end-user coal handling facilities. The purchase price was $28.4 million and was funded through the Partnership's credit facility. The joint venture owns coal handling facilities which unload coal shipments and store and transfer coal for three industrial coal consumers in the chemical, paper and lime production industries located in Tennessee, Virginia and Kentucky, respectively. A combination of fixed monthly fees and per ton throughput fees is paid by those consumers under long-term leases expiring between 2007 and 2019. The Partnership recognized equity earnings of $0.4 million related to its ownership in the joint venture beginning in July 2004 and received distributions from the joint venture of approximately $1.0 million during 2004.

In January 2004, the Partnership completed the construction of a new coal loadout facility for one of its lessees on its Coal River property in West Virginia. The $4.4 million loadout facility is designed for the high-speed loading of 150-car unit trains and became operational on February 1, 2004, contributing $0.5 million to 2004 coal services revenues.

In December 2002, the Partnership acquired two properties containing approximately 120 million tons of coal reserves (unaudited) from affiliates of Peabody Energy Corporation ("Peabody") for 1,522,325 million common units, 1,240,833 million Class B common units (a combined common unit value of $57.0 million) and $72.5 million in cash plus closing costs (the "Peabody Acquisition"). Approximately $6.1 million, or 293,700 of the Class B common units were held in escrow at closing pending certain title transfers. In July 2003, 241,000 Class B common units were released from escrow in exchange for certain title transfers in New Mexico. In July 2003, all of the class B common units were converted to common units, in accordance with their terms, upon the approval of the Partnership's common unitholders. As of December 31, 2003, 52,700 common units remained in escrow pending Peabody acquiring and transferring to PVR certain of the West Virginia reserves it purchased. As a result of the units held in escrow, approximately one million tons of coal reserves and 52,700 common units were not included in property, plant and equipment or partners' capital, respectively, at December 31, 2003. In February 2004, PVR released from escrow 51,393 common units in exchange for certain title transfers in West Virginia. As of December 31, 2004, 1,307 units were being held in escrow pending Peabody's acquiring and transferring to PVR certain of the West Virginia reserves it purchased. As a result of the units held in escrow at December 31, 2004, 1,307 common units were not included in partners' capital at that date. These 1,307 common units were released from escrow in January 2005. All of the coal reserves we purchased from Peabody are being leased back to Peabody for fixed royalty rates which escalate annually over the life of production. As part of the Peabody Acquisition, Peabody received the right to share in the general partner's incentive distribution rights, if any, in exchange for additional properties Peabody may source to the Partnership in the future. The acquired coal reserves had existing productive operations that have been included in the Partnership's statements of income since the closing date of the Peabody Acquisition.

In November 2002, the Partnership completed the acquisition of certain infrastructure-related equipment and other assets integral to mining on one of its West Virginia properties. The purchased assets included a 900-ton per hour coal preparation plant, a unit-train loading facility and a railroad-granted rebate on coal loaded through the facility. The Partnership acquired the assets from an independent private entity and its lessors for $5.1 million in cash, which was funded with the proceeds from the sale of U.S. Treasury notes, plus the assumption of approximately $2.4 million in reclamation liabilities and approximately $0.6 million of stream mitigation obligations. These assets did not have existing productive operations at the time of acquisition. In 2003, the Partnership leased the property and related infrastructure to a third party who is actively mining coal reserves on the property. Consequently, all of the reclamation and stream mitigation liabilities were assigned to the new lessee.

In August 2002, the Partnership acquired approximately 16 million tons of coal reserves located in West Virginia for $12.3 million. The acquisition, which was purchased from an independent private entity, was funded with the proceeds from the sale of U.S. Treasury notes. The acquired reserves had existing productive operations that have been included in the Partnership's statements of income as of the closing date of the acquisition.

The factors used by the Partnership to determine the fair market value of acquisitions include, but are not limited to, discounted future net cash flows on a risked-adjusted basis, geographic location, quality of resources, potential marketability and financial condition of the lessees.

5. Stock Split and Change in Par Value

On May 4, 2004, the Board of Directors approved a two-for-one split of the Company's common stock in the form of a 100 percent stock dividend payable on June 10, 2004, to shareholders of record on June 3, 2004. Shareholders received one additional share of common stock for each share held on the record date. All common shares and per share data have been retroactively adjusted to reflect the stock split. Also effective June 10, 2004, the Company changed the par value of its common stock from $6.25 to $0.01 per share.

6. Assets Held for Sale

In October 2004, the Board of Directors approved a plan to sell certain oil and gas properties in Texas. In accordance with SFAS No. 144, "Accounting for the Impairment of Disposal or Long-Lived Assets," the carrying value of these oil and gas properties was written down to fair market value less costs to sell and was reclassified to assets held for sale on the consolidated balance sheet. We recognized a loss of $7.5 million upon reclassification of the properties to assets held for sale.

In December 2004, we entered into an agreement to sell these Texas oil and gas properties for cash proceeds of $9.7 million, which approximates the carrying value of assets held for sale at December 31, 2004. The sale closed in January 2005, as described in Note 24, "Subsequent Event."

7. Property and Equipment

Property and equipment includes (in thousands):

	December 31, 2004	December 31, 2003
Oil and gas properties		
Proved	$530,087	$443,248
Unproved	61,013	60,042
Total oil and gas properties	591,100	503,290
Other property and equipment:		
Coal mineral interest	251,244	249,950
Other equipment	20,962	20,518
Land and timber	1,985	1,979
Total property and equipment	865,291	775,737
Less: Accumulated depreciation, depletion and amortization	199,803	149,934
Net property and equipment	$665,488	$625,803

8. Impairment of Oil and Gas Properties

In accordance with SFAS No. 144, we review oil and gas properties for impairment 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 commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When we find that the carrying amounts of the properties exceed their estimated undiscounted future cash flows, we adjust the carrying amounts of the properties to their fair value as determined by discounting their estimated future cash flows. The factors used to determine fair value included, but were not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

For the year ended December 31, 2004, we recognized a pretax charge of $0.7 million related to the impairment of certain West Virginia horizontal coalbed methane ("CBM") properties. This impairment was associated with a CBM well completed in 2004 in northern West Virginia that had insufficient natural gas reserves to support the historical cost basis of the property.

For the year ended December 31, 2003, we recognized a pretax charge of $0.4 million related to the impairment of certain south Texas properties. These impairments were a result of downward reserve revisions on these properties caused by the poor performance of these wells near the end of their productive lives.

Due to downward reserve revisions in 2002, we recognized a pretax charge of $0.8 million related to the impairment of oil and gas properties for the year ended December 31, 2002.

9. Equity Investments

As described in Note 4, "Acquisitions," the Partnership acquired a 50 percent interest in Coal Handling Solutions, LLC, a joint venture formed to own and operate end-user coal handling facilities. The Partnership accounts for the investment under the equity method of accounting. In 2004, the original cash investment of

$28.4 million was capitalized. At December 31, 2004, the Partnership's equity investment totaled $27.9 million, which exceeded its portion of the underlying equity in net assets by $12.7 million. The difference is being amortized to equity earnings over the life of coal services contracts in place at the time of the acquisition. In accordance with the equity method, the Partnership recognized equity earnings of $0.4 million in 2004 with a corresponding increase in the investment. Cash distributions of approximately $1.0 million received from the joint venture in 2004 were recorded as a reduction of the investment. The investment is included in other assets on the consolidated balance sheet. Equity earnings are included in other revenues on the consolidated income statement.

10. Hedging Activities

Commodity Cash Flow Hedges

The following table sets forth our hedge positions as of December 31, 2004:

	Average Volume Per Day	Weighted Average Price			Estimated Fair Value
		Swaps	Collars		
			Floor	Ceiling	
	(in MMbtus)		(per MMbtu)		(in thousands)
Natural gas hedging positions					
First Quarter 2005					
Costless Collars	28,656		4.94	7.20	$(164)
Swaps (January only)	1,100	4.70			(52)
Second Quarter 2005					
Costless Collars	25,330		5.19	7.15	(13)
Third Quarter 2005					
Costless Collars	25,000		5.32	7.21	(126)
Fourth Quarter 2005					
Costless Collars	24,000		5.50	8.51	119
First Quarter 2006					
Costless Collars	15,689		5.32	9.38	(176)
Second Quarter 2006					
Costless Collars	11,648		5.14	10.04	300
	(in Bbls)	(per Bbl)			
Crude oil hedging positions					
First Quarter 2005					
Swaps (January only)	400	30.13			(354)
Total					$(466)

Based upon our assessment of our derivative contracts designated as cash flow hedges at December 31, 2004, we reported (i) a net hedging liability of approximately $0.5 million and (ii) a loss in accumulated other comprehensive income of $0.3 million, net of a related income tax benefit of $0.2 million. In connection with monthly settlements, we recognized net hedging losses in natural gas and oil revenues of $5.9 million for the year ended December 31, 2004. Based upon future oil and natural gas prices as of December 31, 2004, $0.6 million of hedging losses are expected to be realized within the next 12 months. The amounts we ultimately realize will vary due to changes in the fair value of the open derivative contracts prior to settlement. We recognized net hedging losses of $6.1 million and $1.1 million for the years ended December 31, 2003 and 2002, respectively.

Interest Rate Swap

In March 2003, PVR entered into an interest rate swap agreement with an original notional amount of $30 million to hedge a portion of the fair value of its 5.77 percent senior unsecured notes which mature over a ten-year period. The notional amount decreases by one-third of each principal payment. Under the terms of the interest rate swap agreement, the counterparty pays PVR a fixed annual rate of 5.77 percent on the notional amount and receives a variable rate equal to the floating interest rate which will be determined semi-annually and will be based on the six-month London Interbank Offering Rate plus 2.36 percent. See Note 14, "Long-Term Debt" for a description of the underlying debt instrument to which the interest rate swap applies. Settlements on the swap are recorded as interest expense. At December 31, 2004, the notional amount was $29.5 million. The swap is designated as a fair value hedge because it has been determined that it is highly effective, and it has been reflected as a decrease in long-term debt of approximately $0.8 million and $0.7 million as of December 31, 2004 and 2003, respectively, with a corresponding increase in long-term hedging liabilities.

11. Accrued Liabilities

Accrued liabilities are summarized as follows (in thousands):

	December 31,	
	2004	2003
Drilling costs	$ 7,516	$ 4,877
Royalties	6,618	3,277
Production and franchise taxes	4,422	2,850
Compensation	3,111	2,659
Deferred income	1,207	1,610
Interest	1,600	1,477
Professional services	646	659
Pension and post-retirement healthcare	300	300
Other	933	1,444
Total	$26,353	$19,153

12. Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of such assets.

The fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is also added to the carrying amount of the associated asset and is depreciated over the life of the asset. The liability is accreted through a charge to accretion expense, which is recorded as additional depreciation, depletion and amortization. If the obligation is settled for other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

We identified all required asset retirement obligations and determined the fair value of these obligations on the date of adoption. The determination of fair value was based upon regional market and specific well or mine type information. In conjunction with the initial application of SFAS No. 143, we recorded a cumulative effect of change in accounting principle, net of taxes, of approximately $1.4 million as an increase to income in 2003. Below is a reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligations, which are included in other liabilities, or accrued liabilities for the current portion, on the consolidated balance sheets.

	Year ended December 31, 2004	2003
	(in thousands)	
Balance at beginning of period	$3,389	$ —
Liability recorded upon initial adoption	—	2,685
Liabilities incurred	319	666
Liabilities settled	(274)	(120)
Accretion expense	322	158
	3,756	3,389
Less: Current portion	121	—
Balance at end of period	$3,635	$3,389

13. Other Liabilities

Other liabilities are summarized in the following table (in thousands):

	December 31, 2004	2003
Deferred income	$ 8,726	$ 6,028
Asset retirement obligation	3,635	3,389
Pension	2,205	2,242
Post-retirement health care	2,075	2,102
Reclamation environmental liabilities	1,306	1,413
Other	148	14
Total	$18,095	$15,188

14. Long-Term Debt

Long-term debt as of December 31, 2004 and 2003, consisted of the following (in thousands):

	December 31, 2004	2003
Penn Virginia revolving credit facility, variable rate of 3.9 percent at December 31, 2004, due in 2007	$ 76,000	$ 64,000
PVR revolving credit facility, variable rate of 4.1 percent at December 31, 2004, due in 2006	30,000	2,500
PVR senior unsecured notes*	87,726	89,286
	193,726	155,786
Less: Current maturities	(4,800)	(1,500)
Total long-term debt	$188,926	$154,286

* Includes negative fair value adjustments of $0.8 million and $0.7 million as of December 31, 2004 and 2003, respectively, related to interest rate swap designated as a fair value hedge. See Note 10, "Hedging Activities."

Penn Virginia Revolving Credit Facility

In December 2003, we entered into a revolving credit facility (the "Revolver") with a group of major banks led by JP Morgan Chase Bank N.A., which has a borrowing base of $200 million and a $150 million initial commitment, and expires in December 2007. The Revolver is secured by a portion of our proved oil and gas reserves.

The Revolver is governed by a borrowing base calculation and is redetermined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.25 to 2.00 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin ranging from 0.30 to 0.50 percent. The weighted average interest rate on borrowings incurred during the year ended December 31, 2004, was approximately 2.86 percent. We pay commitment fees on the unused portion of the Revolver. The Revolver allows for issuance of letters of credit that are limited to no more than $20 million. At December 31, 2004, letters of credit issued were $0.3 million. The financial covenants require us to maintain levels of debt-to-earnings and dividend limitation restrictions. We are currently in compliance with all of our covenants.

PVR Revolving Credit Facility

As of December 31, 2004, the Partnership had a $100 million unsecured revolving credit facility (the "PVR Revolver") that expires in October 2006. The PVR Revolver was with a syndicate of financial institutions led by PNC Bank, National Association ("PNC") as its agent. The PVR Revolver was available for general partnership purposes, including working capital, capital expenditures and acquisitions, and included a $5 million sublimit that was available for working capital needs and distributions and a $5 million sublimit for the issuance of letters of credit. PVR had utilized letters of credit of $1.6 million as of December 31, 2004 and 2003.

At the Partnership's option, indebtedness under the PVR Revolver bore interest at either (i) the Eurodollar rate plus an applicable margin which ranged from 1.25 percent to 2.25 percent based on the ratio of consolidated indebtedness to consolidated EBITDA (as defined by the credit agreement) for the four most recently completed fiscal quarters, or (ii) the higher of the federal funds rate plus 0.50 percent or the prime rate as announced by PNC. The Partnership paid commitment fees on the unused portion of the PVR Revolver. The financial covenants of the PVR Revolver required PVR to maintain levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted PVR's borrowing capacity under the PVR Revolver to approximately $38.6 million as of December 31, 2004. As of December 31, 2004, the Partnership was in compliance with all of its covenants.

Concurrent with the closing of the Cantera Acquisition, PVR entered into a new credit facility which was used to fund the Cantera Acquisition and to repay borrowings under the PVR Revolver (see Note 23, "Subsequent Events").

In connection with PVR's Cantera Acquisition, during the fourth quarter of 2004, the Partnership entered into a bridge loan commitment with two financial institutions. The bridge loan was terminated late in the fourth quarter of 2004, and PVR replaced it with an expanded credit facility as described in Note 23, "Subsequent Events." In the fourth quarter of 2004, PVR paid loan issue costs of approximately $1.2 million related to the bridge loan commitment, which were recorded as interest expense during the fourth quarter of 2004.

PVR Senior Unsecured Notes

In March 2003, the Partnership closed a private placement of $90 million of senior unsecured notes (the "PVR Notes"). The PVR Notes bear interest at a fixed rate of 5.77 percent and mature over a ten-year period ending in March 2013, with semi-annual interest payments. The PVR Notes contain various covenants similar to those contained in the PVR Revolver. As of December 31, 2004, the Partnership was in compliance with all of the covenants.

Line of Credit

We have a $5 million line of credit with a financial institution effective through June 2005, renewable annually. We have an option to elect either a fixed rate LIBOR loan, floating rate LIBOR loan or base rate (as determined by the financial institution) loan. At December 31, 2004 and 2003, we had no outstanding borrowings against the line of credit.

Debt Maturities

Aggregate maturities of the principal amounts of long-term debt for the next five years and thereafter are as follows (in thousands):

2005	$ 4,800
2006	38,300
2007	87,000
2008	12,700
2009	14,100
Thereafter	37,600
	$194,500
Less: Interest rate swap	(774)
Total debt, including current maturities	$193,726

15. Income Taxes

The provision for income taxes from continuing operations is comprised of the following (in thousands):

	Year ended December 31,		
	2004	2003	2002
Current income taxes			
Federal	$ 2,619	$ 2,067	$ (320)
State	3	1,007	(878)
Total current	2,622	3,074	(1,198)
Deferred income taxes			
Federal	15,247	12,090	5,236
State	3,978	3,202	2,897
Total deferred	19,225	15,292	8,133
Total income tax expense	$21,847	$18,366	$ 6,935

The difference between the taxes computed by applying the statutory tax rate to income from operations before income taxes and our reported income tax expense is as follows (in thousands):

	Year ended December 31,					
	2004		2003		2002	
Computed at federal statutory tax rate	$19,320	35.0%	$15,933	35.0%	$6,586	35.0 %
State income taxes, net of federal income tax benefit	2,486	4.5%	2,611	5.7%	1,312	7.0 %
Non-conventional fuel source credit	—	—	—	—	(926)	(4.9)%
Other, net	41	0.1%	(178)	(0.4)%	(37)	(0.2)%
Total income tax expense	$21,847	39.6%	$18,366	40.3%	$6,935	36.9 %

The principal components of our net deferred income tax liability are as follows (in thousands):

	December 31,	
	2004	2003
Deferred tax liabilities:		
Notes receivable	$ —	$ 428
Oil and gas properties	97,267	81,927
Other	8,890	1,553
Total deferred tax liabilities	106,157	83,908
Deferred tax assets:		
Pension and post-retirement benefits	1,603	1,626
Deferred income—coal properties	3,112	564
Net operating loss carryforwards	1,810	2,057
Other	1,720	1,798
Total deferred tax assets	8,245	6,045
Net deferred tax liability	$ 97,912	$77,863

As of December 31, 2004, we have various net operating loss carryforwards ("NOLs") for state tax purposes of approximately $27.3 million which, if unused, will expire from 2017 to 2023. Realization of deferred tax assets associated with the NOLs is dependent upon generating sufficient taxable income prior to their expiration. Although realization is not assured, we believe it is more likely than not that the deferred tax assets will be realized through future taxable earnings. However, the net deferred tax assets could be reduced further if our estimate of taxable income in future periods is significantly reduced.

16. Employee Benefit Plans

401(k) Plan

We sponsor a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 50 percent of their base salaries. After the employee meets certain service requirements, we match each employee's contributions up to six percent of the employee's base salary. Our matching contributions to the 401(k) Plan were approximately $0.4 million, $0.3 million and $0.2 million for the years ended December 31, 2004, 2003, and 2002, respectively. Beginning in 2005, the Company may make additional contributions at its discretion.

Pension Plans and Other Post-retirement Benefits

We provide post-separation ("pension") payments to certain eligible employees. Benefits are typically based on the employee's average annual compensation and service.

We also offer post-retirement healthcare benefits to employees hired prior to January 1, 1991, who retire from active service. The benefits include medical and prescription drug coverage for the retirees and dependents and life insurance for the retirees. The medical coverage is noncontributory for retirees who retired prior to January 1, 1991, and may be contributory for retirees who retired after December 31, 1990.

We use a December 31 measurement date for these plans.

In July 2004, we adopted Financial Accounting Standards Board ("FASB") Staff Position ("FSP") SFAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." The FSP requires employers that qualify for a prescription-drug subsidy under Medicare legislation enacted in December 2003 to recognize the reduction in costs as employees provide services in future years. FSP SFAS 106-2 did not have a significant impact on our financial statements. As a result of the Medicare Prescription Drug, Improvement and Modernization Act of 2003, our accumulated postretirement benefit obligation as of January 1, 2004, decreased by $0.4 million.

A reconciliation of the changes in the benefit obligations and fair value of assets for the years ended December 31, 2004 and 2003, and a statement of the funded status at December 31, 2004 and 2003, is as follows (in thousands):

	Pension		Post-retirement Healthcare	
	2004	2003	2004	2003
Reconciliation of benefit obligation:				
Obligation—beginning of year	$ 2,382	$ 2,377	$ 4,490	$ 4,960
Service cost	—	—	28	24
Interest cost *	141	153	261	285
Benefits paid	(265)	(253)	(478)	(490)
Actuarial (gain) loss **	90	105	103	(289)
Obligation—end of year	2,348	2,382	4,404	4,490
Reconciliation of fair value of plan assets:				
Fair value—beginning of year	—	—	—	—
Employer contributions	265	253	455	474
Participant contributions	—	—	23	16
Benefit payments	(265)	(253)	(478)	(490)
Fair value—end of year	—	—	—	—
Funded status:				
Funded status—end of year	(2,348)	(2,382)	(4,404)	(4,490)
Unrecognized transition obligation	10	13	—	—
Unrecognized prior service cost	24	30	935	1,024
Unrecognized (gain) loss	642	577	1,237	1,208
Net amount recognized	$(1,672)	$(1,762)	$(2,232)	$(2,258)

* Interest cost for the post-retirement healthcare plan in 2004 includes a $25 thousand reduction resulting from the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act").

** Actuarial (gain) loss for the post-retirement healthcare plan in 2004 includes a $28 thousand reduction resulting from the Medicare Act.

Since the benefit obligation exceeds the fair value of plan assets, we have recognized a liability in the statements of financial position. The following table provides the components of the benefit obligation recognized in the statements of financial position at December 31, 2004 and 2003 (in thousands):

	Pension		Post-retirement Healthcare	
	2004	2003	2004	2003
Accrued benefit liability	$(2,348)	$(2,382)	$(2,232)	$(2,258)
Other long-term assets	34	43	—	—
Accumulated other comprehensive income	642	577	—	—
Obligation—end of year	$(1,672)	$(1,762)	$(2,232)	$(2,258)

The following table provides the components of net periodic benefit cost for the plans for the years ended December 31, 2004 and 2003 (in thousands):

	Pension		Post-retirement Healthcare	
	2004	2003	2004	2003
Service cost	$—	$—	$ 28	$ 24
Interest cost	141	153	261	285
Amortization of prior service cost	6	6	88	88
Amortization of transitional obligation	3	3	—	—
Recognized actuarial (gain) loss	25	19	52	45
Net periodic benefit cost	$ 175	$ 181	$429	$442

The assumptions used in the measurement of our benefit obligation were as follows:

	Pension		Post-retirement Healthcare	
	2004	2003	2004	2003
Discount rate	5.75%	6.25%	5.75%	6.25%

For measurement purposes, an 11.5 percent annual rate increase in the per capita cost of covered health care benefits was assumed for 2004. The rate is assumed to decrease gradually to five percent for 2013 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for post-retirement benefits. A one percent change in assumed health care cost trend rates would have the following effects for 2004 (in thousands):

	One Percent Increase	One Percent Decrease
Effect on total of service and interest cost components	$ 14	$ (13)
Effect on post-retirement benefit obligation	207	(197)

We expect to contribute $0.2 million to the pension plan and $0.5 million to the post-retirement healthcare plan in 2005.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension	Post-retirement Healthcare *
	(in thousands)	
2005	$225	$ 461
2006	224	406
2007	221	407
2008	218	410
2009	209	406
2010 – 2014	843	1,887

* Expected payments for post-retirement healthcare benefits have been reduced by $57 thousand in 2006, $57 thousand in 2007, $55 thousand in 2008, $53 thousand in 2009, and $219 thousand for 2010 through 2014 for subsidy receipts expected to be received as a result of the Medicare Act. No subsidy is expected in 2005.

17. Discontinued Operations

During 2002, we sold certain oil and gas properties, which included various interests in south Texas properties acquired in 2001. The net carrying amount of properties sold was approximately $0.5 million. Accordingly, under the provisions of SFAS No. 144 the components of discontinued operations were as follows for the year ended December 31, 2002 (in thousands):

Production	
Oil and condensate (Mbbls)	16
Natural gas (MMcf)	18
Total production (MMcfe)	114
Revenues	
Natural gas	$ 48
Oil and condensate	332
Total revenues	380
Expenses	
Operating expenses	352
Depreciation, depletion and amortization	25
Total expenses	377
Income from discontinued operations	3
Gain on sale of properties	337
	340
Income taxes	(119)
Net income from discontinued operations	$ 221

18. Earnings Per Share

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share ("EPS") for the last three years (in thousands, except per share data).

	2004	2003	2002
Income from continuing operations	$33,355	$27,159	$11,883
Income from discontinued operations	—	—	221
Cumulative effect of change in accounting principle	—	1,363	—
Net income	$33,355	$28,522	$12,104
Weighted average shares, basic	18,306	17,976	17,860
Effect of dilutive securities:			
Stock options	161	136	88
Weighted average shares, diluted	18,467	18,112	17,948
Income from continuing operations per share, basic	$ 1.82	$ 1.51	$ 0.67
Income from discontinued operations per share, basic	—	—	0.01
Cumulative effect of change in accounting principle, basic	—	0.08	—
Net income per share, basic	$ 1.82	$ 1.59	$ 0.68
Income from continuing operations per share, diluted	$ 1.81	$ 1.50	$ 0.66
Income from discontinued operations per share, diluted	—	—	0.01
Cumulative effect of change in accounting principle, diluted	—	0.08	—
Net income per share, diluted	$ 1.81	$ 1.58	$ 0.67

Not included in calculation of the denominator for diluted earnings per share for the years ended December 31, 2003 and 2002, were options with an exercise price that exceeded the average price of the underlying securities, and as such these options are not considered to be dilutive. All options outstanding at December 31, 2004, had exercise prices exceeding the average price of the underlying securities.

19. Stock Compensation and Stock Ownership Plans

Stock Compensation Plans

We have several stock compensation plans (collectively known as the "Stock Compensation Plans") that allow, among other grants, incentive and nonqualified stock options to be granted to key employees and officers and nonqualified stock options to be granted to directors. Options granted prior to 2004 under the Stock Compensation Plans may be exercised at any time after one year and prior to 10 years following the grant, subject to special rules that apply in the event of death, retirement and/or termination of the employment of an optionee. Options granted in 2004 vest ratably over a three-year period so that one-third is exercisable after one year, another third is exercisable after two years, and the remaining third is exercisable after three years. The exercise price of all options granted under the Stock Compensation Plans is at the fair market value of the Company's stock on the date of the grant. At December 31, 2004, there were approximately 228,000 and 525,000 shares available for issuance to directors and employees, respectively, pursuant to the Stock Compensation Plans.

The following table summarizes information with respect to the common stock options awarded under the Stock Option Plans and grants described above.

	2004		2003		2002	
	Shares Under Options	Weighted Avg Exercise Price	Shares Under Options	Weighted Avg Exercise Price	Shares Under Options	Weighted Avg Exercise Price
Outstanding at beginning of year	801,900	$16.46	807,700	$14.70	718,900	$12.99
Granted	210,000	$28.52	206,000	$18.71	226,800	$18.46
Exercised	364,400	$14.43	209,800	$11.85	114,000	$12.23
Cancelled / forfeited	11,600	$28.09	2,000	$18.30	24,000	$10.69
Outstanding at end of year	635,900	$21.10	801,900	$16.46	807,700	$14.70
Exercisable at end of year	436,300	$17.71	597,900	$15.69	580,900	$13.23
Weighted average of fair value of options granted during the year		$ 6.20		$ 5.26		$ 5.09

The fair value of the options granted during 2004 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 1.56 percent to 1.60 percent, b) expected volatility of 27.7 percent, c) risk-free interest rate 2.47 percent and d) expected life of four years.

The fair value of the options granted during 2003 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 1.98 percent to 2.59 percent, b) expected volatility of 27.9 percent, c) risk-free interest rate 3.7 percent and d) expected life of eight years.

The fair value of the options granted during 2002 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 2.37 percent to 2.66 percent, b) expected volatility of 28.6 percent, c) risk-free interest rate 3.8 percent and d) expected life of eight years.

The following table summarizes certain information regarding stock options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number Outstanding at 12/31/04	Weighted Avg. Remaining Contractual Life	Weighted Avg. Exercise Price/share	Number Exercisable at 12/31/04	Weighted Avg. Exercise Price/share
$ 8.31 to $10.99	800	4.5	$ 8.84	800	$ 8.84
$11.00 to $15.99	69,600	6.4	$15.32	69,600	$15.32
$16.00 to $20.99	353,900	7.5	$18.07	353,900	$18.07
$21.00 to $25.99	12,000	8.6	$21.78	12,000	$21.78
$26.00 to $28.85	199,600	9.2	$28.51	—	$ —

Employees' Stock Ownership Plan

In July 2004, the Employees' Stock Ownership Plan ("ESOP") was merged with and into the Penn Virginia Corporation and Affiliated Companies' Employees' 401(k) Plan. Prior to termination of the ESOP, the unearned portion of the ESOP was reported as a component of "Unearned Compensation and ESOP" ($0.1 million at December 31, 2003) in the Shareholders' Equity section of the consolidated balance sheet. At December 31, 2004, there was no unearned portion of the ESOP.

Shareholder Rights Plan

In February 1998, the Board of Directors adopted a Shareholder Rights Plan (the "Plan") designed to prevent an acquirer from gaining control of the Company without offering a fair price to all shareholders. The Plan was amended in March 2002. Each common share outstanding has one right, and each right entitles the holder to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock, $100 par value, at a price of $100 subject to adjustment. The rights are not exercisable or transferable apart from the common stock until after a person or affiliated group has acquired or obtained the right to acquire fifteen percent or more (or 10 percent or more if such person or group has been deemed to be an "adverse person" as defined in the Plan) of our common stock. Each right will entitle the holder, under certain circumstances, to acquire at half the value, either 1) common stock of the Company, 2) a combination of cash, other property, or common stock or other securities of the Company, or 3) common stock of an acquiring person. Any such event would also result in any rights owned beneficially by the acquiring person or its affiliates becoming null and void. The rights expire in February 2008 and are redeemable under certain circumstances.

Restricted Units of PVR

The general partner granted 16,400 restricted units with a weighted average grant-date fair value of $34.66 per unit to directors and officers of the general partner in 2004. A restricted unit entitles the grantee to receive a common unit upon the vesting of the restricted unit. Restricted units vest upon terms established by the Partnership Compensation Committee, but in no case earlier than the conversion to common units of the Partnership's outstanding subordinated units. In addition, the restricted units will vest upon a change of control of the general partner or the Company. In November 2004, 25 percent of the outstanding units vested upon the conversion of 25 percent of subordinated units. If a grantee's employment with or membership on the Partnership's Board of Directors of the general partner terminates for any reason, the grantee's restricted units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. The general partner must issue new units or acquire existing common units to be delivered upon the vesting of restricted units. The general partner may purchase common units in the open market at the prevailing market price or directly from Penn Virginia Corporation or another third party, including units already owned by the general partner. The general partner is entitled to reimbursement by the Partnership for the cost incurred in acquiring such common units. Distributions payable with respect to restricted units may, at the Partnership's Compensation Committee's request, be paid directly to the grantee or held by the Partnership and made subject to a risk of forfeiture during the applicable restriction period.

The following table summarizes information with respect to restricted units awarded by the general partner.

	2004	
	Restricted Units	Fair Value/unit
Outstanding at beginning of year	46,450	$24.30
Granted	16,400	34.66
Vested	15,713	27.00
Forfeited	—	—
Outstanding at end of year	47,137	$27.00

Compensation expense related to restricted units totaled $0.4 million, $0.2 million, and $0.4 million for the years ended December 31, 2004, 2003 and 2002.

20. Accumulated Other Comprehensive Income

Comprehensive income represents certain changes in equity during the reporting period, including net income and charges directly to equity which are excluded from net income, including, but not limited to, unrealized gains and losses from marketable securities, price risk management assets and minimum pension liability adjustments. Reclassification adjustments represent gains or losses realized in net income for each respective year. For the three years ended December 31, 2004, the components of accumulated other comprehensive income are as follows (in thousands):

	Price Risk Management Assets	Minimum Pension Liability	Accumulated Other Comprehensive Income
Balance at December 31, 2001	$ 2,019	$(263)	$ 1,756
Hedging unrealized loss, net of tax of $2,160	(4,012)	—	(4,012)
Hedging reclassification adjustment, net of tax of $350	651	—	651
Pension plan adjustment, net of tax of $30	—	(56)	(56)
Balance at December 31, 2002	(1,342)	(319)	(1,661)
Hedging unrealized loss, net of tax of $2,428	(4,509)	—	(4,509)
Hedging reclassification adjustment, net of tax of $2,141	3,976	—	3,976
Pension plan adjustment, net of tax of $30	—	(56)	(56)
Balance at December 31, 2003	(1,875)	(375)	(2,250)
Hedging unrealized loss, net of tax of $1,214	(2,254)	—	(2,254)
Hedging reclassification adjustment, net of tax of $2,060	3,826	—	3,826
Pension plan adjustment, net of tax of $23	—	(42)	(42)
Balance at December 31, 2004	$ (303)	$(417)	$ (720)

21. Segment Information

Segment information has been prepared in accordance with SFAS No. 131, "Disclosure about Segments of an Enterprise and Related Information." Under SFAS No. 131, operating segments are defined as components of an enterprise about which separate financial information is available and is evaluated regularly by the chief operating decision maker, or decision-making group, in assessing performance. Our chief operating decision-making group consists of the Chief Executive Officer and other senior officials. This group routinely reviews and makes operating and resource allocation decisions among our oil and gas operations and PVR's coal royalty and land management operations. Accordingly, our reportable segments are as follows:

Oil and Gas—crude oil and natural gas exploration, development and production.

Coal Royalty and Land Management—the leasing of mineral interests and subsequent collection of royalties, the providing of fee-based coal handling, transportation and processing infrastructure facilities, and the development and harvesting of timber.

Corporate and Other—primarily represents corporate functions.

The following is a summary of certain financial information relating to our segments:

	Oil and Gas	Coal Royalty and Land Management	Corporate and Other	Consolidated
		(in thousands)		
As of and for the Year Ended December 31, 2004				
Revenues	$151,672	$ 75,630	$ 1,123	$228,425
Operating costs and expenses	57,668	16,479	10,334	84,481
Depreciation, depletion and amortization	35,886	18,632	434	54,952
Loss on assets held for sale	7,541	—	—	7,541
Impairment of oil and gas properties	655	—	—	655
Operating income (loss)	$ 49,922	$ 40,519	$ (9,645)	80,796
Interest expense				(7,672)
Interest income and other				1,101
Income before minority interest and taxes				$ 74,225
Total assets	$482,343	$284,435	$ 16,557	$783,335
Additions to property and equipment	123,977	1,088	$ 176	125,241
Equity investments	—	27,881	$ —	27,881
As of and for the Year Ended December 31, 2003				
Revenues	$124,822	$ 55,642	$ 820	$181,284
Operating costs and expenses	44,937	12,504	11,227	68,668
Depreciation, depletion and amortization	33,164	16,578	367	50,109
Impairment of oil and gas properties	406	—	—	406
Operating income (loss)	$ 46,315	$ 26,560	$(10,774)	62,101
Interest expense				(5,304)
Interest income and other				1,238
Income before minority interest and taxes				$ 58,035
Total assets	$405,753	$259,892	$ 18,088	$683,733
Additions to property and equipment	122,270	5,291	621	128,182
As of and for the Year Ended December 31, 2002				
Revenues	$ 71,512	$ 38,608	$ 837	$110,957
Operating costs and expenses	30,801	10,226	7,704	48,731
Depreciation, depletion and amortization	26,336	3,955	348	30,639
Impairment of oil and gas properties	796	—	—	796
Operating income (loss)	$ 13,579	$ 24,427	$ (7,215)	30,791
Interest expense				(2,116)
Interest income and other				2,039
Income before minority interest and taxes				$ 30,714
Total assets	$314,284	$266,576	$ 5,432	$586,292
Additions to property and equipment	51,581	92,817	343	144,741

Operating income does not include certain other income items, gain (loss) on sale of securities, interest expense, minority interest and income taxes.

For the year ended December 31, 2004, two customers of the oil and gas segment accounted for approximately $32.3 million and $28.2 million or 14 percent and 12 percent, respectively, of our consolidated net revenues.

For the year ended December 31, 2003, three customers of the oil and gas segment accounted for approximately $34.8 million, $24.2 million and $21.9 million or 19 percent, 13 percent and 12 percent, respectively, of our consolidated net revenues.

For the year ended December 31, 2002, two customers of the oil and gas segment accounted for approximately $29.4 million and $17.7 million, or 26 percent and 19 percent, respectively, of our consolidated net revenues.

22. Commitments and Contingencies

Rental Commitments

Minimum rental commitments for the next five years under all non-cancelable operating leases in effect at December 31, 2004, were as follows (in thousands):

Year ending December 31,	
2005	$1,607
2006	1,936
2007	1,048
2008	423
2009	405
Total minimum payments	$5,419

Rental commitments primarily relate to equipment, car and building leases. Also included are the Partnership's rental commitments, which primarily relate to reserve-based properties which are, or are intended to be, subleased by the Partnership to third parties. The obligation expires when the property has been mined to exhaustion or the lease has been canceled. The timing of mining by third party operators is difficult to estimate due to numerous factors. We believe the future rental commitments cannot be estimated with certainty; however, based on current knowledge, we believe the Partnership will incur approximately $0.4 million in rental commitments annually until the reserves have been exhausted.

Firm Transportation Commitments

In 2004, we entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to 10 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. We have an agreement to sell to a third party a portion of our capacity available under the firm transportation commitments. We also sell excess capacity to other third parties on a month-by-month basis. Our obligation for firm transportation commitments in effect at December 31, 2004, for the next five years and thereafter is as follows (in thousands):

Year ending December 31,	
2005 *	$ 1,479
2006	1,769
2007	1,609
2008	1,081
2009	1,081
Thereafter	5,314
Total	$12,333

* Net of $0.3 million to be received from a third party under agreement for use of our capacity.

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, management believes these claims will not have a material effect on the financial position, liquidity or operations.

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 closure of inactive pits and plugging of abandoned wells. 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 adverse impact on us. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

The operations of the Partnership's lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of the

Partnership's coal property leases impose liability for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. The lessees are bonded and have indemnified the Partnership against any and all future environmental liabilities. The Partnership regularly visits coal properties under lease to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the Partnership's lessees will be able to comply with existing regulations and does not expect any material impact on its financial condition or results of operations.

The Partnership has reclamation bonding requirements with respect to certain unleased and inactive properties. As of December 31, 2004 and 2003, the Partnership's environmental liabilities totaled $1.5 million and $1.6 million, respectively, which represents the best estimate of these liabilities as of those dates. Given the uncertainty of when the reclamation area will meet regulatory standards, a change in this estimate could occur in the future. The environmental liabilities are not covered by the indemnification agreement with Penn Virginia.

23. Subsequent Events

Sale of Texas Properties. On January 24, 2005, we completed the sale of certain oil and gas properties in Texas for cash proceeds of $9.7 million. These properties were classified as assets held for sale as of December 31, 2004, on the consolidated balance sheet. We recognized a loss of $7.5 million in 2004 to write down these properties to fair market value less costs to sell. As part of the sale agreement, we will receive a 20 percent net profits interest in one of the properties beginning January 1, 2006. In addition, the buyer has agreed to perform a waterflood technique on this property. If the buyer fails to complete the waterflood technique subject to certain deadlines, then under certain conditions the buyer would be liable to pay us additional proceeds of $0.5 million.

Cantera Acquisition. On March 3, 2005, PVR closed the Cantera Acquisition for $191 million in cash plus usual closing adjustments. As a result of this acquisition, the Partnership now owns and operates a business, under the name PVR Midstream LLC, consisting of a set of midstream assets that include approximately 3,400 miles of gas gathering pipelines that supply three natural gas processing facilities having 160 million cubic feet per day of total capacity (unaudited). The assets derive revenue primarily from the sharing of sales proceeds of natural gas and natural gas liquids under contracts with natural gas producers and from fees charged for gathering and processing of natural gas and other related services. The assets are located in four geographic regions: the Oklahoma and Texas Panhandles, north central Oklahoma, north central Texas and the Arkoma basin.

PVR Revolver and Term Loan. Concurrent with the closing of the Cantera Acquisition, PVR entered into a new unsecured $260 million, five-year credit facility with an expanded bank group led by PNC Capital Markets and RBC Capital Markets. The new credit facility consists of a $150 million revolving credit facility and a $110 million term loan. The term loan and a portion of the revolving credit facility were used to fund the Cantera Acquisition and to repay borrowings under the PVR Revolver.

Derivatives. In connection with the Cantera Acquisition, PVR entered into notional derivative contracts in January 2005 for approximately 75 percent of the net volume of natural gas liquids expected to be sold from April 2005 through December 2006. The underlying commodity prices that PVR expects to realize in future periods, after giving effect to the derivative contracts, are expected to exceed the commodity prices used in financial evaluation of the acquisition.

Since the time PVR entered into the derivative contracts, futures prices of natural gas liquids have increased significantly. As of March 2, 2005, the aggregate fair value of these derivative contracts was unfavorable to PVR.

Upon closing of the Cantera Acquisition and documenting hedge effectiveness, these derivative contracts are expected to qualify as cash flow hedges in accordance with SFAS No. 133. From the time the derivative contracts were executed until completion of the hedge effectiveness documentation, the derivative contracts do not qualify for hedge accounting. The unfavorable change in the derivative contracts' fair value was estimated to be approximately $8.9 million as of March 2, 2005. The fair value at the date the derivative contracts qualify for hedge accounting will be recognized as a non-cash reduction of earnings for PVR in the first quarter of 2005. The $8.9 million as of March 2, 2005, is the most recently available fair value estimate and is subject to change until the derivative contracts qualify for hedge accounting. All cash settlements of these derivative contracts will be paid or received over the 21-month term of the contracts.

Dividend Declared. In February 2005, the Company declared a quarterly dividend of $0.1125 per share payable March 17, 2005, to shareholders of record March 7, 2005.

24. Quarterly Financial Information (Unaudited)

Summarized Quarterly Financial Data:

	2003 Quarters Ended				2004 Quarters Ended			
	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30	Dec. 31
	(in thousands, except share data)							
Revenues	$48,016	$43,703	$42,021	$47,544	$55,626	$54,569	$52,741	$65,489
Operating income	$18,813	$14,807	$12,756	$15,725	$22,354	$25,665	$17,493	$15,284
Net income	$10,486	$ 6,362	$ 5,443	$ 6,231	$10,142	$12,080	$ 6,434	$ 4,699
Net income from continuing operations per share(a):								
Basic	$ 0.51	$ 0.35	$ 0.30	$ 0.35	$ 0.56	$ 0.66	$ 0.35	$ 0.26
Diluted	$ 0.51	$ 0.35	$ 0.30	$ 0.34	$ 0.55	$ 0.65	$ 0.35	$ 0.25
Net income per share(a):								
Basic	$ 0.59	$ 0.35	$ 0.30	$ 0.35	$ 0.56	$ 0.66	$ 0.35	$ 0.26
Diluted	$ 0.58	$ 0.35	$ 0.30	$ 0.34	$ 0.55	$ 0.65	$ 0.35	$ 0.25
Weighted average shares outstanding:								
Basic	17,904	17,952	17,992	18,054	18,168	18,293	18,357	18,414
Diluted	17,992	18,094	18,138	18,220	18,352	18,479	18,574	18,610

(a) The sum of the quarters may not equal the total of the respective year's net income per share due to changes in the weighted average shares outstanding throughout the year.

25. 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 Securities and Exchange Commission (SEC) and SFAS No. 69 "Disclosures about Oil and Gas Producing Activities". The amounts shown include our net working and royalty interest in all of our oil and gas operations.

Capitalized Costs Relating to Oil and Gas Producing Activities

	December 31,		
	2004	2003	2002
		(in thousands)	
Proved properties	$ 120,742	$ 123,302	$ 93,744
Unproved properties	61,013	60,042	57,575
Wells, equipment and facilities	392,230	316,257	228,608
Support equipment	3,461	3,689	3,433
	577,446	503,290	383,360
Accumulated depreciation and depletion	(148,212)	(116,998)	(86,586)
Net capitalized costs *	$ 429,234	$ 386,292	$296,774

* Net capitalized costs of $13.6 million relating to a transmission pipeline constructed in the Appalachian basin and placed into service near the end of 2004 were excluded from net capitalized costs at December 31, 2004.

In accordance with SFAS No. 143, as of January 1, 2003, the cost basis of oil and gas wells were increased by approximately $1.0 million. During 2004 and 2003, an additional $0.3 million and $0.4 million, respectively, was added to the cost basis of oil and gas wells for wells drilled.

Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Proved property acquisition costs	$ —	$ 35,131	$ 517
Unproved property acquisition costs	13,046	9,021	5,819
Exploration costs	26,429	21,401	7,843
Development costs and other*	82,048	67,783	41,750
Total costs incurred	$121,523	$133,336	$55,929

* Development costs of $13.7 million relating to a transmission pipeline constructed in the Appalachian basin and placed into service in November 2004 were excluded from 2004 costs incurred.

Results of Operations for Oil and Gas Producing Activities

The following schedule includes results solely from the production and sale of oil and gas and a non-cash charge for property impairments. It excludes corporate related general and administrative expenses and gains or losses on property dispositions. The income tax expense is calculated by applying the statutory tax rates to the revenues after deducting costs, which include depletion allowances and giving effect to oil and gas related permanent differences and tax credits.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Revenues	$151,786	$123,431	$71,178
Production expenses	23,728	21,928	15,390
Exploration expenses	26,058	15,503	7,614
Depreciation and depletion expense*	35,772	33,164	26,361
Impairment of oil and gas properties	655	406	796
	65,573	52,430	21,017
Income tax expense	25,967	21,338	6,566
Results of operations	$ 39,606	$ 31,092	$14,451

* Depreciation expense of $0.1 million relating to a transmission pipeline constructed in the Appalachian basin and placed into service in November 2004 was excluded from 2004 depreciation and depletion expense.

In accordance with SFAS No. 143, the combined depletion and accretion expense related to asset retirement obligations that was recognized during 2004 and 2003 in depreciation, depletion and amortization expense was approximately $0.5 million and $0.2 million, respectively.

Oil and Gas Reserves

The following schedule presents the estimated oil and gas reserves owned by us. This information includes our royalty and net working interest share of the reserves in oil and gas properties. Net proved oil and gas reserves for the three years ended December 31, 2004, were estimated by Wright and Company, Inc. All reserves are located in the United States.

There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and the timing of future development expenditures. 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. Proved oil and gas reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed oil and gas reserves are those reserves expected to be recovered through existing wells with equipment and operating methods.

Net quantities of proved reserves and proved developed reserves during the periods indicated are set forth in the tables below:

Proved Developed and Undeveloped Reserves	Oil and Condensate	Natural Gas	Total Equivalents
	(Mbbls)	(MMcf)	(MMcfe)
December 31, 2001	3,920	229,253	252,773
Revisions of previous estimates	—	(3,339)	(3,339)
Extensions, discoveries and other additions	1,944	33,197	44,861
Production	(364)	(18,715)	(20,899)
Purchase of reserves	29	1,071	1,245
Sale of reserves in place	(168)	(212)	(1,220)
December 31, 2002	5,361	241,255	273,421
Revisions of previous estimates	101	(5,302)	(4,696)
Extensions, discoveries and other additions	232	53,088	54,480
Production	(625)	(20,094)	(23,844)
Purchase of reserves	1,567	14,354	23,756
Sale of reserves in place	(2)	(232)	(244)
December 31, 2003	6,634	283,069	322,873
Revisions of previous estimates	(418)	(13,669)	(16,177)
Extensions, discoveries and other additions	532	70,010	73,202
Production	(396)	(22,079)	(24,455)
Purchase of reserves	—	—	—
Sale of reserves in place	(9)	(1,279)	(1,333)
December 31, 2004 *	6,343	316,052	354,110
Proved Developed Reserves:			
December 31, 2002	2,943	198,733	216,391
December 31, 2003	3,346	230,958	251,034
December 31, 2004	2,895	243,480	260,850

* Included in these amounts as of December 31, 2004, were 3,666 Mbbls of crude oil and condensate and 5,203 Mmcf of natural gas related to the Texas properties sold effective in the first quarter of 2005 (see Note 23, "Subsequent Events").

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and gas reserves. Future cash inflows were computed by applying year-end prices of oil and gas to the estimated future production of proved oil and gas 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 oil and gas 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 percent annual rate.

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Future cash inflows	$2,310,163	$1,965,224	$1,372,935
Future production costs	(460,729)	(392,193)	(263,705)
Future development costs	(123,928)	(70,105)	(51,151)
Future net cash flows before income tax	1,725,506	1,502,926	1,058,079
Future income tax expense	(455,328)	(407,411)	(285,633)
Future net cash flows	1,270,178	1,095,515	772,446
10% annual discount for estimated timing of cash flows	(680,525)	(583,823)	(417,523)
Standardized measure of discounted future net cash flows*	$ 589,653	$ 511,692	$ 354,923

* The amount at December 31, 2004, includes $36.8 million related to the Texas properties sold effective in the first quarter of 2005 (see Note 23, "Subsequent Events").

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Sales of oil and gas, net of production costs	$(128,058)	$(101,503)	$ (55,788)
Net changes in prices and production costs	46,269	92,640	203,588
Extensions, discoveries and other additions	177,914	142,921	82,808
Development costs incurred during the period	14,705	15,503	16,393
Revisions of previous quantity estimates	(38,771)	(10,380)	(6,513)
Purchase of minerals-in-place	—	68,071	2,901
Sale of minerals-in-place	(3,722)	(36)	(328)
Accretion of discount	69,585	48,114	24,254
Net change in income taxes	(20,779)	(57,942)	(72,614)
Other changes	(39,182)	(40,619)	(28,721)
Net increase (decrease)	77,961	156,769	165,980
Beginning of year	511,692	354,923	188,943
End of year	$ 589,653	$ 511,692	$354,923

As required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," changes in standardized measure relating to sales of reserves are calculated using prices in effect as of the beginning of the period and changes in standardized measure relating to purchases of reserves are calculated using prices in effect at the end of the period. Accordingly, the changes in standardized measure for purchases and sales of reserves reflected above do not necessarily represent the economic reality of such transactions. See the disclosure of "Costs Incurred in Certain Oil and Gas Activities" earlier in this Note and the statements of cash flows in the consolidated financial statements.

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

None.

Item 9A—*Controls and Procedures*

(a) Management's Assessment on Internal Control Over Financial Reporting

During the course of their audit of our consolidated financial statements as of and for the year ended December 31, 2004, KPMG LLP ("KPMG") discovered that, during the fourth quarter, we incorrectly calculated the loss associated with the sale of certain assets, which were previously classified as assets held for sale. After reviewing the relevant accounting literature, we agreed that we had incorrectly calculated the loss on the asset sale and recorded the correcting entry prior to the release of our financial information. We determined that the accounting error was the result of a lack of review by the appropriate company personnel of the accounting for non-routine transactions, and we concluded that a deficiency existed with respect to our internal control over financial reporting. We determined that this deficiency constituted a material weakness in our internal control over financial reporting as of December 31, 2004.

Our management, including our Chief Executive Officer and our Chief Financial Officer, are 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, 2004. This evaluation was completed in accordance with the framework established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of the material weakness described above, our management has concluded that, as of December 31, 2004, our internal control over financial reporting was not effective. KPMG LLP has issued an attestation report on our management's assessment of our internal control over financial reporting.

(b) Changes in Internal Controls Over Financial Reporting

The material weakness referred to in Item 9A(a) occurred in connection with a non-routine sale of property (a "non-routine transaction") entered into by the Company. Accordingly, we have put in place the following process to remediate the material weakness: Our accounting staff will carefully review the key terms of each non-routine transaction, and will document in a memorandum (i) all such key terms, (ii) our analysis of and research relating to the accounting issues involved in such transaction and (iii) our conclusion as to the accounting treatment and financial statement disclosure of such transaction. This memorandum will be reviewed by our Controller and Chief Financial Officer prior to the recording of any ledger entries relating to such transaction.

In addition, during the quarter ended December 31, 2004, we updated our software and implemented stricter user access controls in connection with our remediation of the material weakness we identified and disclosed in the quarter ended September 30, 2004.

(c) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures as of December 31, 2004. Based on that evaluation and because of the material weakness described in Item 9A(a) above, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2004, such disclosure controls and procedures were not effective to ensure that material information relating to the Company, including its consolidated subsidiaries, was accumulated and communicated to our management and made known to our Chief Executive Officer and Chief Financial Officer.

Item 9B—*Other Matters*

None.

PART III

Items 10, 11, 12 and 13—*Directors and Executive Officers of the Registrant, Executive Compensation, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and Certain Relationships and Related Transactions*

Except for information concerning executive officers of the Company included as an unnumbered item in Part I hereof, 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 report.

Item 14—*Principal Accountant Fees and Services*

The following table presents fees for professionals audit services rendered by KPMG LLP for the audit of the Company's annual financial statements for 2004 and 2003, and fees billed for other services rendered by KPMG LLP.

	2004	2003
Audit fees(1)	$1,121,400	$557,350
Audit related fees(2)	19,200	10,000
Tax fees(3)	—	66,529
Total Fees	$1,140,600	$633,879

(1) Audit fees include fees for the audits of the Company's and the Parternship's financial statements, the audit of the Company's and the Partership's internal controls over financial reporting (2004 only), consents for registration statements, comfort letters and related travel expenses. In 2004, our audit fees pertaining to the audit of internal controls over financial reporting were $505,000. Audit fees related to the Partnership were $434,800 and $279,950 for the years ended December 31, 2004 and 2003, respectively. The Partnership reimbursed the Company for these amounts. In addition to audit fees paid to KPMG LLP shown in the table above, we paid professional fees to third-party consultants of approximately $294,000 and $151,000 in 2004 and 2003, respectively, related to compliance with the Sarbanes-Oxley Act of 2002.

(2) Audit-related fees of $10,000 in 2004 and 2003 pertain to debt compliance letters issued by KPMG under the Company's credit facility and the Partnership's senior notes. The Partnership's fees were $5,000, and it reimbursed the Company for this amount. Also included in 2004 audit-related fees is $9,200 for accounting consultations related to acquisitions by the Partnership. The Partnership also reimbursed this amount to the Company.

(3) Comprised of fees for tax consulting and tax compliance services.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Auditors

The Audit Committee's policy is to pre-approve all audit and audit-related services provided by the independent auditors. These services may include audit services, audit-related services, tax services and other services. The Audit Committee may also pre-approve particular services on a case-by-case basis. The independent auditors are required to periodically report to the Audit Committee regarding the extent of services provided by the independent auditors in accordance with such pre-approval. The Audit Committee may also delegate pre-approval authority to one or more of its members. Such member(s) must report any decisions to the Audit Committee at the next scheduled meeting.

PART IV

Item 15—*Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(a) Financial Statements

1. Financial Statements—The financial statements filed herewith are listed in the Index to Financial Statements on page 51 of this report.

2. All schedules are omitted because they are not required, inapplicable or the information is included in the consolidated financial statements or the notes thereto

3. Exhibits

(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).

(3.2) 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).

(3.3) 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).

(3.4) Amended and Restated Bylaws of Registrant (incorporated by reference to Exhibit 3(ii) to Registrant's Report on Form 8-K filed on November 29, 2004).

(4.1) Rights Agreement dated as of February 11, 1998 between Penn Virginia Corporation and American Stock Transfer & Trust Company, as Agent (incorporated by reference to Exhibit 1.1 to Registrant's Registration Statement on Form 8-A filed on February 20, 1998).

(4.2) Amendment No. 1 to Rights Agreement dated March 27, 2002 by and between Penn Virginia Corporation and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 4.1 of Registrant's Report on Form 8-K filed on March 28, 2002).

(10.1) Amended and Restated Credit Agreement dated as of December 4, 2003, among Penn Virginia Corporation, the lenders party thereto, Bank One, NA, as Administrative Agent, Wachovia Bank, National Association, as Syndication Agent, Royal Bank of Canada, BNP Paribas and Fleet National Bank, as Documentation Agents, and Banc One Capital Markets, Inc. and Wachovia Capital Markets, LLC, as Co-Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.1 of Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).

(10.2) Penn Virginia Corporation and Affiliated Companies' Employees' 401(k) Plan, as amended (incorporated by reference to Exhibit 10.3 of Registrant's Annual Report on Form 10-K for the year ended December 31, 2001).

(10.3) Penn Virginia Corporation 1995 Fourth Amended and Restated Directors' Stock Compensation Plan.

(10.4) Penn Virginia Corporation Amended 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.7 of Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(10.5) Omnibus Agreement ("Omnibus Agreement") dated October 30, 2001 among Penn Virginia Corporation, Penn Virginia Resource GP, LLC, Penn Virginia Operating Co., LLC and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 10.2 to Registrant's Report on Form 8-K filed on November 14, 2001).

(10.6) Amendment to Omnibus Agreement (incorporated by reference to Exhibit 10.9 of Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(10.7) Penn Virginia Corporation 1994 Stock Option Plan, as amended (incorporated by reference to Exhibit 10.5 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(10.8) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and A. James Dearlove (incorporated by reference to Exhibit 10.1 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.9) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and Frank A. Pici (incorporated by reference to Exhibit 10.2 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.10) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.3 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.11) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.4 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.12) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and Keith D. Horton (incorporated by reference to Exhibit 10.5 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.13) Form of restricted stock award agreement.

(10.14) Form of deferred common stock award agreement.

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

(14) Penn Virginia Corporation Executive and Financial Officer Code of Ethics (incorporated by reference to Exhibit 14 of Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).

(21) Subsidiaries of Registrant.

(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.

(b) Reports on Form 8-K

On November 4, 2004, the Company furnished a Current Report on Form 8-K announcing that it issued a press release regarding its financial results for the three and nine months ended September 30, 2004. On November 5, 2004, the Company furnished an amendment to this Form 8-K announcing that it issued a press release to correct an error in the fourth quarter 2004 guidance table published in the November 3, 2004, press release.

On December 2, 2004, the Company furnished a Current Report on Form 8-K announcing that it amended its Bylaws to increase the number of directors.

On December 9, 2004, the Company furnished a Current Report on Form 8-K announcing the election of two new board members.

On February 2, 2005, the Company furnished a Current Report on Form 8-K announcing the resignation of one of its directors.

On January 31, 2005, and February 15, 2005, the Company furnished a Current Report on Form 8-K an amendment thereto on Form 8-K/A, respectively, regarding a change to the compensation of the directors of the Company.

On February 10, 2005, the Company furnished a Current Report on Form 8-K announcing that it issued a press release regarding its financial results for the year ended December 31, 2004.

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Pictured from left to right: Edward B. Cloues, II, Keith D. Horton, Marsha R. Perelman, Robert Garrett, A. James Dearlove, Gary K. Wright, Steven W. Krablin, Joe N. Averett, Jr.

DIRECTORS

Robert Garrett[1,2]
Chairman of the Board of the Company and President of AdMedia Partners, Inc.

Joe N. Averett, Jr.[4]
Retired. Former President, CEO and Director, Crystal Gas Storage, Inc.

Edward B. Cloues, II[2,3]
Chairman and Chief Executive Officer of K-Tron International, Inc.

A. James Dearlove
President and Chief Executive Officer of the Company and Chairman and Chief Executive Officer of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P.

Keith D. Horton
Executive Vice President of the Company and President and Chief Operating Officer of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P.

Steven W. Krablin[1,3]
Senior Vice President and Chief Financial Officer, National Oilwell, Inc.

Marsha Reines Perelman[1,3,4]
Chief Executive Officer of Woodforde Management, Inc.

Gary K. Wright[2,3,4]
Former President, LNB Energy Advisors, former Southwest Managing Director for Chase Manhattan Bank Global Oil and Gas Group and former Manager of Chemical Bank Worldwide Energy Group

1 Member of the Nominating & Governance Committee
2 Member of the Compensation & Benefits Committee
3 Member of the Audit Committee
4 Member of the Oil & Gas Committee

MANAGEMENT

A. James Dearlove
President and Chief Executive Officer

Frank A. Pici
Executive Vice President and Chief Financial Officer

H. Baird Whitehead
Executive Vice President

Keith D. Horton
Executive Vice President

Nancy M. Snyder
Senior Vice President, General Counsel and Corporate Secretary

Ronald K. Page
Vice President, Corporate Development

Dana G Wright
Vice President and Controller

MAJOR SUBSIDIARIES

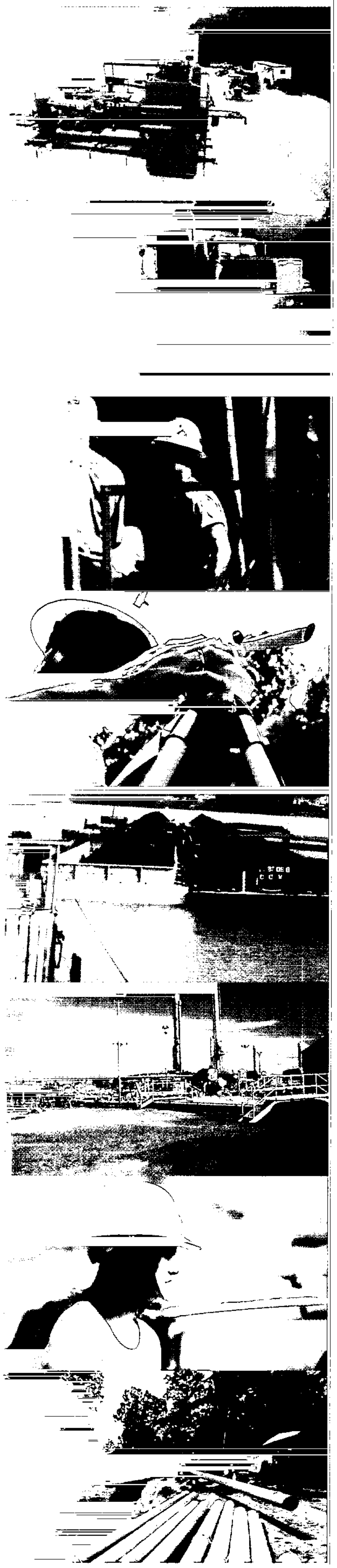
Penn Virginia Oil and Gas Corporation
Penn Virginia Resource GP, LLC

ANNUAL MEETING

Penn Virginia Corporation's Annual Meeting will be held
10 a.m. May 3, 2005
Marriott Philadelphia West
111 Crawford Avenue
West Conshohocken, PA 19428
Telephone: (610) 941-5600
Facsimile: (610) 941-1060

TRANSFER AGENT & REGISTRAR

American Stock Transfer & Trust Company
Mailing Address:
59 Maiden Lane
New York, NY 10038
Telephone: (800) 937-5449
Facsimile: (718) 236-2641



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