Penn Virginia Corporation

Unique in Energy

2001 Annual Report

In millions except per share data	2001	2000	1999[1]
Financial Data			
Revenues[2]	$ 96.6	$ 106.0	$ 47.4
Operating Income[3]	1.2	65.6	20.7
Net Income[4]	34.3	39.3	14.5
Discretionary Cash Flow[5]	48.1	37.8	25.3
Common Share Data			
Net Income, Basic	$ 3.92	$ 4.76	$ 1.73
Net Income, Diluted	3.86	4.69	1.71
Discretionary Cash Flow[5]	5.40	4.52	2.99
Dividends Paid	0.90	0.90	0.90
Average Shares Outstanding	8.9	8.4	8.5
Capitalization			
Net Long-term Debt[6]	3.5	47.5	78.5
Shareholder's Equity	185.5	171.2	154.3
Total Capitalization	189.0	218.7	232.8
Percent of Net Long-term Debt to Total Capitalization	1.9%	21.7%	33.7%
Summary Operating Data			
Production			
Oil and Condensate (Mbbls)	164	31	32
Natural Gas (Bcf)	13.1	11.6	8.7
Total Oil and Gas Production (Bcfe)	14.1	11.8	8.9
Coal Produced by Lessees (Millions of tons)	15.3	12.5	8.6
Prices			
Oil and Condensate ($/Bbl)	$ 22.94	$ 26.84	$ 14.47
Natural Gas ($/Mcf)	4.06	3.95	2.46
Coal Royalties ($/Ton)	2.11	1.94	2.07
Estimated Reserves			
Oil and Condensate (MMbbls Proved)	3.9	0.1	0.4
Natural Gas (Bcf Proved)	229.3	174.2	185.2
Total Proved Oil and Gas Reserves (Bcfe)	252.8	174.7	187.4
Coal (Millions of Recoverable Tons)	492.8	480.0	488.4

[1]Certain 1999 amounts have been reclassified to conform to the current presentation.

[2]Operating revenues, which exclude dividend income and gain on sale of properties, were $95.9 million, $78.6 million and $44.8 million for 2001, 2000 and 1999, respectively.

[3]Operating income in 2001 included a $33.6 million impairment on oil and gas properties. Operating income in 2000 included a $23.9 million gain on the sale of certain oil and gas properties.

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

[5]Includes Net Income before nonoperating items plus noncash charges and dry hole expense.

[6]Net of $43.4 million cash equivalents held as collateral for the debt as of December 31, 2001.

Abbreviations:

Bbl - Barrel
Mbbl - Thousand barrels
MMbbl - Million barrels
Bcf - Billion Cubic Feet
Bcfe - Billion Cubic Feet Equivalent
Mcf - Thousand Cubic Feet
Mcfe - Thousand Cubic Feet Equivalent

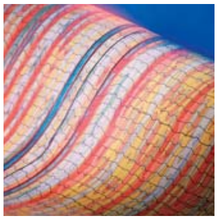
Penn Virginia Corporation (NYSE Symbol: PVA) is an energy company engaged in the exploration, acquisition, development and production of crude oil and natural gas. Through its ownership in Penn Virginia Resource Partners, L.P. (NYSE: PVR), PVA is also in the business of managing coal and timber properties.

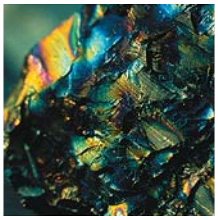
Year In Review

Penn Virginia Corporation made major strides during 2001 to execute its underlying strategy and to set the stage for the future expansion of its oil and gas as well as its coal land management business. Among the Company's more important accomplishments during the year were the acquisition of Synergy Oil and Gas, Inc., a Texas-based independent oil and gas producer, and the highly successful initial public offering of forty-eight percent of Penn Virginia Resource Partners, L.P., which included our coal reserves, timber and related assets. Other highlights included: an important acquisition of additional coal reserves, the disposition of our position in Norfolk Southern Company, record levels of oil and gas production, revenues and cash flow as well as record levels of coal royalties and related earnings.

Oil and Gas

A Company record 119 net wells were drilled in 2001 of which 58 were in Appalachia, 55 in Mississippi and six in Texas. Production in 2001 was 14.1 Bcfe, also a record. Penn Virginia began exploration initiatives in various deeper formations in Appalachia and undertook a technically innovative approach to expand its coal bed methane program. In Mississippi, efforts continued to increase the Company's presence. The primary focus of Penn Virginia's activities in Texas was to develop the Synergy assets into a platform for growth.





Coal Land Management

Production from Penn Virginia's coal properties was a record 15.3 million tons. Operating income associated with that production was $25.2 million, also a record.

In June Penn Virginia acquired approximately 53 million tons of proved, high quality coal reserves for $33 million. The new reserves are located contiguous to the Company's Coal River property in southern West Virginia and, although currently idled, are expected to be an important part of the future growth of Penn Virginia Resource Partners.

Financial Flexibility

In May, Penn Virginia sold its interest in Norfolk Southern Company generating a pre-tax gain of $54.7 million. This divestiture along with the proceeds from the initial public offering of Penn Virginia Resource Partners made it possible for Penn Virginia to enter 2002 with a net debt to capitalization ratio of two percent, despite two major acquisitions and a record level of capital spent on drilling.

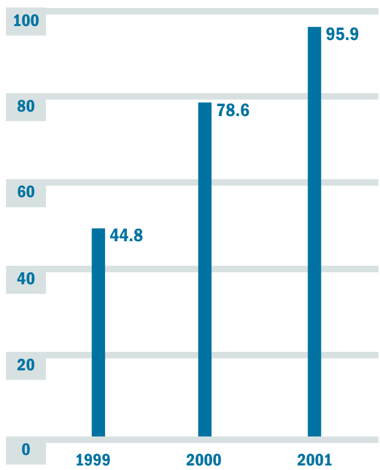
As an upstream supplier of natural gas, oil, and

Dear Fellow Shareholders:

For the past few years we have been consistently and successfully transforming and growing Penn Virginia. In 2001, the Company accelerated the process. The acquisition of Synergy Oil and Gas, Inc. provides a platform for growth in the southwest oil and gas business. Significant exploration initiatives were begun in Appalachia with the goal of expanding our oil and gas presence in the east. The initial public offering of Penn Virginia Resource Partners, L.P. (NYSE: PVR) more fully recognized the value of our coal, timber and land assets and created a separate growth vehicle to add to those assets. An important coal acquisition was completed in July. The sale of the Norfolk Southern stock simplified the Company and monetized a nonstrategic asset which we redeployed into our oil and gas drilling program.

Penn Virginia's 2001 operating revenues and cash flow were at all time highs, fueled by record levels of oil, gas and coal production. Earnings levels did not keep pace with these operating growth factors, however, primarily due to a $21.8 million after-tax impairment charge we recorded against our oil and gas assets caused by low commodity prices at the end of 2001. Even considering this non-cash charge, we believe Penn Virginia had an extraordinary year of value creation during 2001.

Operating Revenues*
Dollars in millions



Excludes dividend income and gain on sale of properties.

Unique in Energy

For several years Penn Virginia has taken a balanced approach to the energy business. By being exposed to natural gas, oil and coal the Company benefits from the upside potential of the natural gas business while maintaining more stability in its earnings and cash flow due to the historically less volatile coal royalty business.

Although it has been slowed recently by the recession, electricity usage in the U.S. has been growing at over two percent annually for the past few years. Several new electric power generating projects are on the drawing boards, being permitted or under construction. Virtually all of these plants will be fueled by either coal or natural gas.

Although a variety of factors including costs, the state of the economy, market access and environmental issues will decide which facilities ultimately get built, Penn Virginia should benefit from the increased usage of electricity.

The aftermath of the tragic events of September 11 and continued unrest in the Middle East has led to renewed calls for less dependence on foreign oil. As a practical matter, for the next 20 years or more the two fuels the U.S. will have to rely on to achieve that goal are natural gas and coal.

Penn Virginia Resource Partners, L.P.

On October 25, 2001, Penn Virginia launched Penn Virginia Resource Partners, L.P. to engage in the business of coal royalty-based land management. Penn Virginia maintained a 52 percent interest in PVR including a 100 percent interest in

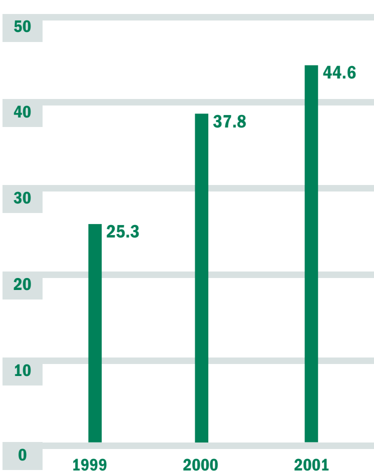
coal, Penn Virginia is truly "unique in energy."

the general partner. The offering was heavily oversubscribed and based on its one and ten day price performance was among the top two or three master limited partnership (MLP) IPOs of the past decade. Penn Virginia netted $142 million in the offering after all fees and expenses were paid.

PVR was formed to provide a growth vehicle for Penn Virginia's coal land management business. Although the size of our coal holdings have approximately doubled since 1996, we believe the low cost of capital inherent in an MLP and the liquidity offered by the MLP units should allow for accelerated growth. PVR's payout to its public unit holders will impact Penn Virginia's earnings

Discretionary Cash Flow*

Dollars in millions



**Net income before nonoperating items plus noncash charges and dry hole expenses.*

relative to what they would have been if we had not monetized 48 percent of our coal business. However, because of the advantages of the partnership structure in making acquisitions, we believe the coal land management business will ultimately contribute more cash to Penn Virginia as PVR than would have been possible under the former structure.

The capital raised in the IPO was redeployed into our oil and gas business allowing us to make a significant move outside Appalachia while maintaining a strong balance sheet.

Another effect of the MLP was to more fully value the coal and land assets of Penn Virginia. The price of Penn Virginia stock was $36.50 per share prior to the IPO and was $36.85 per share ten days afterwards. Thus without affecting Penn Virginia's stock price, over $140 million of new value was created.

Strategy

As this winter has shown, oil and gas prices are volatile and reinvestment requirements are high. Despite the difficulties, companies in the oil and gas business can and do succeed for their shareholders, particularly if viewed from price cycle to price cycle.

A. James Dearlove
President and Chief Executive Officer

Robert Garrett
Chairman

Penn Virginia is committed to succeed in the energy business. The elements of our strategy are simple:

- Use our strong balance sheet and cash flow to fund internally generated projects and to support opportunistic acquisitions.
- Balance oil and gas price volatility by maintaining a strong presence in the historically more stable coal royalty business.
- Be value, not size driven. There are benefits to being bigger, however, we believe it is more beneficial to be value creators. Investments must make economic sense based on reasonably conservative price expectations.

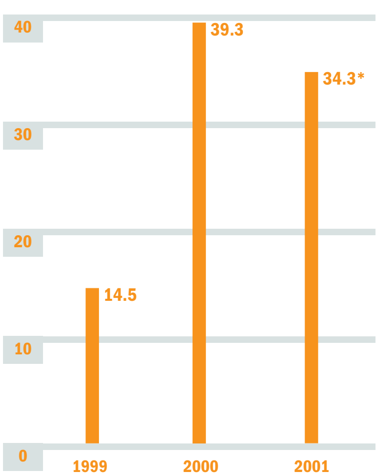
• Balance risk. An optimum portfolio has a full spectrum of risk/reward opportunities.
• Be fiscally conservative. Avoid becoming over leveraged, particularly in light of the industry's high reinvestment needs and volatile price environment. Fiscal prudence includes some amount of hedging to protect acquisitions and/or drilling programs.
• Hire and retain the best people.

Board Changes

Three distinguished members of the Board of Directors did not stand for reelection in 2001. Messers. Lennox K. Black, John D. Cadigan and John A. H. Shober each provided many years of steady guidance and wise counsel to Penn Virginia. Mr. Shober served the Company for 30 years, including as its President and CEO from 1989 until 1992 and as a Director from 1992 until 2001. Mr. Black served on the Board from 1984 until 2001 and was CEO and Chairman of the Board from 1992 until 1996. Mr. Cadigan joined the Board in 1986 and brought it both business acumen and a deep knowledge of oil and gas. They will all be greatly missed.

Mr. Edward B. Cloues, II joined the Board of Directors on December 5, 2001. Since 1998, Mr. Cloues has been Chairman of the Board and Chief Executive Officer of K-Tron International, Inc., a Nasdaq National Market company involved in the design and manufacture of high performance materials handling equipment for the process industries. In addition to his management and operations experience, Mr. Cloues, 53, brings over 25 years of experience in mergers and acquisitions, much of it gained during his partnership at Morgan, Lewis & Bockius LLP.

Earnings
Dollars in millions



*Includes $21.8 mm after tax effect of non-cash impairment charge.

Outlook

This was a year of considerable achievement and we believe the future is bright. At the time this letter is being written natural gas prices are depressed relative to late 2000 and early 2001. However, as the economy improves, the expected demand for natural gas augers well for the long term.

We have some exciting exploration projects underway and plan to maintain the momentum. Synergy has provided a platform for growth in the southwest and we are also looking to expanding in Appalachia and Mississippi.

PVR provides Penn Virginia with a growth vehicle for its coal, timber and land business. We expect to grow the core business and look in some new directions as well.

Unlike many of its competitors, the Company is virtually debt free and thus has the financial strength to take advantage of opportunities to create shareholder value.

The table is set, now it's about execution. As always we appreciate the diligent efforts of Penn Virginia's dedicated employees and the loyalty and support of you, our shareholders.

A. James Dearlove
President and Chief Executive Officer

Robert Garrett
Chairman

In 2001, Penn Virginia continued to increase its inventory of oil and gas properties and exploration prospects.

In 2001, Penn Virginia continued the expansion of its eastern oil and gas operations and added significantly to its southwestern presence with the acquisition of Synergy Oil and Gas, Inc. In the east a number of projects were undertaken to explore for deeper formations, particularly the Trenton/Black River in New York and West Virginia as well as the Knox formation in Virginia and Tennessee. Evaluation of a technologically innovative horizontal drilling technique for producing coal bed methane was successfully initiated.

In Mississippi, the Company expanded its leasehold at Gwinville and is seeking additional prospects. Parts of Mississippi have not been as actively explored as other regions of the country and may offer Penn Virginia the opportunity to create an important niche.

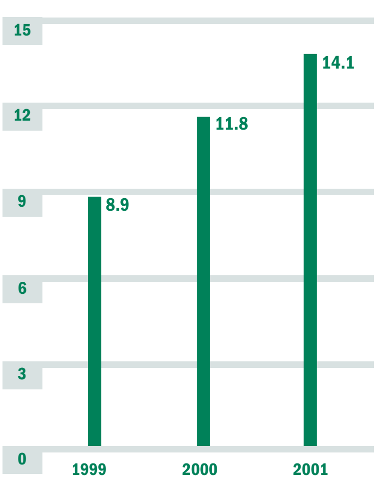
The south Texas-based Synergy Oil and Gas purchase has given Penn Virginia an important platform for future growth. The acquisition was completed on July 23, 2001 for a cost of $112 million. Proved reserves of 59.6 Bcfe were added, and Penn Virginia estimates another 45 Bcfe were in the probable and possible reserve categories at December 31, 2001. The assets acquired in the acquisition give Penn Virginia a producing interest in 25 oil and gas fields, 20 of which are in the Gulf Coast area of south Texas. These fields have significant exploration potential, with 27,300 net developed acres and 10,000 undeveloped acres as well as 214 square miles of proprietary 3-D seismic data. The proximity of these assets to other areas of interest to Penn Virginia also was an important consideration in the purchase.

Penn Virginia's total reserves at year end were 253 Bcfe, an increase of 45 percent over the 2000 total. Approximately 91 percent of the Company's reserve are natural gas.

Production in 2001 was a Company record 14.1 Bcfe, a 19 percent increase over 2000 and includes a five month contribution from Synergy. Eastern production was up slightly to 11.9 Bcfe in 2001, which is significant in that the eastern operations were able to make up for the producing fields the Company sold in December 2000.

Penn Virginia drilled 154 gross (119 net) wells in 2001, including 130 gross (101 net) development wells and 24 gross (18 net)

Oil & Gas Production



exploratory wells. Of the development wells 125 gross were productive and 19 of the exploration wells were productive. The Company replaced 660 percent of its production from all sources (acquisitions, extensions, discoveries and other additions) at a reserve replacement cost of $1.26 per Mcfe (excluding unproved property costs and deferred taxes on the Synergy acquisition). Excluding acquisitions, Penn Virginia replaced 238 percent of its production during 2001 at a finding and development cost of $1.41 per Mcfe (excluding Synergy unproved property costs).

The price of natural gas went through a wild gyration in 2001. The average price Penn Virginia received in 2001 was $4.06 per Mcf, compared to $3.95 per Mcf in 2000. However, year end prices, which dramatically affect the SEC mandated technique for estimating reserves, were $2.65 per Mcf on December 31, 2001 compared to $9.91 per Mcf on December 31, 2000. The lower prices caused the Company to review the carrying value of its oil and gas fields, resulting in a non-cash pre-tax impairment charge of $33.6 million. This charge was related primarily to the Synergy acquisition, which was made when the commodity price outlook was higher than at year-end 2001. Future periods will benefit from this charge in the form of reduced depreciation, depletion and amortization expenses. At year end 2001, Synergy's proved reserves were higher than estimated at the acquisition.

Penn Virginia put in place various hedges for its oil and gas production, resulting in a revenue improvement of $1.9 million in 2001. As of March 15, 2002, the Company had in place natural gas hedge positions for 2002 covering approximately 22,700 MMbtu per day. These positions provide average floor and ceiling prices of $2.95 and $3.50 per MMbtu, respectively, and cover approximately 41 percent of anticipated natural gas production for the year. Approximately 750 barrels of oil per day is hedged for 2002 at average floor and ceiling prices of $21.31 and $25.72 per barrel, respectively.

A position was also in place for 2003 covering 5,400 MMbtu per day at an average floor price of $2.75 per MMbtu and a ceiling price of $4.48 per MMbtu.

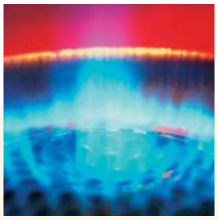
In 2002, the Company expects to drill between 110 and 130 gross (75 to 90 net) wells, of which 25 to 30 gross (15 to 20 net) would be development wells. The approved capital budget in 2002 is $51.1 million, not including acquisitions.

Penn Virginia Resource Partners, L.P. (NYSE: PVR) celebrates IPO at the NYSE. In honor of the occasion, A. James Dearlove, CEO, rings the opening bell.

Our plan is for PVR to be a growth MLP. We expect to consistently grow distributions, which should increase the value of the units, making them a more powerful acquisition currency. The low cost of capital inherent to MLP's allows us to be more competitive in making acquisitions. Finally, our coal is now a "pure play," which we believe adds to the appeal of units to a spectrum of potential coal owners.

Coal

Land Management



The creation of Penn Virginia Resource Partners, L.P. gives the Company a potent growth vehicle.

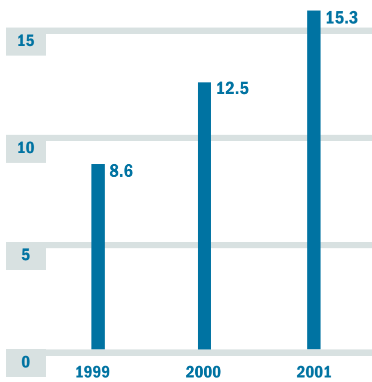
Penn Virginia will continue to participate in the coal industry through its ownership of 52 percent of Penn Virginia Resource Partners, L.P. (PVR), a master limited partnership the Company sponsored. Penn Virginia also owns 100 percent of the general partner.

PVR owns or controls approximately 493 million tons of high quality, environmentally compliant coal reserves concentrated in Central Appalachia and leases mining rights to a diverse group of operators who pay a royalty based on a percentage of the sales price. Since PVR does not engage in mining and its properties have a very small reinvestment requirement, the Partnership has high operating margins and provides relatively stable and predictable earnings and free cash flow. PVR's proven land management skills allow it to foster growth and optimize the value of its properties.

In 2001, coal royalties were a record $32.4 million, an increase of 33 percent over 2000. Most of the increase reflected expanded production from Company properties owned

Coal Production

In millions tons



prior to 2001. However, an important addition is the newly acquired Fork Creek property in West Virginia. The acquisition of approximately 53 million tons of reserves for $33 million was completed in May of 2001.

In early 2002, the operator of Fork Creek encountered financial difficulty and filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. Operations at the Fork Creek property were idled on March 4, 2002. However, Penn Virginia believes the quality of the Fork Creek reserves and the $80 million the operator invested in mine development and infrastructure bode well for the future of the properties.

Penn Virginia, through PVR, will continue to seek acquisitions of high quality coal reserves and associated assets. The Company expects that the partnership structure will facilitate acquisitions to the benefit of all PVR unitholders.

Eastern spot market coal prices began 2001 at very high levels. Quotes of $50 per ton or more for high-quality coals were not uncommon. Since most eastern coal is sold under one or two year contracts the effect of the high spot prices was not that dramatic. Between 70 and 80 percent of the coal mined on Penn Virginia property is sold under contracts of one year or more.

Spot prices have come down during the year and currently hover around $30 per ton, which is still an improvement over 1999/2000. As a result of the unusual spot price volatility and the concern of the utilities over securing adequate coal supplies, new contracts are typically being priced in the low thirty dollar per ton range, versus the mid to high-twenties of the 1990's. The new contracts tend to be longer, often three years instead of one or two. Based on these factors, PVR expects its average royalty in 2002 to be in the $2.00 to $2.05 per ton range, down from the $2.11 per ton of 2001, and above the $1.94 per ton received in 2000.

There remain concerns about the adequacy of supply of eastern coal over the next few years. The mountain top removal verdict, which made obtaining mining permits in West Virginia extraordinarily difficult, was overturned on jurisdictional grounds, and the United States Supreme Court has refused to hear an appeal. It is unclear whether the case will be retried in state court. Of late, the pace of permitting is picking up slightly. Also, the state of the West Virginia considered legislation during its last session that would have significantly increased the scope of powers available to enforce the current weight restrictions on trucks carrying coal. Although no such legislation was approved, the issue remains controversial and similar legislation could be proposed again. Were such legislation enacted into law in West Virginia, PVR's lessees' costs of transportation would increase.

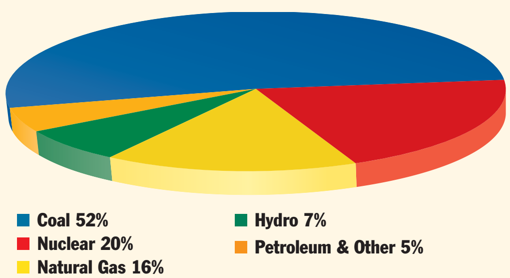
These situations have not yet significantly affected PVR; however, in the long term meaningful growth in West Virginia, where approximately 50 percent of PVR's reserves are located, will require a resolution of these issues.

The coal land management business almost invariably involves exposure to the timber business. PVR sells cutting rights to various contractors. Often timber is cut in advance of a mining project. Ideally, the timber is cut at the same rate it grows, maintaining a sustainable yield. To date, PVR has not entered the timber business as a stand-alone investment; however, the possibility is being thoroughly evaluated.

Timber revenues in 2001 were $1.7 million, which is lower than the $2.4 million recorded in 2000. The drop-off resulted from much lower timber prices, which were extremely high in 2000. Current forecasts for 2002 do not include timber price increases and PVR will sell only what timber is necessary to accommodate its lessees' mining operations.

PVR also invests in coal-related infrastructure. The investments to date have been in projects that directly aid the mining companies on PVR property. For example, the Shober loadout facility, opened in 1999, lowered shipping costs thus making PVR coal more competitive. Modular preparation plants save operators the expense of shipping raw coal long distances to be cleaned, thereby allowing marginal reserves to be mined economically. As part of its growth strategy, the Partnership will begin looking at stand-alone infrastructure projects.

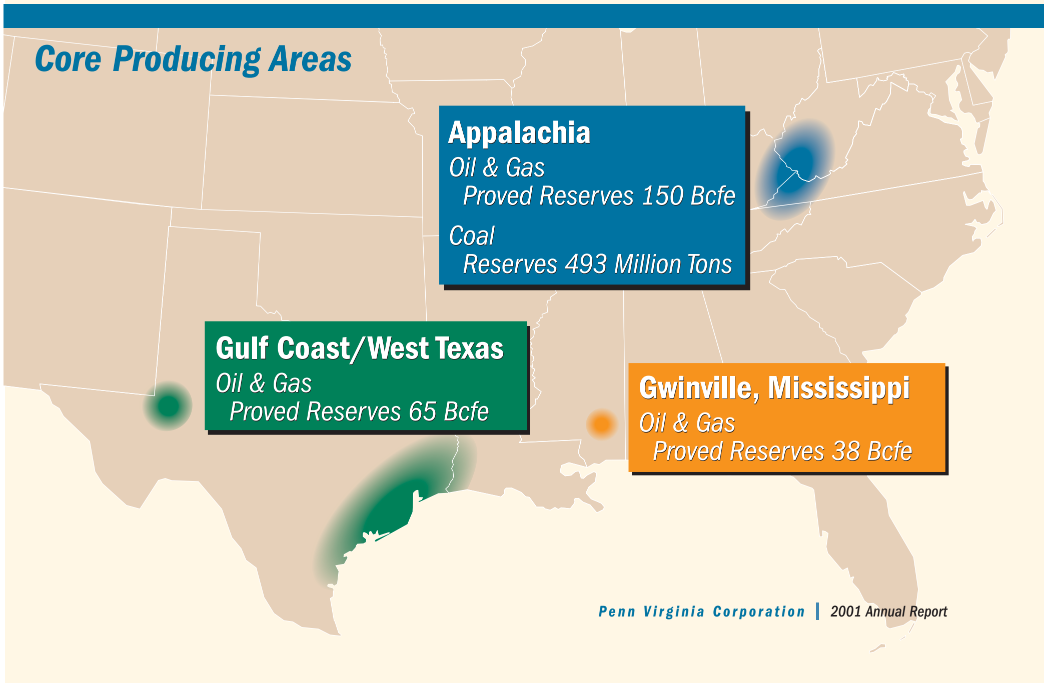
Approximate Electricity Generation by Fuel Source in 2001



Source: U.S. Department of Energy

With almost 70% of electricity generation fueled by natural gas and coal, PVA is well positioned for stability and continued growth.

Core Producing Areas



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the Fiscal Year Ended December 31, 2001

or

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

Commission File Number 0-753

PENN VIRGINIA CORPORATION

One Radnor Corporate Center, Suite 200
100 Matsonford Road
Radnor, PA 19087

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

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

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, $6.25 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 __X__ 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. __X__

The aggregate market value of the voting stock held by non-affiliates of the Corporation at March 8, 2002 was $342,140,045, based on the closing price of $38.40 per share. As of that date, 8,909,897 shares of common stock were issued and outstanding. The number of shareholders of record of the registrant was 707 as of March 8, 2002.

DOCUMENTS INCORPORATED BY REFERENCE:

	Part Into Which Incorporated
(1) Proxy Statement for Annual Shareholders Meeting on May 7, 2002	Part III

Penn Virginia Corporation and Subsidiaries

Part I

Part II

Part III

Part IV

Item 1 | Business

General

Penn Virginia Corporation ("Penn Virginia" or the "Company") is a Virginia corporation founded in 1882. We are engaged in the exploration, development and production of oil and natural gas in the eastern and Gulf Coast onshore areas of the United States. At December 31, 2001, we had proved reserves of approximately 3.9 million barrels of oil and condensate and 229 billion cubic feet (Bcf) of natural gas. We also collect royalties and overriding royalty interests on various oil and gas properties.

Until October 30, 2001, we were also engaged directly in the leasing and management of coal properties in the Central Appalachian region of the United States. In September 2001, we transferred our coal properties and related assets to Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"), a newly formed Delaware limited partnership. The Partnership completed its initial public offering ("IPO") of approximately 7.5 million common units at $21.00 per unit on October 30, 2001. At December 31, 2001 the Partnership owned approximately 493 million tons of proven and probable coal reserves, including approximately 53 million tons of such reserves that were acquired in May 2001 for approximately $33 million. The Partnership's reserves are generally high quality, low-sulfur bituminous coal and are leased to various operators. At December 31, 2001 the Partnership also owned approximately 174 million board feet of timber. Our wholly owned subsidiary, Penn Virginia Resource GP, LLC, a Delaware limited liability company, serves as general partner of the Partnership. After the IPO, we own approximately 52 percent of the Partnership, consisting of a two percent general partner interest, 49 percent subordinated units, and one percent common units. Accordingly, our revenues related to the coal royalty and land management business are now directly dependent on the Partnership's payment of quarterly distributions and incentive distributions, which, in turn, are dependent on the ability of the Partnership's lessees to produce coal. See "Risks Associated with Business Activities – Coal Royalty and Land Management."

Financial Information

We operate in two primary business segments: (1) oil and natural gas and (2) coal royalty and land management through our interests in PVR. 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 18 (Segment Information) of the Notes to the Consolidated Financial Statements for financial information concerning our business segments.

Oil and Gas Operations

Overview

Our oil and gas properties are located primarily in the eastern and Gulf Coast onshore areas of the United States. At December 31, 2001, we had 253 Bcfe of proved reserves (229 Bcf of natural gas) including 206 Bcfe of working interests and 47 Bcfe of royalty interests. During 2001, we acquired Synergy Oil & Gas, Inc., a privately owned oil and gas company, with operations onshore in the Texas Gulf Coast, for $112 million. We added 59 Bcfe of proved reserves in Texas with the acquisition, along with 27,300 net developed and 10,000 net undeveloped leasehold acres and 214 square miles of 3-D seismic data.

Oil and Gas Production

During 2001, 164,000 barrels of oil and condensate and 13,130 MMcf of natural gas, net to our interest, were produced compared with 31,000 barrels and 11,645 MMcf in 2000. We received average prices of $22.94 and $26.84 per barrel and $4.06 and $3.95 per Mcf for oil and gas sales in 2001 and 2000, respectively.

Exploration and Development

We drilled 154 gross (119.1 net) wells in 2001, of which 130 gross (101.1 net) were development and 24 gross (18.0 net) were exploratory. A total of five gross (3.5 net) exploratory wells were non-productive.

Transportation

The majority of our natural gas production is transported to market primarily on three major transmission systems. Nisource, Inc., Dominion Energy, Inc. and Duke Energy, Inc. transported 26 percent, 26 percent and 20 percent, respectively, of our 2001 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 the interconnects with the transmission pipelines. For additional information, see "Risks Associated with Business Activities – Oil and Gas – Transportation."

Marketing and Hedging

We generally sell our natural gas using the spot market and short-term fixed price physical contracts. 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 prices. Recent hedging activity has primarily utilized costless collars and fixed price contracts. Gains and losses from hedging activities are included in revenues when the hedged production occurs. We recognized a gain of $1.9 million on hedging activities in 2001, no gain or loss in 2000, and a loss of $0.4 million in 1999. Beginning January 1, 2001 we account for our derivative activities in accordance with Statement of Financial Accounting Standards ("SFAS")

No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS 137 and SFAS 138.

In 2001, we hedged approximately 27 percent of our natural gas production at an average floor price of $2.92 per MMbtu and a ceiling price of $4.64 per MMbtu. For 2002, we have hedged approximately 41 percent of our anticipated natural gas production at an average floor price of $2.95 per MMbtu and a ceiling price of $3.50 per MMbtu.

For crude oil, we hedged approximately 81 percent of our 2001 crude oil production at an average floor price or $22.53 per barrel and a ceiling price of $28.04 per barrel. In 2002, we have hedged approximately 52 percent of our anticipated crude oil production at an average floor price of $21.31 per barrel and a ceiling price of $25.72 per barrel.

We have in place natural gas hedge positions for 2002 covering approximately 22,682 MMbtu per day. These positions provide average floor and ceiling prices of $2.95 and $3.50 per MMbtu, respectively, and cover approximately 41 percent of anticipated natural gas production.

For 2002, we have hedge positions in place covering approximately 750 barrels per day, or approximately 52 percent of anticipated crude oil production, with average floor and ceiling prices of $21.31 and $25.72 per barrel, respectively.

For 2003, we have a natural gas collar arrangement covering 5,400 MMbtu per day at an average floor price of $2.75 per MMbtu and a ceiling price of $4.48 per MMbtu.

Coal Royalty and Land Management Operations

Overview

At December 31, 2001, the Partnership owned approximately 218,000 acres of coal and timber-bearing land in central Appalachia containing approximately 493 million tons of coal reserves. The Partnership earns coal royalty revenue, based on long-term lease agreements, from 21 coal-mining operators actively mining under 41 separate leases. Coal royalty revenue is based 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 payments. The Partnership does not operate coal mines. The Partnership provides fee-based coal preparation and transportation facilities to some of its lessees to enhance their production levels and generate additional coal service revenue.

The Partnership's timber assets consist of various hardwoods, primarily red oak, white oak, yellow poplar and black cherry. The Partnership owned approximately 174 million board feet of standing saw timber at December 31, 2001. The Partnership's timber inventory only includes timber that can be harvested and is greater than 12 inches in diameter.

Coal Production

The Partnership's lessees mined approximately 15.3 million tons of coal in 2001 and paid an average royalty of $2.11 per ton, compared with approximately 12.5 million tons mined in 2000 at an average royalty of $1.94 per ton.

Timber Production

The Partnership sold approximately 8.7 MMbf in 2001 for an average price of $168 per Mbf, compared with 8.5 MMbf at an average price of $257 per Mbf in 2000. Timber is harvested in advance of lessee mining to prevent loss of the resource. Timber is sold in competitive bid sales involving individual parcels and also on a contract basis, whereby PVR pays independent contractors to harvest timber while PVR directly markets the product.

Coal Services

The Partnership generates coal service revenues from fees charged to lessees for the use of coal preparation and transportation facilities. The majority of these fees have been generated by the unit train loadout facility, which was completed in April 1999 at a cost of $5.2 million. This facility accommodates 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 recognized $1.7 million in coal service revenue in 2001 compared with $1.4 million in 2000. Such amounts are reported in other revenues.

Corporate and Other

Investments

During 2001, we sold 3,307,200 shares of Norfolk Southern Corporation (NYSE: NSC) common stock. The shares were sold in open market transactions on the New York Stock Exchange at an average price of $17.39 per share. Our 3,307,200 common shares of Norfolk Southern Corporation generated dividends of $0.2 million in 2001, and $2.6 million in each of 2000 and 1999. We received a quarterly dividend of $0.06 per share in 2001, which was a reduction from the $0.20 per share realized in each of 2000 and 1999. We had no available-for-sale securities at December 31, 2001. The fair value of our equity portfolio at December 31, 2000 was $44.1 million compared with $67.8 million at December 31, 1999. See Note 5 (Investments and Dividend Income) of the Notes to the Consolidated Financial Statements for additional information.

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 having larger technical staffs and 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, generate electricity and market-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

Our oil and gas revenues, profitability and future rate of growth are highly dependent on the prevailing prices for oil and natural gas. The prices of oil and natural gas realized by us are highly volatile and subject to numerous factors generally beyond our control. The price of oil is generally dependent on world supply and demand, while the price we receive for our natural gas is tied to the specific markets in which such gas is sold. Declines in crude oil prices or natural gas prices adversely impact our revenues, profitability and cash flow and could, under certain circumstances, result in an impairment of our oil and natural gas properties. Due to low commodity prices, in the fourth quarter of 2001, such impairment was recognized on oil and natural gas properties located primarily in Texas. The carrying amount of the properties exceeded the estimated undiscounted future cash flows; thus, we adjusted the carrying amount of the respective oil and gas natural properties to their fair value as determined by discounting their estimated future cash flows. As a result, we recognized a non-cash pre-tax charge of $33.6 million ($21.8 million after tax) related to the impairment of oil and gas properties in the fourth quarter of 2001. There were no impairments of oil and gas properties in 2000 or 1999.

Exploratory Drilling

Both development and exploratory drilling involve risks. However, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons than does development drilling. We anticipate the number of exploratory prospects drilled in the short and long-term will increase, compared with historical amounts. Consequently, it is likely that we will experience increased levels of exploration expense in 2002 and beyond.

Transportation

We transport our natural gas to market on various gathering and transmission pipeline systems owned primarily 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 spot market 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. In 2001, Dominion Energy, Inc. gathered and transported approximately 26% of our natural gas, Nisource, Inc. (formerly Columbia Gas Transmission) approximately 26%, Duke Energy, Inc. approximately 20%, with the remainder divided among several pipeline companies in Texas, West Virginia and Louisiana. Production could be adversely affected by shutdowns of the pipelines for maintenance or replacement as pipeline flexibility is 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, including provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells and 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 and 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 natural gas, and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled 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' sales 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 Corporation, 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 recently issued Order No. 637, which, among other things, (i) lifts the cost-based cap on pipeline transportation rates in the capacity release market until September 30, 2002, for releases of pipeline capacity of less than one year, (ii) permits pipelines to charge different maximum cost-based rates for peak and off-peak times, (iii) encourages auctions for pipeline capacity, (iv) requires pipelines to implement imbalance management services, and (v) restricts the ability of pipelines to impose penalties for imbalances, overruns, and non-compliance with operational flow orders. In addition, the FERC recently implemented new regulations governing 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 new pipeline facilities to charge rates based solely on the 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.

Coal Royalty and Land Management

Our revenues related to the coal royalty and land management business are directly dependent on the Partnership's ability to pay minimum quarterly and incentive distributions to us. Although the Partnership intends to make minimum quarterly distributions of $0.50 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, minimum 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 the general partner subsidiary after cash distributions per unit exceed $0.55 in any quarter. See "Certain Relationships and Related Transactions" in our proxy statement which has been incorporated herein by reference. The Partnership's revenues and its ability to make minimum 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 that has led to some of the competitors of the Partnership's lessees having significantly larger financial and operating resources than the Partnership's lessees do. The Partnership's lessees primarily compete with both large and small producers in Appalachia. They 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, 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 in order 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 us, 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. Capital expenditures for environmental matters have not been material to us or the Partnership or its lessees in recent years. 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. Although 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, the Partnership has, with respect to some of its smaller lessees, set up escrow funds for them to deposit anticipated reclamation costs or required 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 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 the Partnership's lessees' coal. 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 adopted more stringent ambient air quality standards for particulate matter and ozone. Particulate matter includes small particles that are emitted during the combustion process. 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. Nitrogen oxides are naturally occurring byproducts of coal combustion that lead to the formation of ozone. 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 effect 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 or by-products of coal combustion, but consideration is now being given to regulating certain hazardous air pollutant components that are found in coal combustion exhaust, including mercury. Like other environmental regulations, these standards and future standards could result in a decreased demand for coal.

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 and equivalent state and local laws, which obligations include reclaiming and restoring 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. To our knowledge, all of the Partnership's lessees are in compliance in all material respects with applicable regulations relating to reclamation.

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.

Mountaintop Removal Litigation. On October 20, 1999, the United States District Court for the Southern District of West Virginia ("District Court") issued an injunction against the West Virginia Division of Environmental Protection ("WVDEP") prohibiting it from issuing permits for the construction of valley fills over both intermittent and perennial stream segments as part of mining operations. Virtually all mining operations (including those of the Partnership's lessees) utilize valley fills to dispose of excess materials mined during coal production. On April 24, 2001, the Fourth Circuit Court of Appeals overruled the District Court, finding that the 11th amendment to the U.S. Constitution barred the suit against WVDEP in federal court. On July 13, 2001, the Fourth Circuit Court of appeals denied the plaintiffs' petition for rehearing. In October 2001, the plaintiffs appealed the Fourth Circuit decision to the U.S. Supreme Court. On January 22, 2002, the U.S. Supreme Court refused to hear the appeal. Accordingly, challenges to WVDEP's enforcement of its mining program cannot be maintained in federal court. However, challenges may be raised in state court against WVDEP or in federal court against the federal Office of Surface Mining ("OSM"), the agency that oversees state regulation of surface mining. If and to the extent state courts rule that the WVDEP is prohibited from issuing permits for the construction of valley fills or federal courts rule that OSM is compelled to impose such a prohibition on WVDEP, the mining operations of the Partnership's lessees could be affected if legislation is not passed which limits the impact of such a ruling.

Legislation of Weight. The West Virginia Legislature considered legislation during its last session that would have significantly increased the scope of powers available to enforce the current weight restrictions on trucks carrying coal. Although no legislation was approved to allow such an increase, the issue remains controversial in West Virginia and similar legislation could be proposed again. Were such legislation enacted into law in West Virginia or were the recent increase in enforcement of the existing weight restrictions to continue, our lessees' costs of transportation would increase. An increase in costs to our lessees could have an adverse effect on our revenues and our lessees' ability to increase production on our leased properties.

Employees

We had 92 employees at December 31, 2001, including 24 employees who directly provide services for PVR through its general partner. We consider our relations with our employees to be good.

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	54	President and Chief Executive Officer
Frank A. Pici	46	Executive Vice President and Chief Financial Officer
Keith D. Horton	48	Executive Vice President
H. Baird Whitehead	51	Executive Vice President
Nancy M. Snyder	48	Vice President, General Counsel and Secretary
Ann N. Horton	43	Vice President and Controller

A. James Dearlove – Mr. Dearlove is the President and Chief Executive Officer of the Company. He has served in various capacities with the Company since 1977, including Vice President, Senior Vice President and, most recently, President since 1994. Mr. Dearlove was elected to the Company's Board of Directors effective

February 6, 1996. He was appointed Chief Executive Officer in May 1996. Mr. Dearlove is the Chief Executive Officer and a Director of Penn Virginia Resource, GP LLC. He also serves as director of the Powell River Project and 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 the Vice President and Chief Financial Officer of Penn Virginia Resource, GP LLC. From 1996 to August 2001, Mr. Pici was Vice President of Finance and Chief Financial Officer of Mariner Energy, Inc., an energy company. Prior to 1996, he served in various capacities with Cabot Oil & Gas Corporation, including Director, Internal Audit from 1992 to 1994 and Corporate Controller from 1994 to 1996.

Keith D. Horton – Mr. Horton serves as President, Chief Operating Officer and a Director of Penn Virginia Resource, GP LLC. He has served in various capacities with the Company since 1981 and as an executive officer of the Company since 1996. He was appointed Executive Vice President and elected to the Company's Board of Directors in December 2000. Mr. Horton also serves as a director of the Virginia Mining Association, Powell River Project, Virginia Coal Council and the Central Appalachian Section of the Society of Mining Engineers.

H. Baird Whitehead – Mr. Whitehead is an Executive Vice President of the Company, which he joined in January 2001. He also serves as President of the Company's oil and gas subsidiary. He was previously employed for 20 years at Cabot Oil & Gas Corporation in various management positions, most recently as Senior Vice President.

Nancy M. Snyder – Ms. Snyder has served as General Counsel and Corporate Secretary since joining the Company in 1997. She was appointed a Vice President of the Company in December 2000. Ms. Snyder is Vice President, General Counsel and a Director of Penn Virginia Resource, GP LLC. Previously, Ms. Snyder was in private and firm practices in the areas of general corporate and securities law.

Ann N. Horton – Mrs. Horton has served as Principal Accounting Officer and Controller of the Company since 1995. She was appointed a Vice President of the Company in December 2000. She has served in various capacities with the Company and its subsidiaries since 1981.

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

Bbl –	means a standard barrel of 42 U.S. gallons liquid volume
Bcf –	means one billion cubic feet
Bcfe –	means 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
Gross –	acre or well means an acre or well in which a working interest is owned
Mbbl –	means one thousand barrels
Mbf –	means one thousand board feet
Mcf –	means one thousand cubic feet
MMbbl –	means one million barrels
MMbf –	means one million board feet
MMbtu –	means one million British thermal units
MMcf –	means one million cubic feet
Net –	acres or wells is determined by multiplying the gross acres or wells by the owned working interest in those gross acres or wells
NYMEX –	New York Mercantile Exchange
Present value of reserves –	means 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)
Proved Reserves –	means 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
Standardized Measure –	means such amount further reduced by the present value (discounted at 10%) of estimated future income taxes on cash flows
Working Interest –	means a cost-bearing interest under an oil and gas lease that gives the holder the right to produce and develop 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. 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 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 natural 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 affect the value of such properties.

Of the 191,000 acres of coal and timber bearing land, PVR owns 68 percent in fee and 32 percent in mineral. Additionally, PVR leases approximately 27,000 acres of coal and timber bearing land from third parties.

Oil and Gas

Production and Pricing

The following table sets forth production, sales prices and production costs with respect to our properties for the years ended December 31, 2001, 2000 and 1999.

	2001	2000	1999
Production			
Oil and condensate (Mbbls)	164	31	32
Natural gas (MMcf)	13,130	11,645	8,679
Total production (MMcfe)	14,114	11,831	8,871
Average sales price			
Oil and condensate ($/Bbl)	$ 22.94	$ 26.84	$ 14.47
Natural gas ($/Mcf)	4.06	3.95	2.46
Production cost			
Lease operating expense per Mcfe	$ 0.40	$ 0.38	$ 0.46
Lease production taxes per Mcfe	0.31	0.24	0.25
Total production cost per Mcfe	$ 0.71	$ 0.62	$ 0.71
Hedging Summary			
Natural gas prices ($/Mcf):			
Actual price received for production	$ 3.92	$ 3.95	$ 2.50
Effect of derivative hedging activities	0.14	–	(0.04)
Average realized price	$ 4.06	$ 3.95	$ 2.46

Proved Reserves

We had proved reserves of 229 Bcf of natural gas and 3.9 million barrels of crude oil and condensate at December 31, 2001. The present value of the estimated future cash flows discounted at 10 percent (Pre-tax SEC PV10 Value) at December 31, 2001 was $242 million. At December 31, 2001, we had 172 gross (93 net) proved undeveloped drilling locations.

	Oil and Condensate (MMbbls)	Natural Gas (Bcf)	Natural Gas Equivalents (Bcfe)	Pre-tax SEC PV10 Value ($MM)	Year-end Weighted Average Prices Used $/Bbl	$/Mcf
2001						
Developed	**2.2**	**183**	**196**	**$202**		
Undeveloped	**1.7**	**46**	**56**	**40**		
Total	**3.9**	**229**	**252**	**$242**	**$20.40**	**$2.65**
2000						
Developed	0.1	146	147	$540		
Undeveloped	–	28	28	104		
Total	0.1	174	175	$644	$23.31	$9.91
1999						
Developed	0.3	138	140	$116		
Undeveloped	0.1	47	47	20		
Total	0.4	185	187	$136	$21.78	$2.69

The standardized measure of discounted future net cash flows, which represents the present value of future net revenues after income taxes discounted at ten percent, was $189 million, $467 million and $119 million at December 31, 2001, 2000 and 1999, respectively. The year-end weighted average prices used to determine proved reserves at December 31, 2001, 2000 and 1999 were ($/Bbl) $20.40, $23.31, and $21.78, respectively, for oil and condensate and ($/Mcf) $ 2.65, $9.91 and $2.69, respectively, for natural gas. For information on the changes in standardized measure of discounted future net cash flows, see "Note 20. Supplementary Information on Oil and Gas Producing Activities (Unaudited)" in "Item 8 – Financial Statements and Supplementary Data."

In accordance with the Securities and Exchange Commission'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 at the date of such estimates. 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. Net proved oil and gas reserves for the three years ended December 31, 2001 were estimated by Wright and Company, Inc. Prices for oil and gas are subject to substantial seasonal fluctuations and prices for each are subject to substantial fluctuations as a result of 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 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 oil and natural gas that are ultimately recovered, production and operating costs, the amount of timing of future development expenditures and future oil and natural gas sales prices may all differ from those assumed in these estimates. Therefore, the Pre-tax SEC PV10 value amounts shown above should not 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, 2001. The acreage is located in the eastern and southern portions of the United States.

(in thousands)	Gross Acreage	Net Acreage
Developed	656	528
Undeveloped	249	122
Total	905	650

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 means 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.

	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	125	96.1	99	75.3	61	38.1
Non-productive	5	5.0	1	0.9	2	2.0
	130	101.1	100	76.2	63	40.1
Exploratory						
Productive	19	14.5	1	0.2	16	9.2
Non-productive	5	3.5	5	1.3	3	1.5
Under evaluation	–	–	3	1.4	–	–
	24	18.0	9	2.9	19	10.7
Total	154	119.1	109	79.1	82	50.8

Productive Wells

The number of productive oil and gas wells in which we had a working interest at December 31, 2001 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
Natural gas	687	653	386	55	1,073	708

In addition to the above working interest wells, Penn Virginia owns royalty interests in 2,183 gross wells.

Coal Royalty and Land Management

Effective September 14, 2001, we transferred our coal properties and related assets to Penn Virginia Resource Partners, L.P. (NYSE: PVR). An initial public offering of 6.5 million common units at $21.00 per unit was completed and the units began trading on the New York Stock Exchange on October 31, 2001. Including the exercise of an over-allotment option granted to the underwriters of the IPO, 7.475 million common units were sold to the public. After the sale of the common units, we own approximately 52 percent of PVR, consisting of 49 percent subordinated units, a 2 percent general partner interest, and 1 percent of the common units.

The Partnership's coal reserves and timber assets at December 31, 2001 covered 218,000 acres, including fee and leased acreage, in central Appalachia. The coal reserves are in various surface and underground seams.

The Partnership's proven and probable coal reserves are estimated at 492.8 million tons as of December 31, 2001. Reserves are coal tons that can be economically extracted or produced at the time of determination considering legal, economic and technical limitations.

Proven reserves are reserves for which: (a) quantity is computed from dimensions revealed in outcrops, trenches, working 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, and depth and mineral content of reserves are well-established. Probable 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 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.

In areas where geologic conditions indicate potential inconsistencies related to coal reserves, we perform additional drilling 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 steam or metallurgical markets.

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 Partnership's timber assets consist of various hardwoods, primarily red oak, white oak, yellow poplar and black cherry. At December 31, 2001, the Partnership owned an estimated 174 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 2001.

Part II

Item 5 | Market for the Company's Common Stock and Related Stockholder Matters

Common Stock Market Prices And Dividends

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

	2001			2000		
	Sales Price		**Cash Dividends**	Sales Price		Cash Dividends
	High	**Low**	**Paid**	High	Low	Paid
Quarter Ended:						
March 31	**$ 37.39**	**$ 30.00**	**$ 0.225**	$ 18.12	$ 15.81	$ 0.225
June 30	**$ 45.10**	**$ 31.10**	**$ 0.225**	$ 26.88	$ 16.38	$ 0.225
September 30	**$ 38.41**	**$ 27.15**	**$ 0.225**	$ 28.94	$ 21.50	$ 0.225
December 31	**$ 38.50**	**$ 27.90**	**$ 0.225**	$ 33.19	$ 25.56	$ 0.225

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

(in thousands except share data)	Year Ended December 31, **2001**	2000	1999	1998	1997
Revenues[(a)]	**$ 96,571**	$ 105,998	$ 47,697	$ 38,324	$ 41,404
Operating income[(a,b)]	**$ 1,180**	$ 65,636	$ 20,715	$ 10,273	$ 18,728
Net income[(c)]	**$ 34,337**	$ 39,265	$ 14,504	$ 9,591	$ 16,018
Per Common share:					
Net income, basic	**$ 3.92**	$ 4.76	$ 1.73	$ 1.15	$ 1.93
Net income, diluted	**$ 3.86**	$ 4.69	$ 1.71	$ 1.13	$ 1.88
Dividends paid	**$ 0.90**	$ 0.90	$ 0.90	$ 0.90	$ 0.90
Weighted average shares outstanding, basic	**8,770**	8,241	8,406	8,310	8,302
Weighted average shares outstanding, diluted	**8,896**	8,371	8,480	8,463	8,500
Total assets[(e)]	**$ 460,171**	$ 268,766	$ 274,011	$ 256,931	$ 247,230
Long-term debt[(d)]	**$ 46,887**	$ 47,500	$ 78,475	$ 37,967	$ 31,903
Shareholders' equity	**$ 185,454**	$ 171,162	$ 154,343	$ 170,259	$ 163,704

(a) Certain reclassifications have been made to conform to the current year presentation.
(b) Operating income in 2001 included a $33.6 million impairment on oil and gas properties. 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) Includes $43.4 million of long-term debt of PVR that is secured by $43.4 million of U.S. Treasuries also held by PVR.
(e) Total assets reflect the $112 million purchase of Synergy Oil & Gas, Inc. in July 2001.

Summarized Quarterly Financial Data

Quarterly financial data for 2001 and 2000 were as follows:

(in thousands, except share data)	2001 Quarters Ended Mar. 31	June 30[a]	Sept. 30	Dec. 31[b]	2000 Quarters Ended Mar. 31	June 30	Sept. 30	Dec. 31[c]
Revenues[d]	$ 27,121	$ 24,741	$ 24,031	$ 20,678	$ 16,574	$ 19,277	$ 21,359	$ 48,788
Operating Income (loss)	16,935	13,362	6,753	(35,870)	8,273	10,223	11,454	35,686
Net income	$ 10,710	$ 43,018	$ 4,247	$ (23,638)	$ 5,343	$ 6,182	$ 7,202	$ 20,538
Net income per share[e]								
Basic	$ 1.25	$ 4.88	$ 0.48	$ (2.66)	$ 0.65	$ 0.75	$ 0.88	$ 2.46
Diluted	$ 1.22	$ 4.79	$ 0.47	$ (2.63)	$ 0.65	$ 0.74	$ 0.85	$ 2.38
Weighted average shares outstanding:								
Basic	8,549	8,820	8,869	8,890	8,222	8,193	8,213	8,353
Diluted	8,755	8,982	9,007	8,989	8,222	8,325	8,473	8,622

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.

(a) Net income for the second quarter of 2001 included a $54.7 million ($35.6 million after tax) gain on the sale of Norfolk Southern Corporation Common Stock.

(b) Operating loss for the fourth quarter of 2001 included a $33.6 million impairment on oil and gas properties.

(c) Net income for fourth quarter of 2000 included a $23.9 million ($14.2 million after tax) gain on the sale of certain oil and gas properties.

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

(e) 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.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Overview

Our net income for 2001 was $34.3 million or $3.86 per share (diluted) with operating income of $1.2 million and revenues of $96.6 million. The comparable 2000 results were net income of $39.3 million or $4.69 per share (diluted), operating income of $65.6 million and revenues of $106 million. The results for 2001 reflect the sale of our 3.3 million common share position in Norfolk Southern Corporation and other stocks that were classified as available for sale. Excluding the $54.7 million ($35.5 million after tax) gain on the sale, a net loss of $1.2 million would have been recognized for 2001, a 103 percent decrease from 2000. The 2001 decreases were a direct result of impairments of oil and gas properties of $33.6 million ($21.8 million after tax) and the absence of significant gain on sale of properties. In 2000, we recognized a gain of $23.9 million ($14.2 million after tax) on the sale of non-strategic natural gas properties located primarily in Kentucky and West Virginia. These decreases were offset by a slight increase in the average sales price we received for our natural gas production and an increase in production attributable to the acquisition of certain oil and natural gas properties in the Gulf Coast as well as higher levels of coal royalties.

Management is committed to expanding our oil and natural gas operations over the next several years through a combination of exploitation and exploration of existing properties and acquisition of new properties. Historically, we have focused most of our operations in the eastern United States and particularly in Appalachia. However, we believe continued growth opportunities, especially in oil and natural gas, will be enhanced by a presence outside the Appalachian Basin. In keeping with that strategy, we acquired Synergy Oil & Gas, Inc., an oil and natural gas company in the Gulf Coast area with proved reserves of 59.4 Bcfe in July 2001 for $112 million. At December 31, 2001, the Synergy properties had proved reserves of approximately 65.4 Bcfe. In addition, we have significant undrilled acreage that we intend to evaluate for drilling potential. We continued our ambitious drilling program in 2001 by drilling a record 154 gross (119.1 net) wells. In 2001, we produced a record 14.1 Bcfe of oil and natural gas, which was a 19 percent increase over 2000. We fund our drilling and acquisitions with a combination of cash flow from operations and our revolving credit facility. The credit facility has a borrowing base of $140 million and had borrowings of $3.5 million outstanding as of December 31, 2001. We also have a $5 million line working capital line of credit with a financial institution.

In September 2001, we transferred our coal properties and related assets to Penn Virginia Resource Partners, L.P. (NYSE: PVR). An initial public offering of 6.5 million common units at $21.00 per unit was completed and the units began trading on the New York Stock Exchange on October 31, 2001. Including the exercise of an over-allotment option granted to the underwriters of the IPO, 7.5 million common units were sold to the public. After the sale of the common units, we own approximately 52 percent of PVR, consisting of 49 percent subordinated units, a 2 percent general partner interest, and 1 percent of common units. For financial statement purposes, the assets, liabilities and earnings of PVR are included in our consolidated financial statements, with the public unitholders' interest reflected as a minority interest. The Partnership has a $50 million credit facility which was undrawn as of December 31, 2001 and a term loan outstanding in the amount of $43.4 million as of December 31, 2001. The loan is secured by U.S. Treasury Notes owned by the Partnership.

The coal and land management segment reported record revenues of $37.5 million for 2001, an increase of 24 percent over the prior year. This increase was attributable to acquisitions, enhanced production from lessees and the commencement of operations on new mines.

In June 2001, we purchased mineral rights to approximately 53 million tons of high quality coal reserves for $33 million. These assets were among the assets transferred to PVR. The acquisition consisted of approximately 28,000 acres located in Boone, Kanawha and Lincoln Counties, West Virginia.

Results of Operations

Consolidated Net Income

Our 2001 net income was $34.3 million, compared with $39.3 million in 2000 and $14.5 million in 1999. Revenues for 2001 were $96.6 million, compared with $106.0 million and $47.7 in 2000 and 1999, respectively.

In 2001, we sold our 3.3 million common shares in Norfolk Southern Corporation and other stocks classified as available for sale. We recorded a pre-tax gain on the stock sale transactions of approximately $54.7 million. This gain was offset in part by an impairment of oil and gas properties of $33.6 million and an increase in expenses associated with the acquisition of the Synergy properties.

In 2000, we recorded a gain of $23.9 million on the sale of non-strategic natural gas properties located in Kentucky and West Virginia. This sale coupled with an increase in natural gas production and coal royalty tonnage resulted in an increase in net income of $24.8 million or 171 percent compared with 1999.

Selected Financial Data

(in millions, except share data)	**2001**	2000	1999
Revenues	**$ 96.6**	$ 106.0	$ 47.7
Operating costs and expenses	**95.4**	40.4	27.0
Operating income	**1.2**	65.6	20.7
Net income	**34.3**	39.3	14.5
Earnings per share, basic	**3.92**	4.76	1.73
Earnings per share, diluted	**3.86**	4.69	1.71

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

Oil and Gas Segment

The oil and gas segment explores for, develops and produces crude oil and natural gas in the eastern and Gulf Coast onshore portions of the United States.

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, to drill and equip development wells including development dry holes, and to drill and equip exploratory wells that find proved reserves are capitalized. Capitalized costs of producing oil and gas fields are amortized using the units-of-production method based on estimates of proved oil and gas reserves on a field-by-field basis. Oil and gas reserve quantities represent estimates only and there are numerous uncertainties inherent in the estimation process. Actual future production may be materially different from amounts estimated and such differences could materially affect future amortization of proved properties. Estimated costs (net of salvage value) of plugging and abandoning oil and gas wells are reported as additional depreciation and depletion expense using the units-of-production method.

The costs of unproved leaseholds are capitalized pending the results of exploration efforts. 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. Exploratory costs including exploratory dry holes, annual delay rental and geological and geophysical costs are charged to expense when incurred.

Oil and natural gas revenues are generally recorded using the entitlement method in which we recognize our ownership interest in the production as revenue. Each working interest owner in a well generally has the right to a specific percentage of production, although actual production sold may differ from an ownership percentage. Using entitlement accounting, a receivable is recorded when under-production occurs and deferred revenue is recognized when over-production occurs.

We review our long-lived assets to be held and used, including proved oil and natural gas 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 expected future net cash flows from proved reserves, utilizing a risk-adjusted rate of return.

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. Another factor in our future profitability and growth are the results of our exploration and development drilling programs.

Selected Financial and Operating Data

(in thousands, except as noted)	2001	2000	1999
Revenues			
Oil and condensate	$ 3,762	$ 832	$ 463
Natural gas	53,263	46,019	21,384
Gain on sale of properties	460	23,897	–
Other	293	656	1,095
Total Revenues	57,778	71,404	22,942
Expenses			
Lease operating expenses	5,631	4,562	4,090
Exploration expenses	11,514	5,080	1,699
Taxes other than income	4,439	2,809	2,165
General and administrative	5,330	2,656	2,148
Operating expenses before non-cash charges	26,914	15,107	10,102
Depreciation, depletion and amortization	16,418	9,883	6,951
Impairment of properties	33,583	–	–
Total Operating Expenses	76,915	24,990	17,053
Operating Income	$ (19,137)	$ 46,414	$ 5,889
Production			
Oil and condensate (Mbbls)	164	31	32
Natural gas (MMcf)	13,130	11,645	8,679
Total production (MMcfe)	14,114	11,831	8,871
Prices			
Oil and condensate ($/Bbl)	$ 22.94	$ 26.84	14.47
Natural gas ($/Mcf)	4.06	3.95	2.46
Production cost			
Operating cost per Mcfe	$ 0.40	$ 0.38	0.46
Production taxes per Mcfe	0.31	0.24	0.25
Total production cost per Mcfe	$ 0.71	$ 0.62	$ 0.71
Hedging summary			
Natural gas prices ($/Mcf):			
Actual price received for production	$ 3.92	3.95	$ 2.50
Effect of derivative hedging activities	0.14	–	(0.04)
Average price	$ 4.06	$ 3.95	$ 2.46

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues. Oil and gas revenues increased by $10.2 million or 22 percent to $57.0 million in 2001 from 2000. The increase was primarily due to a 19 percent increase in crude oil and natural gas production mainly related to the Synergy acquisition and to increased production from the Gwinville Field, offset in part by production lost from properties disposed of in the fourth quarter of 2000. Approximately 93 percent of our 2001 production was natural gas. The average natural gas price received during 2001 was $4.06 per Mcf compared with $3.95 per Mcf in 2000, a three percent increase. The average oil price received was $22.94 per barrel for 2001, down 15 percent from $26.84 per barrel in 2000.

Natural gas prices were extremely volatile in 2001. From time to time, we hedge the price received for market-sensitive production through the use of swaps and costless collars. Gains and losses from hedging activities are included in natural gas revenues when the hedged production occurs. We recognized a gain of $1.9 million in 2001 on hedging activities with no gain or loss recognized in 2000.

Operating expenses. Production costs, consisting of lease operating expense and taxes other than income, increased from $7.4 million in 2000 to $10.0 million in 2001. Production costs increased from $0.62 per Mcfe in 2000 to $0.71 per Mcfe in 2001. The increase was primarily attributable to the third quarter 2001 Synergy acquisition.

Exploration expenses increased from $5.1 million in 2000 to $11.5 million in 2001. The $11.5 million in 2001 consisted of $2.4 million in seismic expenditures, charges relating to five gross (3.5 net) nonproductive, exploratory wells and the impairment of unproved leasehold costs. Our increased seismic expenditures for the year, compared with $1.7 million in 2000, represented a continued effort to establish a balanced exploratory program.

General and administrative ("G&A") expenses increased to $5.3 million in 2001 from $2.7 million in 2000. The increase was attributable to the Synergy acquisition and related personnel expenses.

Oil and gas depreciation, depletion and amortization increased to $16.4 million in 2000 from $9.9 million in 2000. This variance was primarily due to increased production and a higher cost basis in the producing assets. The Synergy acquisition was completed when crude oil and natural gas future prices were higher than forecasted prices at year-end 2001. As a result of low commodity prices in the fourth quarter 2001, we subjected all properties to impairment testing and recognized a pretax impairment charge related primarily to our Texas properties of $33.6 million ($21.8 million after tax). The impairment charge will result in lower depreciation, depletion and amortization charges in future periods.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Revenues. Oil and gas revenues increased $25.0 million to $46.8 million in 2000 from 1999 primarily due to an increase in natural gas production.

Natural gas sales increased 115 percent to a record $46.0 million due to a 34 percent increase in production coupled with a 61 percent increase in the average price received per Mcf. Our $34.7 million acquisition of mineral interests in May 2000 represents 1,111 MMcf of the 2,966 MMcf increase in natural gas production. The development of our $13.7 million acquisition in July 1999 accounted for 1,511 of the increase with the remainder attributable to drilling success in Appalachia.

Natural gas prices were extremely volatile in 2000. In April and May of 2000, we entered into several physical contracts that totaled 9,289 MMcf per day for the remainder of 2000. The volumes under contract accounted for 20 percent of our 2000 production at a price of $3.39 per Mcf. We had one contract remaining that expires in March 2001 covering 18 percent of anticipated first quarter production at $3.12 per Mcf.

Gains and losses from hedging activities are included in natural gas revenues when the hedged production occurs. We recognized a loss of $0.4 million in 1999 on hedging activities with no gain or loss recognized in 2000.

Gain on the sale of properties includes $23.9 million ($14.2 million after tax) related to the sale of mature oil and gas properties located primarily in Kentucky and West Virginia. Proceeds from the December 2000 sale totaled $54.3 million, after closing adjustments.

Operating expenses. Production costs, consisting of lease operating expense and taxes other than income, increased from $6.3 million in 1999 to $7.4 million in 2000. Production costs decreased from $0.71 per Mcfe in 1999 to $0.62 per Mcfe in 2000. A decrease, on a Mcfe basis, of $0.06 resulted from our May 2000 acquisition of royalty interest for $34.7 million. The remainder of the decrease is attributable to the low operating costs associated with the increased production from our 1999 acquired properties in Mississippi. These decreases, on a Mcfe basis, were offset by an increase in severance taxes related to increased average prices received in 2000.

Exploration expenses increased from $1.7 million in 1999 to $5.1 million in 2000. The $5.1 million in 2000 consists of $1.7 million in seismic expenditures, charges relating to five gross (1.3 net) nonproductive, exploratory wells and unproved leasehold costs. Our increased seismic expenditures for the year, compared with $0.3 million in 1999, represents a continued effort to establish a balanced exploratory program.

General and administrative ("G&A") expenses increased to $2.7 million in 2000 from $2.1 million in 1999; however, G&A expenses decreased to $0.22 per Mcfe in 2000 from $0.24 Mcfe in 1999. The decrease of $0.02 per Mcfe is attributable to increased production from acquisitions and an accelerated drilling program, offset by additional staffing necessary to accomplish those objectives.

Oil and gas depreciation, depletion and amortization increased to $9.9 million, or $0.84 per Mcfe, in 2000 from $7.0 million, or $0.78 per Mcfe, in 1999. The increase is primarily due to our acquisitions in July 1999 and May 2000.

Coal Royalty and Land Management Segment

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

Coal royalty revenues are recognized on the basis of tons sold by the Partnership's lessees and the corresponding revenue from those sales. Most coal leases are based on minimum monthly or annual payments, a minimum dollar royalty per ton and/or a percentage of the gross sales price. In addition to coal royalty revenues, the Partnership also generates coal service revenues from fees charged to lessees for the use of coal preparation and transportation facilities.

The coal royalty stream is impacted by several factors, which we 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 our lessees or their customers' ability to use coal may require us, our lessees or their customers to change operations significantly or incur substantial costs.

Selected Financial and Operating Data

(in thousands, except as noted)	**2001**	2000	1999
Revenues			
Coal royalties	**$ 32,365**	$ 24,308	$ 17,836
Timber	**1,732**	2,388	1,948
Coal services	**1,660**	1,385	982
Other	**1,756**	2,108	584
Total Revenues	**37,513**	30,189	21,350
Expenses			
Operating costs	**3,812**	3,480	1,382
General and administrative	**5,459**	4,847	4,123
Operating Expenses Before Non-cash Charges	**9,271**	8,327	5,505
Depreciation, depletion and amortization	**3,084**	2,047	1,269
Total Operating Expenses	**12,355**	10,374	6,774
Operating Income	**$ 25,158**	$ 19,815	$ 14,576
Production			
Royalty coal tons produced by lessees (thousands)	**15,306**	12,536	8,603
Timber sales (Mbf)	**8,741**	8,545	9,020
Prices			
Royalty per ton	**$ 2.11**	$ 1.94	$ 2.07
Timber sales price per Mbf	**$ 168**	$ 257	$ 206

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

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues. Coal royalty and land management segment revenues were $37.5 million in 2001 and $30.2 million in 2000, representing a 24 percent increase.

Coal royalties increased $8.1 million from $24.3 million in 2000 to $32.4 million in 2001. Increased production was the primary factor for the royalty increase. Royalty tons increased 2.8 million from 12.5 million in 2000 to 15.3 million in 2001, or 22 percent. These production increases were attributable to the start up of five new mines, the June 2001 acquisition of new properties and the completion of a capital project on another lease.

Timber revenues decreased to $1.7 million for the year ended December 31, 2001 from $2.4 million for the year ended December 31, 2000, a decrease of $0.7 million, or 27 percent. The decrease is primarily attributable to a decrease in the average price received for the timber from $257 per Mbf for the year ended December 31, 2000 to $168 per Mbf for the year ended December 31, 2001. The decrease reflected overall market conditions as well as the sale of lower priced species and lower quality timber.

Coal services revenue increased to $1.7 million for the year ended December 31, 2001 from $1.4 million in 2000, an increase of $0.3 million, or 20 percent. The increase was a direct result of the addition of a small preparation plant put into service during the year and additional usage of our existing coal service facilities.

Other revenues were $1.8 million for the year ended December 31, 2001 compared with $2.1 million for the year ended December 31, 2000, an decrease of $0.3 million, or 17 percent. The decrease was primarily due to gains from the sale of property and equipment in 2000, offset by the recognition of minimum rental payments received from lessees which are no longer recoupable.

Operating expenses. Operating expenses were $3.8 million for the year ended December 31, 2001 compared with $3.5 million for the year ended December 31, 2000, an increase of $0.3 million, or 10 percent. This variance was primarily due to an increase in production by lessees on our subleased properties resulting in royalty expense incurred. Production from subleased properties increased from 2.1 million tons for the year ended December 31, 2000 to 2.3 million tons for the year ended December 31, 2001, an increase of 0.2 million tons, or 10 percent.

General and administrative expenses increased to $5.5 million for the year ended December 31, 2001 compared to $4.8 million for the year ended December 31, 2000. This increase was primarily attributable to fees associated with tax preparation and public reporting by the Partnership.

Depreciation and depletion expense for the year ended December 31, 2001 was $3.1 million compared with $2.0 million for the year ended December 31, 2000, an increase of $1.1 million, or 51 percent. This increase primarily resulted from coal production increases of 22 percent. Depreciation and depletion expense increased, on a per ton basis, to $0.20 per ton for the year ended December 31, 2001 from $0.16 for the year ended December 31, 2000. The $0.04 increase on a per ton basis resulted from increased production from the Coal River property, which has a significantly higher cost basis.

Year ended December 31, 2000 compared to year ended December 31, 1999.

Coal royalty and land management segment revenues were $30.2 million in 2000 compared with $21.4 million in 1999, a 41 percent increase.

Coal royalties increased $6.5 million from $17.8 million in 1999 to $24.3 million in 2000 all on the basis of increased production. Production rose from 8.6 million tons in 1999 to 12.5 million tons in 2000.

Timber revenues increased to $2.4 million for the year ended December 31, 2000 from $1.9 million for the year ended December 31, 1999, an increase of $0.4 million, or 23 percent. The increase was largely attributable to an increase in the average price received for the timber from $206 per Mbf for the year ended December 31, 1999 to $257 per Mbf for the year ended December 31, 2000. The increase in average price received resulted from harvesting higher quality hardwoods during 2000.

Coal services revenue increased to $1.4 million for the year ended December 31, 2000 from $1.0 million in 1999, an increase of $0.4 million, or 41 percent. The increase resulted from the first full year of operations for the unit train loadout facility in 2000 as compared to nine months of operations for 1999.

Other revenues increased to $2.1 million for the year ended December 31, 2000 compared with $0.6 million for the year ended December 31, 1999, an increase of $1.5 million, or 261 percent. That increase was due to a gain on the sale of property and equipment and an increase in minimum rental payments recognized during the first quarter of 2000.

Operating expenses were $3.4 million for the year ended December 31, 2000 compared with $1.4 million for the year ended December 31, 1999, an increase of $2.0 million, or 152 percent.

This increase was due to the September 1999 acquisition of the Coal River property, which resulted in an increase in production by lessees on subleased properties resulting in royalty expense incurred, continuing property maintenance and additional property taxes. Production on subleased properties increased to 2.1 million tons in the year ended December 31, 2000 from 0.5 million tons in the year ended December 31, 1999.

General and administrative expenses were $4.8 million for the year ended December 31, 2000 compared with $4.1 million for the year ended December 31, 1999, an increase of $0.7 million, or 18 percent. Over these same periods, production increased 46 percent primarily due to acquisitions, the first full year of operation of the unit train loadout facility and the commencement of operations from new mines which resulted in additional general and administrative expense.

Depreciation and depletion expense for the year ended December 31, 2000 was $2.0 million compared to $1.3 million for the year ended December 31, 1999, an increase of $0.7 million, or 61 percent. This increase resulted from the first full year of ownership of the properties and facilities included in the September 1999 acquisition. Depreciation and depletion expense increased slightly, on a per ton basis, to $0.16 per ton for the year ended December 31, 1999.

Corporate and Other

Dividends. In April 2001, we sold our 3.3 million common share position in Norfolk Southern Corporation at an average selling price of $17.39 per share. Proceeds, net of commissions totaled approximately $57.4 million. As a result, dividend income decreased from $2.6 million in 2000 to $0.2 million in 2001. In January 2001, Norfolk Southern Corporation reduced its quarterly dividend from $0.20 per share to $0.06 per share.

Reserves

Oil and Gas Reserves

Our total proved reserves at year-end 2001 were 252.8 Bcfe, compared with 174.6 Bcfe at 2000 year-end. The increase was largely attributable to our July 2001 acquisition of Synergy Oil & Gas, Inc. for $112 million ($157.4 million including the impact of deferred income taxes), resulting in a 59.6 Bcfe increase in proved reserves. Proved developed reserves increased 50.0 Bcfe, or 34 percent, to 196.4 Bcfe. At year-end 2001, proved developed reserves comprised 78 percent of our total proved reserves, compared with 84 percent at year-end 2000. We had 93 net proved undeveloped drilling locations at year-end 2001, compared with 74 locations at year-end 2000. We acquired 35.9 Bcfe of proved oil and natural gas reserves, primarily consisting of royalty interests, during 2000 for $36.0 million. In December 2000, the Company received $54.3 million, after closing adjustments, from the sale of mature oil and natural gas properties in Kentucky and West Virginia, which contained 66.6 Bcfe of proved oil and natural gas reserves.

Our comparative reserve replacement measures are as follows:

	2001	2000
Finding and development cost (a), ($/Mcfe)		
Current year	$ 1.41	$ 0.82
Three year weighted average	1.24	1.56
Reserve replacement cost (b), ($/Mcfe)		
Current year	$ 1.26	$ 0.92
Three year weighted average	1.09	1.08
Reserve replacement percentage (c), ($/Mcfe)		
Current year	660%	556%
Three year weighted average	544%	332%

Finding and development cost, reserve replacement cost and reserve replacement percentage are not measures presented in accordance with generally accepted accounting principles ("GAAP") and are not intended to be used in lieu of GAAP presentation. These measures are commonly used by financial statement users as a measurement to determine the performance of a company's oil and gas activities.

(a) Finding and development cost is calculated by dividing 1) costs incurred in certain oil and gas activities less proved property acquisitions, by 2) reserve extensions, discoveries and other additions and revisions. Current year finding and development costs used in this calculation exclude $62.2 million for unproved property acquisition costs (including the impact of deferred income taxes) related to the purchase of Synergy Oil & Gas, Inc. No proved reserves were recorded relative to these unproved property acquisition costs, for which future exploration and development activities will be conducted. Had the Synergy unproved property acquisition costs been included in the finding and development cost calculations, current year and three year weighted average cost per Mcfe would have been $3.26 and $2.66, respectively.

(b) Reserve replacement cost is calculated by dividing 1) costs incurred in certain oil and gas activities, including acquisitions, by 2) reserve purchases, extensions, discoveries and other additions and revisions. Current year reserve replacement costs used in this calculation excludes $62.2 million for unproved property acquisition costs described in footnote (a) above and $27.2 million of deferred income taxes on proved property acquisition costs related to the purchase of Synergy Oil & Gas, Inc. Had the Synergy unproved property acquisition costs and the deferred income taxes on Synergy proved property acquisition costs been included in the reserve replacement cost calculations, current year and three year weighted average cost per Mcfe would have been $2.20 and $1.70, respectively.

(c) 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 492.8 million tons at December 31, 2001. Royalties were collected for 15.3 million tons in 2001. Proven and probable coal reserves means coal that is economically mineable using existing equipment and methods under federal and state laws now in effect.

Market Risk

Interest Rate Risk. The carrying value of our debt approximates fair value. At December 31, 2001, the Company had $3.5 million of long-term debt represented by a secured revolving credit facility (the "Revolver"). The Revolver matures in October 2004 and is governed by a borrowing base calculation that is redetermined semi-annually. The Company has the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.375 to 1.875 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 0.375 to 0.875 percent. As a result, the Company's 2002 interest costs will fluctuate based on short-term interest rates relating to the Revolver. The Partnership had borrowed an additional $43.4 million at December 31, 2001 in the form of a term note. The term loan expires in 2004 and is secured by restricted U.S. Treasury Notes. The Partnership has the option to elect interest at (i) LIBOR plus a Euro-rate margin of 0.5 percent, based on certain financial data or (ii) the greater of the prime rate or federal funds rate plus .05 percent.

Price Risk Management. Our price risk management program permits the utilization of fixed-price contracts and financial instruments (such as futures, forward and option contracts and swaps) to mitigate the price risks associated with fluctuations in natural gas prices as they relate to our anticipated production. These contracts and financial instruments are designated as cash flow hedges and accounted for in accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, as amended by SFAS No. 137 and SFAS No. 138. See Note 7 (Price Risk Management Activities) in the consolidated financial statements of Penn Virginia. 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. As of March 14, 2002 our open commodity price risk management positions on average daily volumes were as follows:

Natural Gas Collar Arrangements

- 11,855 MMbtus at a weighted average floor price of $3.14 per MMbtu and ceiling price of $4.20 per MMbtu through December 2002
- 5,400 MMbtus at a weighted average floor price of $2.75 per MMbtu and ceiling price of $4.48 per MMbtu for 2003

Natural Gas Swap Contracts

- 13,000 MMbtus at a NYMEX price of $2.74 per MMbtu expiring October 2002

Crude Oil Collar Arrangements

- 764 Bbls at a weighted average floor price of $21.31 per Bbl and ceiling price of $25.72 per Bbl through December 2002

Reserve Estimates. There are many uncertainties inherent in estimating proved oil and natural gas 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 natural 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 natural gas reserves are those reserves expected to be recovered through existing equipment and operating methods.

Capital Resources and Liquidity

Our contractual obligations as of December 31, 2001 were as follows:

Contractual Obligations:

(in thousands)	Total	Payments Due by Period 1 Year	2-3 Years	4-5 Years	Thereafter
Penn Virginia revolving credit facility	3,500	$ –	$ 3,500	$ –	$ –
PVR revolving credit facility	–	–	–	–	–
PVR Term loan(1)	43,387	–	43,387	–	–
Line of credit	1,235	1,235	–	–	–
Rental commitments(2)	6,275	1,598	2,674	2,003	–
Total contractual cash obligations	54,397	$ 2,833	$49,561	$ 2,003	$ –

(1) Term loan is secured by U.S. Treasury notes.
(2) Rental commitments primarily relate to equipment, car and building leases.

Cash flows from Operating Activities

Funding for our activities has historically been provided by operating cash flows and bank borrowings. Net cash provided from operating activities was $44.2 million in 2001, compared with $41.7 million in 2000 and $25.1 million in 1999. Our consolidated cash balance increased to $9.6 million in 2001 compared with $0.7 million in 2000 and 1999, respectively.

Cash flows from Investing Activities

We used $179.4 million in investing activities in 2001, compared with $3.3 million in 2000 and $58.7 million in 1999. Capital expenditures, including acquisitions net of non-cash items, totaled $196.0 million, compared with $59.4 million in 2000 and $60.7 million in 1999. Capital expenditures in 2000 were partially offset by proceeds from the sale of certain oil and gas properties totaling $55.2 million after closing adjustments. The following table sets forth capital expenditures, including acquisitions net of non-cash items, made during the periods indicated.

(in thousands)	Year ended December 31, 2001	2000	1999
Oil and gas			
Acquisitions	**$ 118,497**	$ 36,916	$ 16,620
Development	**30,123**	18,317	9,189
Exploration	**11,253**	3,200	2,587
Support equipment and facilities	**1,422**	244	209
Coal royalty and land management			
Lease acquisitions	**32,992**	–	30,094
Support equipment and facilities	**674**	485	1,861
Other	**1,077**	281	91
Total capital expenditures	**$ 196,038**	$ 59,443	$ 60,651

We drilled 96.1 net successful development wells, 14.5 net successful exploratory wells and 8.5 net non-productive wells in 2001, compared with 75.3 net successful development wells, 0.2 net successful exploratory wells and 2.6 net non-productive wells in 2000.

Management is committed to expanding its oil and natural gas operations over the next several years through a combination of exploitation, exploration and acquisition of new properties. In July 2001, we acquired all of the outstanding stock of Synergy Oil & Gas, Inc., a Texas corporation. Cash consideration for the stock was $112 million and was funded by long-term debt. The acquisition provided us with a growth platform in highly prospective South Texas. Proved reserves at December 31, 2001 were 59.6 Bcfe. In addition, the acquisition provided numerous future drilling locations. During 2000, we acquired proved natural gas properties in Appalachia at a cost of $36.0 million, including a $34.7 million acquisition of royalty interests in West Virginia and eastern Kentucky. The properties had proved reserves of 35.9 Bcfe at December 31, 2000 in addition to drilling potential.

Capital expenditures for 2002, before lease and proved property acquisitions, are expected to be $44 to $49 million predominantly for the drilling of exploration and development of wells in the oil and gas segment with approximately $1.0 million allocated to the coal royalty and land management segment. In addition, we plan to invest an additional $5 to $6 million in the acquisition and evaluation of seismic data. We plan to drill approximately 120 to 130 gross (80 to 90 net) wells. We continually review drilling expenditures and may increase, decrease or reallocate amounts based on industry conditions. We believe our cash flow from operations and sources of debt financing are sufficient to fund our 2002 planned capital expenditure program.

On October 30, 2001, we completed an initial public offering (IPO) of 7.475 million common units of Penn Virginia Resource Partners, L.P. (NYSE: PVR), a publicly traded master limited partnership (MLP). We had previously transferred our coal reserves and related assets to PVR and own approximately 52 percent of the MLP. Most of the $142.4 million of net proceeds from the IPO was used to repay outstanding borrowings against the Company's revolving credit facility. In June 2001, we purchased mineral rights to approximately 53 million tons of high quality coal reserves for $33 million in cash.

In September 1999, we completed an acquisition that included over 90 million tons of high quality coal reserves as well as oil and gas leases, timber assets, a short line railroad and a coal loading dock on the Kanawha River in West Virginia. The $30 million acquisition complemented our existing Coal River Properties located on the inland river system in West Virginia. PVR continues to diversify its coal customer base by adding additional lessees and by searching for additional coal reserve acquisition opportunities.

Cash flows from Financing Activities

Net cash provided (used) by financing activities was $144.1 million in 2001, compared with ($38.4) million in 2000 and $34.0 million in 1999.

Penn Virginia has a $150 million secured revolving credit facility (the "Revolver") led by J.P. Morgan Chase Bank, f.k.a. the Chase Manhattan Bank, with a final maturity of October 2004. The credit facility has a borrowing base of $140 million and had borrowings of $3.5 million against the facility as of December 31, 2001. The Revolver contains financial covenants requiring the Company to maintain certain levels of net worth, debt-to-capitalization and dividend limitation restrictions, among other requirements. The outstanding balance on the previous Revolver was $47.5 million and $77.7 million at December 31, 2000 and 1999, respectively. We currently have a $5 million line of credit with a financial institution due in December 2002, renewable annually. We have the option to elect either a fixed rate LIBOR loan, floating rate LIBOR loan or base rate loan.

The Partnership has a $50 million revolving credit facility led by PNC Bank which was undrawn as of December 31, 2001. As part of the credit facility the Partnership had also borrowed an additional $43.4 million in the form of a term loan as of December 31, 2001. The term loan expires in October 2004 and is secured by restricted U.S. Treasury Notes. The Partnership has the option to elect interest at (i) LIBOR plus a Euro-rate margin of 0.5 percent, based on certain financial data or (ii) the greater of the prime rate or federal funds rate plus .05 percent. The financial covenants of the term loan include, but are not limited to, maintaining certain levels of financial leverage, interest coverage and cash flow.

Management believes its sources of funding are sufficient to meet short and long-term liquidity needs not funded by cash flows from operations.

Other

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143 Accounting for Asset Retirement Obligations. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred with the associated asset retirement costs being capitalized as a part of the carrying amount of the long-lived asset. SFAS No. 143 also includes disclosure requirements that provide a description of asset retirement obligations and reconciliation of changes in the components of those obligations. We currently record our plugging and abandoning costs (net of salvage value) with respect to our oil and gas properties as additional depreciation and depletion expense using the units-of-production method. This statement would require us to recognize a liability for the fair value of our plugging and abandoning liability (excluding salvage value) with the associated costs as part of our oil and gas property balance. We are evaluating the future financial reporting effect of adopting SFAS No. 143 and will adopt the standard effective January 1, 2003.

In August 2001, the Financial Accounting Standards Board issued SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets. This Statement supersedes SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, and the accounting and reporting provisions of APB No. 30, Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Ususal and Infrequently Occurring Events and Transactions, for the disposal of segment of a business. SFAS No. 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. We will adopt the provisions of this Statement in the first quarter of 2002. Under present conditions, management does not expect the initial adoption of SFAS 144 to have material effect on the financial position, results of operation or liquidity.

Environmental Matters

Our operating segments are subject to various environmental hazards. Numerous federal, state and local laws, regulations and rules govern the environmental aspects of our business. 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 profitability, capital expenditures, cash flows or competitive position. There is no assurance that 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 leasing of property to coal operators, all environmental and reclamation liabilities are the responsibility of the 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.

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 statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. In addition, Penn Virginia and its representatives may from time to time make other oral or written statements that are also forward-looking statements.

Such forward-looking statements include, among other things, statements regarding development activities, capital expenditures, acquisitions and dispositions, drilling and exploration programs, expected commencement dates of coal mining or oil and gas production, projected quantities of future oil and gas production by Penn Virginia, projected quantities of future coal production by PVR's lessees producing coal from reserves leased from PVR, costs and expenditures as well as projected demand or supply for coal and oil and gas, which will affect sales levels, prices and royalties realized by Penn Virginia.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting Penn Virginia and therefore involve a number of risks and uncertainties. Penn Virginia cautions that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Important factors that could cause the actual results of operations or financial condition of Penn Virginia to differ include, but are not necessarily limited to: the cost of finding and successfully developing oil and gas reserves; the ability to acquire new oil and gas reserves on satisfactory terms; the price for which such reserves can be sold; the volatility of commodity prices for oil and gas; the risks associated with having or not having price risk management programs; Penn Virginia's ability to obtain adequate pipeline transportation capacity for its oil and gas production; competition among producers in the oil and gas industry generally; the extent to which the amount and quality of actual production differs from estimated mineable and merchantable coal reserves and proved oil and gas reserves; unanticipated geological problems; availability of required 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; environmental risks affecting the drilling and producing of oil and gas wells; the timing of receipt of necessary governmental permits; labor relations and costs; accidents; changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions; changes in financial market conditions; and other risk factors detailed in Penn Virginia's Securities and Exchange commission filings. Important factors that could affect the results of operations or financial condition of Penn Virginia Resource Partners, L.P. which, in turn, could cause the actual results of operations or financial condition of Penn Virginia to differ, include, but are not necessarily limited to: the cost of finding new coal reserves; the ability to acquire new coal reserves on satisfactory terms; the price for which such reserves can be sold; the volatility of commodity prices for coal; the risks associated with having or not having price risk management programs; the Partnership's ability to lease new and existing coal reserves; the ability of lessees to produce sufficient quantities of coal on an economic basis from the Partnership's reserves; the ability of lessees to obtain favorable contracts for coal produced from the Partnership's reserves; competition among producers in the coal industry generally and in the Appalachian Basin in particular; the extent to which the amount and quality of actual production differs from estimated mineable and merchantable coal reserves; unanticipated geological problems; availability of required materials and equipment; the occurrence of unusual weather or operating conditions including force majeure or events; the failure of equipment or processes to operate in accordance with specifications or expectations; delays in anticipated start-up dates; environmental risks affecting the mining of coal reserves; the timing of receipt of necessary governmental permits; 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; risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions; the experience and financial condition of lessees of coal reserves, joint venture partners and purchasers of reserves in transactions financed by the Partnership, including their ability to satisfy their royalty, environmental, reclamation and other obligations to the Partnership and others; changes in financial market conditions; and other risk factors detailed in the Partnership's Securities and Exchange commission filings. other risk factors detailed in Penn Virginia's Securities and Exchange commission filings. Many of such factors are beyond Penn Virginia's ability to control or predict. Readers are cautioned not to put undue reliance on forward-looking statements.

While Penn Virginia periodically reassesses material trends and uncertainties affecting Penn Virginia's 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 Penn Virginia's quarterly, annual or other reports filed with the Securities and Exchange Commission, Penn Virginia does not intend to review or update any particular forward-looking statement, whether as a result of new information, future events or otherwise.

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 20, 2001

By: /s/ Frank A. Pici
(Frank A. Pici,
Executive Vice President and Chief Financial Officer)

March 20, 2001

By: /s/ Ann N. Horton
(Ann N. Horton,
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 20, 2002**
/s/ Richard A. Bachmann **(Richard A. Bachmann)**	**Director**	**March 20, 2002**
/s/ Edward B Cloues, II **(Edward B. Cloues, II)**	**Director**	**March 20, 2002**
/s/ A. James Dearlove **(A. James Dearlove)**	**Director and Chief Executive Officer**	**March 20, 2002**
/s/ Keith D. Horton **(Keith D. Horton)**	**Director and Executive Vice President**	**March 20, 2002**
/s/ Peter B. Lilly **(Peter B. Lilly)**	**Director**	**March 20, 2002**
/s/ Marsha R. Perelman **(Marsha R. Perelman)**	**Director**	**March 20, 2002**
/s/ Joe T. Rye **(Joe T. Rye)**	**Director**	**March 20, 2002**

Item 8 | Financial Statements and Supplementary Data

Penn Virginia Corporation and Subsidiaries

Index to Financial Section

Management's Report on Financial Information

Management of Penn Virginia Corporation is responsible for the preparation and integrity of the financial information included in this annual report. The financial statements have been prepared in accordance with generally accepted accounting principles, which involve the use of estimates and judgments where appropriate.

The corporation has a system of internal accounting controls designed to provide reasonable assurance that assets are safeguarded against loss or unauthorized use and to produce the records necessary for the preparation of financial information. The system of internal control is supported by the selection and training of qualified personnel, the delegation of management authority and responsibility, and dissemination of policies and procedures. There are limits inherent in all systems of internal control based on the recognition that the costs of such systems should be related to the benefits to be derived. We believe the corporation's systems provide this appropriate balance.

The corporation's independent public accountants, Arthur Andersen LLP, have developed an understanding of our accounting and financial controls and have conducted such tests as they consider necessary to support their opinion on the financial statements. Their report contains an independent, informed judgment as to the corporation's reported results of operations and financial position.

The Board of Directors pursues its oversight role for the financial statements through the Audit Committee, which consists solely of outside directors. The Audit Committee meets regularly with management, the internal auditor and Arthur Andersen LLP, jointly and separately, to review management's process of implementation and maintenance of internal controls, and auditing and financial reporting matters. The independent and internal auditors have unrestricted access to the Audit Committee.

A. James Dearlove
President and
Chief Executive Officer

Frank A. Pici
Executive Vice President and
Chief Financial Officer

Report of Independent Public Accountants

To the Shareholders of Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation (a Virginia corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Penn Virginia Corporation and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Houston, Texas
February 18, 2002

Penn Virginia Corporation And Subsidiaries
Consolidated Statements Of Income

(in thousands, except share data)	Year Ended December 31, 2001	2000	1999
Revenues			
Oil and condensate	$ 3,762	$ 832	$ 463
Natural gas	53,263	46,019	21,384
Coal royalties	32,365	24,308	17,836
Timber	1,732	2,388	1,948
Dividends	198	2,646	2,646
Gain on the sale of properties	492	24,795	280
Other	4,759	5,010	3,140
	96,571	105,998	47,697
Expenses			
Lease operating expenses	9,284	7,629	4,873
Exploration expenses	11,832	5,660	2,146
Taxes other than income	5,433	3,648	2,795
General and administrative	15,680	11,398	8,775
Impairment of oil and gas properties	33,583	–	–
Depreciation, depletion and amortization	19,579	12,027	8,393
	95,391	40,362	26,982
Operating Income	1,180	65,636	20,715
Other income (expense)			
Gain on the sale of securities	54,688	–	–
Interest expense	(2,070)	(7,878)	(3,298)
Interest income	1,602	1,458	1,354
Other	14	14	63
Income from operations before minority interest and income taxes	55,414	59,230	18,834
Minority interest	1,763	–	–
Income tax expense	19,314	19,965	4,330
Net Income	$ 34,337	$ 39,265	$ 14,504
Net income per share, basic	$ 3.92	$ 4.76	$ 1.73
Net income per share, diluted	$ 3.86	$ 4.69	$ 1.71
Weighted average shares outstanding, basic	8,770	8,241	8,406
Weighted average shares outstanding, diluted	8,896	8,371	8,480

The accompanying notes are an integral part of these consolidated financial statements.

Penn Virginia Corporation and Subsidiaries
Consolidated Balance Sheets

(in thousands, except share data)	December 31, 2001	2000
Assets		
Current assets		
Cash and cash equivalents	$ 9,621	$ 735
Accounts receivable	15,403	12,926
Current portion of long-term notes receivable	599	981
Price risk management assets	3,674	–
Other	1,105	652
Total current assets	30,402	15,294
Investments	–	44,080
Property and Equipment		
Oil and gas properties (successful efforts method)	335,494	174,504
Other property and equipment	117,789	83,534
	453,283	258,038
Less: Accumulated depreciation, depletion and amortization	72,095	52,922
Net property and equipment	381,188	205,116
Restricted U.S. Treasury Notes	43,387	–
Other assets	5,194	4,276
Total assets	$ 460,171	$ 268,766
Liabilities and Shareholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 1,235	$ 740
Accounts payable	3,987	2,609
Accrued liabilities	13,831	7,154
Current deferred income taxes	–	136
Taxes on income	–	7,296
Total current liabilities	19,053	17,935
Other liabilities	8,877	5,486
Deferred income taxes	55,861	26,683
Long-term debt	3,500	47,500
Long-term loan	43,387	–
Minority interest	144,039	–
Commitments and contingencies (Note 19)		
Shareholders' equity		
Preferred stock of $100 par value – Authorized 100,000 shares; none issued	–	–
Common stock of $6.25 par value – 16,000,000 shares authorized; 8,921,866 shares issued	55,762	55,762
Paid-in capital	9,869	8,100
Retained earnings	119,125	92,718
Accumulated other comprehensive income	1,756	26,606
	186,512	183,186
Less: 23,765 shares in 2001 and 524,108 in 2000 of common stock held in treasury, at cost	599	10,974
Unearned compensation – ESOP	459	1,050
Total shareholders' equity	185,454	171,162
Total liabilities and shareholders' equity	$ 460,171	$ 268,766

The accompanying notes are an integral part of these consolidated financial statements.

Penn Virginia Corporation and Subsidiaries
Consolidated Statements of Shareholders' Equity

(in thousands, except share data)	*Shares Outstanding*	*Common Stock*	*Paid-in Capital*	*Accumulated Other Retained Earnings*	*Comprehensive Income*	*Unearned Treasury Stock*	*Total Compensation ESOP*	*Stockholders' Comprehensive Equity*	*Comprehensive Income (Loss)*
Balance at December 31, 1998	8,366,816	$ 55,762	$ 8,441	$ 53,924	$ 65,985	$ (12,403)	$ (1,450)	$ 170,259	$ 12,076
Dividends paid ($0.90 per share)	–	–	–	(7,568)	–	–	–	(7,568)	
Stock issued as compensation	7,878	–	(13)	–	–	176	–	163	
Exercise of stock options	48,934	–	(365)	–	–	1,085	–	720	
Allocation of ESOP shares	–	–	33	–	–	–	200	233	
Net income	–	–	–	14,504	–	–	–	14,504	$ 14,504
Other comprehensive loss, net of tax	–	–	–	–	(23,968)	–	–	(23,968)	(23,968)
Balance at December 31, 1999	8,423,628	55,762	8,096	60,860	42,017	(11,142)	(1,250)	154,343	$ (9,464)
Dividends paid ($0.90 per share)	–	–	–	(7,407)	–	–	–	(7,407)	
Purchase of treasury stock	(363,430)	–	–	–	–	(6,761)	–	(6,761)	
Stock issued as compensation	11,163	–	–	–	–	226	–	226	
Exercise of stock options	326,397	–	(63)	–	–	6,703	–	6,640	
Allocation of ESOP shares	–	–	67	–	–	–	200	267	
Net income	–	–	–	39,265	–	–	–	39,265	$ 39,265
Other comprehensive loss, net of tax	–	–	–	–	(15,411)	–	–	(15,411)	(15,411)
Balance at December 31, 2000	8,397,758	55,762	8,100	92,718	26,606	(10,974)	(1,050)	171,162	$ 23,854
Dividends paid ($0.90 per share)	**–**	**–**	**–**	**(7,930)**	**–**	**–**	**–**	**(7,930)**	
Purchase of treasury stock	**(33,991)**	**–**	**–**	**–**	**(638)**	**–**	**(638)**		
Stock issued as compensation	**8,281**	**–**	**142**	**–**	**–**	**188**	**–**	**330**	
Exercise of stock options	**526,053**	**–**	**1,417**	**–**	**–**	**11,216**	**–**	**12,633**	
Allocation of ESOP shares	**–**	**–**	**210**	**–**	**–**	**(391)**	**591**	**410**	
Net income	**–**	**–**	**–**	**34,337**	**–**	**–**	**–**	**34,337**	**$ 34,337**
Other comprehensive loss, net of tax	**–**	**–**	**–**	**–**	**(24,850)**	**–**	**–**	**(24,850)**	**(24,850)**
Balance at December 31, 2001	**8,898,101**	**$ 55,762**	**$ 9,869**	**$ 119,125**	**$ 1,756**	**$ (599)**	**$ (459)**	**$ 185,454**	**$ 9,487**

The accompanying notes are an integral part of these consolidated financial statements.

Penn Virginia Corporation and Subsidiaries
Consolidated Statements of Cash Flows

(in thousands)	2001	2000	1999
	Year Ended December 31,		
Cash flows from operating activities:			
Net income	$ 34,337	$ 39,265	$ 14,504
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	19,579	12,027	8,393
Impairment of oil and gas properties	33,583	–	–
Gain on the sale of property and equipment	(492)	(24,795)	(280)
Gain on sale of securities	(54,688)	–	–
Deferred income taxes	(1,888)	7,006	2,805
Tax benefit from stock option exercises	2,933	1,049	86
Dry hole and unproved leasehold expense	8,953	3,154	1,115
Minority interest	1,763	–	–
Other	479	140	(1,284)
	44,559	37,846	25,339
Changes in operating assets and liabilities:			
Accounts receivable	(2,477)	(6,046)	(1,198)
Other current assets	(2,041)	161	(133)
Accounts payable and accrued liabilities	8,055	2,723	604
Taxes on income	(7,296)	7,296	(576)
Other assets and liabilities	3,391	(240)	1,105
Net cash flows provided by operating activities	44,191	41,740	25,141
Cash flows from investing activities:			
Proceeds from the sale of securities	57,525	–	–
Proceeds from the sale of property and equipment	1,416	55,208	299
Payments received on long-term notes receivable	1,052	926	1,670
Purchase of restricted U.S. Treasury Notes	(43,387)	–	–
Property and lease acquisitions	(149,507)	(36,787)	(46,714)
Capital expenditures	(46,531)	(22,656)	(13,937)
Net cash flows used in investing activities	(179,432)	(3,309)	(58,682)
Cash flows from financing activities:			
Dividends paid	(7,930)	(7,407)	(7,568)
Proceeds from borrowings	147,895	33,240	44,500
Repayment of borrowings	(191,400)	(63,509)	(3,990)
Proceeds from term loan	43,387	–	–
Proceeds from initial public offering, net	142,373	–	–
Purchases of treasury stock	(638)	(6,761)	–
Issuance of stock	10,440	6,084	1,031
Net cash flows provided by (used in) financing activities	144,127	(38,353)	33,973
Net increase (decrease) in cash and cash equivalents	8,886	78	432
Cash and cash equivalents – beginning of year	735	657	225
Cash and cash equivalents – end of year	$ 9,621	$ 735	$ 657
Supplemental disclosures:			
Cash paid during the year for:			
Interest (Net of amount capitalized)	$ 3,131	$ 8,304	$ 2,980
Income taxes	$ 28,772	$ 4,614	$ 2,100
Noncash investing activities:			
Note receivable for sale of property and equipment	$ –	$ –	$ 1,255
Deferred tax liabilities related to acquisition	$ 44,280	$ –	$ –

The accompanying notes are an integral part of these 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 southern portions of the United States. In addition, through our controlling ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"), a Delaware limited partnership, we conduct our coal operations (see "Note 2. PVR – Initial Public Offering and Concurrent Transactions").

The Partnership enters into leases with various third-party operators for the right to mine coal reserves on the Partnership's land in exchange for royalty payments. The lessees make payments based on the higher of a percentage of the gross sales price or a fixed price per ton of coal they sell, 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 to enhance coal production and to generate additional coal services revenues.

2. PVR – Initial Public Offering and Concurrent Transactions

On October 30, 2001, PVR completed an initial public offering of 7.5 million common units (including the underwriter's over-allotment), representing limited partner interests in the Partnership and received proceeds of $142.4 million, after underwriting and offering costs.

In conjunction with the offering, Penn Virginia contributed the assets, liabilities and operations of its coal operations in exchange for i) 1,149,880 common units, 7,649,880 subordinated units and a 2 percent general partner interest; ii) the right to receive incentive distributions (as defined); and iii) cash of approximately $141.5 million representing the repayment of intercompany debt. In addition, after the initial public offering, we sold 975,000 of our common units to the Partnership in connection with the sale of the underwriter's overallotment. After the sale of the 975,000 common units we owned 174,880 units in the Partnership. We used the proceeds from the offering to repay our indebtedness.

In addition, at the closing of the offering, the Partnership borrowed $43.4 million under its term loan facility with PNC Bank and other lenders (see "Note 10. Long-term Debt").

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 our subordinated units convert to common units, we will recognize any gain or loss computed at that time, as paid-in capital. Our subordinated units automatically convert to common units on September 30, 2006, but a portion of the subordinated units may convert after September 30, 2004 if the Partnership meets certain financial tests, namely operating surpluses that exceed the minimum quarterly distributions.

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 52 percent ownership interest. Penn Virginia Resource GP, LLC, a wholly-owned subsidiary of Penn Virginia, serves as the Partnership's sole general partner. 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.

New Accounting Standards

On January 1, 2001, we adopted the Statement of Financial Accounting Standards ("SFAS") No. 133 Accounting for Derivative Instruments and Hedging Activities as amended by SFAS 137 and SFAS 138. Under SFAS 133, all derivative instruments are recorded on the balance sheet at fair value. 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 use only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. If the derivative qualifies for cash flow hedge accounting, the gain or loss on the derivative is deferred in Other Comprehensive Income, a component of Shareholders' Equity, to the extent the hedge is effective. Any hedge ineffectiveness is recorded immediately in the statement of income in natural gas or crude oil production revenues.

If we determine that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

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

This initial adoption of SFAS No. 133 on January 1, 2001, did not have a material effect on our financial position or results of operations (see Note 7. Price Risk Management Activities).

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143 Accounting for Asset Retirement Obligations. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred with the associated asset retirement costs being capitalized as a part of the carrying amount of the long-lived asset. SFAS No. 143 also includes disclosure requirements that provide a description of asset retirement obligations and reconciliation of changes in the components of those obligations. We currently record our plugging and abandoning costs (net of salvage value) with respect to our oil and gas properties as additional depreciation and depletion expense using the units-of-production method. This statement would require us to recognize a liability for the fair value of our plugging and abandoning liability (excluding salvage value) with the associated costs as part of our oil and gas property balance. We are evaluating the future financial reporting effect of adopting SFAS No. 143 and will adopt the standard effective January 1, 2003.

In August 2001, the Financial Accounting Standards Board issued SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets. This Statement supersedes SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, and the accounting and reporting provisions of APB No. 30, Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions, for the disposal of a segment of a business. SFAS No. 144 addresses financial accounting and reporting for the impairment of disposal of long-lived assets. We will adopt the provisions of this Statement in the first quarter of 2002. Under present conditions, management does not expect the initial adoption of SFAS 144 to have a material effect on the financial position, results of operations or liquidity.

Use of Estimates

Preparation of the accompanying consolidated financial statements in conformity with accounting principles generally accepted in the United States 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/Restricted U.S. Treasury Notes

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. In addition, the Partnership has restricted cash in the form of U.S. Treasury Notes that are used to secure the Partnership's term loan facility (see "Note 10. Long-Term Debt"). The intended use of the restricted U.S. Treasury Notes is to purchase property and equipment. The average interest rate received on the U.S. Treasury Notes was 1.7 percent for 2001.

Investments

Investments consist of publicly traded equity securities. We classify our equity securities as available-for-sale. Available-for-sale securities are recorded at fair value based upon market quotations. Unrealized holding gains and losses, net of the related tax effect, on available-for-sale securities are excluded from earnings and are reported as a separate component of stockholders' equity until realized (see "Note 17. Accumulated Other Comprehensive Income"). A decline in the market value of any available-for-sale security below cost that is deemed other than temporary, is charged to earnings in the period it occurs resulting in the establishment of a new cost basis for the security. Dividend income is recognized when earned. Realized gains and losses for securities classified as available-for-sale are included in earnings and are derived using the specific identification method for determining the cost of securities sold (see "Note 5. Investments and Dividend Income").

Notes Receivable

Notes receivable are recorded at cost, adjusted for amortization of discounts. Discounts are amortized over the life of the notes receivable using the effective interest rate method.

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, to drill and equip development wells including development dry holes, and to drill and equip exploratory wells that find proved reserves are capitalized. Capitalized costs of producing oil and gas fields are amortized using the unit-of-production method based on estimates of proved oil and gas reserves on a field-by-field basis. Oil and gas reserve quantities represent estimates only and there are numerous uncertainties inherent in the estimation process. Actual future production may be materially different from amounts estimated and such differences could materially affect future amortization of proved properties. Estimated costs (net of salvage value) of plugging and abandoning oil and gas wells are reported as additional depreciation and depletion expense using the units-of-production method.

The costs of unproved leaseholds are capitalized pending the results of exploration efforts. 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. Exploratory costs including exploratory dry holes, annual delay rental and geological and geophysical costs are charged to expense when incurred.

Other Property and Equipment

Other property and equipment is carried at cost and includes expenditures for additions and improvements, which substantially increase the productive lives of existing assets. Maintenance and repair costs are expensed as incurred. Depreciation of property and equipment is generally computed using the straight-line method over their estimated useful lives, varying from 3 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 are removed from the accounts. The difference between undepreciated cost and proceeds from disposition is recorded as 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 accounted for using the successful efforts method of accounting, 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 expected future net cash flows from proved reserves, utilizing a risk-adjusted rate of return.

Concentration of Credit Risk

Substantially all of our accounts receivable at December 31, 2001 result 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.

Substantially all of the Partnership's accounts receivable at December 31, 2001 result from billings to third party companies in the coal industry. This concentration of customers 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 customer or a lessee, the Partnership analyzes the entity's net worth, cash flows, earnings and credit ratings. Receivables are generally not collateralized. Historical credit losses incurred by the Partnership on receivables have not been significant.

Risk Factors

Our revenues, profitability, cash flow and future growth rates are substantially dependent upon the price of and demand for natural gas and oil and to a lesser extent coal. Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. We are also dependent upon the continued success of our exploratory drilling program. Other factors that could affect revenues, profitability, cash flow and future growth rates include the inherent uncertainties in oil, natural gas and coal reserve estimates, hedging of our oil and natural gas production with derivative instruments and ability to replace oil, natural gas and coal reserves and finance growth.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, marketable securities, accounts receivable, notes receivables, U.S. Treasury Notes, accounts payable and long-term debt. The carrying values of cash, marketable securities, accounts receivables, U.S. Treasury Notes, accounts payables, and long-term debt approximate fair value. The interest rate on our U.S. Treasury Notes and debt is subject to market fluctuations.

The fair value of notes receivable at December 31, 2001 and 2000 was $4.6 million and $5.4 million, respectively.

Revenues

Oil and Gas. Oil and gas sales revenues are recognized when production is delivered to the buyer. We recognize our natural gas revenue using the entitlement method in which we recognize our ownership interest in natural gas production as revenue. Each working interest owner in a well generally has the right to a specific percentage of production, although actual production sold may differ from an ownership percentage. Using entitlement accounting, a receivable is recorded when under-production occurs and deferred revenue is recognized when over-production occurs.

Coal Royalties. Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenue from those sales. Most coal leases are based on minimum monthly or annual payments, a minimum dollar royalty per ton and/or a percentage of the gross sales price.

Timber. Timber is sold on a contract basis where independent contractors harvest and sell the timber and, from time to time, in a competitive bid process involving sales of standing timber on individual parcels. Timber revenues are recognized when the timber has been sold or 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.

Coal Services. Coal services revenues are recognized when lessees use the Partnership's facilities for the processing and 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 plant, dock loading facility and short-line railroad under operating lease agreements. Revenues associated with coal services are included in other revenues.

Minimum Rentals. Most of the Partnership's lessees must 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 recoupment period), the deferred income attributable to the minimum payment is recognized as minimum rental revenues.

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.

4. Acquisitions and Dispositions

On July 23, 2001, we acquired all of the outstanding stock of Synergy Oil & Gas, Inc., a Texas corporation. Synergy was a privately owned independent exploration and production company with operations primarily in the Texas onshore Gulf Coast and West Texas areas. Cash consideration for the stock was approximately $112 million, which was funded by advances under our revolving credit facility and available cash on hand. The total purchase price was allocated to the assets purchased and the liabilities assumed in the Synergy transaction based upon the fair values on the date of acquisition, as follows:

(in thousands)	
Value of oil and gas properties acquired	$ 157,120
Net assets acquired, excluding oil and gas properties	351
Deferred income tax liability	(45,271)
Cash paid, net of cash acquired	$ 112,200

The following unaudited Pro Forma results of operations have been prepared as though the acquisition had been completed on January 1, 2000. The unaudited Pro Forma results of operations for the years ended December 31, 2001 and 2000 are as follows:

(in thousands, except share data):	2001	2000
Revenues	$ 114,629	$ 128,127
Net income	$ 40,026	$ 33,773
Net income per share, diluted	$ 4.50	$ 4.03

5. Investments and Dividend Income

In April 2001, we sold all of our 3.3 million common share position in Norfolk Southern Corporation and other stocks classified as available-for-sale. The Norfolk Southern Corporation shares were sold at an average price of $17.39 per share. Proceeds from the sales, net of commissions, totaled approximately $57.4 million. We recorded a pre-tax gain on the stock sale transactions of approximately $54.7 million.

Dividend income from our investment in Norfolk Southern Corporation was $0.2 million for the year ended December 31, 2001 and $2.6 million for each of the two years ended December 31, 2000, and 1999.

6. Notes Receivable

At December 31, 2001, we had two notes receivable outstanding included in Other assets. One note relates to the sale of property and equipment in 1999 for which we received a $1.3 million note for a portion of the proceeds. This note will be repaid in full in 2002. The other note receivable relates to the sale of coal properties located in Virginia in 1986. The note has a stated interest rate of 6.0% per annum and had an original principal amount of $15.0 million pursuant to which we receive quarterly payments through July 1, 2005. In addition, we own a 50 percent residual interest in any royalty income generated from the coal properties sold which are mined after July 1, 2005.

Our notes receivable are collateralized by property and equipment. Maturities of notes receivable are as follows:

(in thousands)	December 31, 2001	2000
Current	$ 599	$ 981
Due after one year through five years	1,757	2,427
	$ 2,356	$ 3,408

7. Price Risk Management Activities

The Company, from time to time, enters into derivative financial instruments to mitigate its exposure to natural gas price volatility. The derivative financial instruments, which are placed with a major financial institution that we believe is a minimum credit risk, take the form of costless collars and swaps. Effective January 1, 2001, the derivative financial instruments were recognized in the financial statements at fair value in accordance with SFAS 133, as amended by SFAS 137 and SFAS 138.

Based upon our assessment of our derivative contracts at December 31, 2001, we reported (i) a net asset of $3.1 million and (ii) accumulated other comprehensive income of $2.0 million, net of income taxes of $1.1 million. In connection with monthly settlements, we recognized net hedging gains in natural gas and oil revenues of $1.9 million for the year ended December 31, 2001. Based upon future oil and natural gas prices as of December 31, 2001, $3.1 million is expected to be reclassified to earnings within the next 12 months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement. We had no outstanding derivative financial instruments at December 31, 2000 or 1999.

As of February 18, 2002 our commodity price risk management positions on average daily volumes for the full year 2002 are as follows:

Natural Gas Collar Arrangements

- 11,258 MMbtus at a weighted average floor price of $3.22 per MMbtu and ceiling price of $4.14 per MMbtu through December 2002

Natural Gas Swap Contracts

- 13,000 MMbtus at a NYMEX price of $2.74 per MMbtu expiring October 2002

Crude Oil Collar Arrangements

- 764 Bbls at a weighted average floor price of $21.31 per Bbl and ceiling price of $25.72 per Bbl through December 2002

All hedge transactions are subject to our risk management policy, approved by the Board of Directors. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedge transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

8. Property and Equipment

Property and equipment includes:

(in thousands)	December 31, 2001	2000
Oil and gas properties		
Unproved	$ 58,880	$ 2,425
Proved	276,614	172,079
Other property and equipment:		
Land	1,773	1,809
Timber	188	188
Coal properties	106,270	72,952
Other equipment	9,558	8,585
	453,283	258,038
Less: Accumulated depreciation, depletion and amortization	(72,095)	(52,922)
Net property and equipment	$ 381,188	$ 205,116

9. Impairment of Oil and Gas Properties

In accordance with SFAS No. 121, we review oil and gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. Due to low commodity prices in the fourth quarter of 2001, we estimated the expected future cash flows of our oil and gas properties and compared such future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount was recoverable. For our oil and gas properties located primarily in Texas, the carrying amount of the properties exceeded the estimated undiscounted future cash flows; thus, we adjusted the carrying amount of the respective oil and gas 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, timing of future production, future capital expenditures and a discount rate commensurate with our internal rate of return on our oil and gas properties.
As a result, we recognized a non-cash pre-tax charge of $33.6 million ($21.8 million after tax) related to the impairment of oil and gas properties in the fourth quarter of 2001. There were no impairments of oil and gas properties in 2000 or 1999.

10. Long-Term Debt

Long-term debt consists of the following:

(in thousands)	December 31, 2001	2000
Penn Virginia revolving credit facility, variable rate of 3.3% at December 31, 2000, due in 2004	$ 3,500	$ 47,500
PVR Term loan, Variable rate of 2.4 % at December 31, 2001, due in 2004	43,387	–
Line of credit	1,235	740
	48,122	48,240
Less: current maturities	(1,235)	(740)
Total long-term debt	$ 46,887	$ 47,500

The aggregate maturities applicable to outstanding debt at December 31, 2001 are $1.2 million in 2002 and $46.9 million in 2004.

Penn Virginia Revolving Credit Facility

We have a $150 million secured revolving credit facility (the "Revolver") at December 31, 2001 with a group of major banks, and a borrowing base of $140 million.

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 1.375 to 1.875 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 0.375 to 0.875 percent. The weighted average interest rate on borrowings incurred during the year ended December 31, 2001 was approximately 5.9 percent. The Revolver allows for issuance of letters of credit that are limited to no more than $10 million. At December 31, 2001, letters of credit issued were $0.3 million. The financial covenants require us to maintain levels of net worth, debt-to-earnings and dividend limitation restrictions. We are currently in compliance with all of our covenants.

PVR Revolving Credit Facility

The Partnership has a $50.0 million unsecured revolving credit facility (the "Partnership Revolver"), which expires in October 2004, with a group of major banks. The Partnership has the option to elect interest at (i) LIBOR plus a Euro-rate margin ranging from 1.25 percent to 1.75 percent, based on certain financial data or (ii) the greater of the prime rate or federal funds rate plus 0.5 percent. The Partnership Revolver allows for working capital draws of no more than $5.0 million and issuance of letters of credit, which are limited to $2 million. The financial covenants of the Partnership Revolver include, but are not limited to, maintaining: (i) a ratio of not more than 2.5:1.0 of total debt to consolidated EBITDA (as defined by the credit agreement) and (ii) a ratio of not less than 4.00:1.00 of consolidated EBITDA to fixed charges. There were no amounts outstanding under the Partnership Revolver at December 31, 2001. The Partnership is currently in compliance with all of its covenants.

PVR Term Loan

The Partnership borrowed an additional $43.4 million in the form of a term loan. The term loan expires in October 2004 and is secured by restricted U.S. Treasury Notes. The Partnership has the option to elect interest at (i) LIBOR plus a Euro-rate margin 0.5 percent, based on certain financial data or (ii) the greater of the prime rate or federal funds rate plus 0.5 percent. The financial covenants of the term loan include, but are not limited to, maintaining certain levels of financial leverage, interest coverage and cash flow.

Line of Credit

We have a $5 million line of credit with a financial institution due in December 2002, renewable annually. We have an option to elect either a fixed rate LIBOR loan, floating rate LIBOR loan or base rate loan.

11. Accrued Liabilities

Accrued expenses are summarized as follows:

(in thousands)	December 31, 2001	2000
Gas imbalances	$ 3,128	$ 1,310
Taxes other than income	2,700	1,013
Accrued oil and gas royalties	2,042	2,027
Compensation	1,949	1,421
Accrued drilling costs	1,641	197
Other	2,371	1,186
Total accrued liabilities	$ 13,831	$ 7,154

12. Income Taxes

The provision for income taxes from continuing operations is comprised of the following:

(in thousands)	Year ended December 31, 2001	2000	1999
Current income taxes			
Federal	$ 21,160	$ 10,463	$ 1,525
State	42	2,496	–
Total current	21,202	12,959	1,525
Deferred income taxes			
Federal	(3,167)	6,951	2,426
State	1,279	55	379
Total deferred	(1,888)	7,006	2,805
Total income tax expense	$ 19,314	$ 19,965	$ 4,330

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:

	Year ended December 31,		
(in thousands)	**2001**	2000	1999
Computed at federal statutory tax rate	**$ 18,777**	$ 20,731	$ 6,592
State income taxes, net of federal income tax benefit	**859**	1,658	246
Dividends received deduction	**(49)**	(648)	(648)
Non-conventional fuel source credit	**(721)**	(1,570)	(1,471)
Percentage depletion	**(46)**	(234)	(414)
Other, net	**494**	28	25
Total income tax expense	**$ 19,314**	$ 19,965	$ 4,330

The principal components of our net deferred income tax liability are as follows:

	December 31,	
(in thousands)	**2001**	2000
Deferred tax assets:		
Other long-term assets	**$ 2,703**	$ 1,908
Alternative minimum tax credits	**439**	2,258
Net operating loss carryforwards	**1,154**	925
Other	**178**	560
Total deferred tax assets	**4,474**	5,651
Deferred tax liabilities:		
Notes receivable	**(747)**	(891)
Investments	**–**	(14,437)
Oil and gas properties	**(56,675)**	(14,789)
Other property and equipment	**(2,108)**	(2,142)
Other	**(805)**	(211)
Total deferred tax liabilities	**(60,335)**	(32,470)
Net deferred tax liability	**(55,861)**	(26,819)
Less: Net current deferred income tax asset (liability)	**–**	(136)
Net non-current deferred tax liability	**$ (55,861)**	$ (26,683)

During 2001, we increased our non-current deferred tax liability by $44.3 million relating to the acquisition of Synergy Oil and Gas, Inc. offset by a decrease of $14.4 million relating to the sale of Norfolk Southern Corporation common stock.

As of December 31, 2001, we had available alternative minimum tax credits of approximately $0.4 million, which can be carried forward indefinitely as a credit. We have various net operating loss carryforwards for tax purposes of approximately $11.4 million which, if unused, will expire from 2009 to 2021.

13. Pension Plans and Other Post-retirement Benefits

We provide early retirement programs for eligible employees. Benefits are recorded based on the employee's average annual compensation and yearly services. We provided a noncontributory, defined benefit pension plan, which was frozen in 1996, and terminated in 2001. We recorded an expense of $0.5 million relating to the termination of the retirement plan in 2001.

We also sponsor a defined benefit post-retirement plan that covers employees hired prior to January 1, 1991 who retire from active service. The plan provides medical benefits 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.

A reconciliation of the changes in the benefit obligations and fair value of assets for the two years ended December 31, 2001 and 2000 and a statement of the funded status at December 31, 2001 and 2000 is as follows:

	Pension		Post-retirement Healthcare	
(in thousands)	**2001**	2000	**2001**	2000
Reconciliation of benefit obligation:				
Obligation – beginning of year	**$ 10,467**	$ 10,612	**$ 2,853**	$ 2,936
Service cost	**43**	43	**11**	11
Interest cost	**744**	763	**251**	209
Benefits paid	**(1,754)**	(1,087)	**(577)**	(324)
Settlements	**(7,879)**	–	**–**	–
Actuarial (gain) loss	**797**	113	**930**	21
Other	**(43)**	23	**–**	–
Obligation – end of year	**2,375**	10,467	**3,468**	2,853
Reconciliation of fair value of plan assets:				
Fair value – beginning of year	**9,941**	10,594	**975**	1,578
Actual return on plan assets	**368**	223	**138**	(301)
Settlements	**(7,879)**	–	**–**	–
Employer contributions	**259**	259	**10**	25
Participant contributions	**–**	–	**11**	5
Benefit payments	**(1,754)**	(1,087)	**(588)**	(324)
Administrative expenses	**(190)**	(48)	**(28)**	(8)
Transfer to 401 K	**(186)**	–	**–**	–
Reversion to Penn Virginia	**(559)**	–	**–**	–
Fair value – end of year	**–**	9,941	**518**	975
Funded status:				
Funded status – end of year	**(2,375)**	(526)	**(2,950)**	(1,878)
Unrecognized transition obligation	**20**	23	**–**	–
Unrecognized prior service cost	**42**	48	**79**	86
Unrecognized (gain) loss	**405**	(308)	**930**	118
Net amount recognized	**$ (1,908)**	$ (763)	**$ (1,941)**	$ (1,674)

The following table provides the amounts recognized in the statements of financial position at December 31, 2001 and 2000:

	Pension		Post-retirement Healthcare	
(in thousands)	**2001**	2000	**2001**	2000
Accrued benefit liability	**$ (2,375)**	$ (1,199)	**$ (1,941)**	$ (1,674)
Other long-term assets	**62**	71	**–**	–
Accumulated other comprehensive income	**405**	365	**–**	–
Obligation – end of year	**$ (1,908)**	$ (763)	**$ (1,941)**	$ (1,674)

The following table provides the components of net periodic benefit cost for the plans for the two years ended December 31, 2001 and 2000:

	Pension		Post-retirement Healthcare	
(in thousands)	**2001**	2000	**2001**	2000
Service cost	**$ 43**	$ 43	**$ 11**	$ 11
Interest cost	**745**	763	**251**	209
Expected return on plan assets	**(901)**	(963)	**(23)**	(42)
Amortization of prior service cost	**6**	6	**6**	6
Amortization of transitional obligation	**3**	3	**–**	–
Recognized actuarial (gain) loss	**8**	(21)	**32**	–
Net periodic benefit cost	**$ (96)**	$ (169)	**$ 277**	$ 184

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

	Pension		Post-retirement Healthcare	
	2001	2000	**2001**	2000
Discount rate	**7.25%**	7.50%	**7.25%**	7.50%
Expected return on plan assets	**9.50**	9.50	**3.00**	3.00

For measurement purposes, a 10.0 percent annual rate increase in the per capita cost of covered health care benefits was assumed for 2001. The rate is assumed to decrease gradually to 5.0 percent for 2011 and remain at that level thereafter.

For measurement purposes, a 10.0 percent annual rate increase in the per capita cost of covered health care benefits was assumed for 2001. The rate is assumed to decrease gradually to 5.0 percent for 2011 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 2001:

(in thousands)	One percent Increase	One percent Decrease
Effect on total of service and interest cost components	$ 11	$ (10)
Effect on post-retirement benefit obligation	163	(148)

14. Other Liabilities

Other liabilities are summarized in the following table:

	December 31,	
(in thousands)	**2001**	2000
Post-retirement health care	**$ 1,793**	$ 1,497
Deferred income	**3,658**	2,749
Pension	**2,234**	1,059
Other	**1,192**	181
Total other liabilities	**$ 8,877**	$ 5,486

15. 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 net income for the three years ended December 31:

(in thousands, except share data.)	**2001**	2000	1999
Net income	**$ 34,337**	$ 39,265	$ 14,504
Weighted average shares, basic	**8,770**	8,241	8,406
Effect of Dilutive securities:			
Stock options	**126**	130	74
Weighted average shares, diluted	**8,896**	8,371	8,480
Net income per share, basic	**$ 3.92**	$ 4.76	$ 1.73
Net income per share, diluted	**$ 3.86**	$ 4.69	$ 1.71

Antidilutive stock options are precluded from the computation of diluted EPS; however, such options could potentially dilute basic EPS in the future.

16. Stock Option and Stock Ownership Plans

Stock Option Plans

We have several stock option plans (collectively known as the "Stock Option Plans") that allow incentive and nonqualified stock options to be granted to key employees and officers and nonqualified stock options to be granted to directors. Options granted under the Stock Option Plans may be exercised at any time after one year and prior to ten years following the grant, subject to special rules that apply in the event of death, retirement and/or termination of an optionee. The exercise price of all options granted under the Stock Option Plans is at the fair market value of the Company's stock on the date of the grant. At December 31, 2001 there were 300,000 and 250,000 options authorized and available to grant to Directors and employees, respectively.

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

	2001		2000		1999	
	Shares Under Options	Weighted Avg. Exercise Price	Shares Under Options	Weighted Avg. Exercise Price	Shares Under Options	Weighted Avg. Exercise Price
Outstanding, Beginning of year	725,403	$ 19.38	1,014,500	$ 18.74	1,002,800	$ 18.65
Granted	160,100	$ 32.02	46,300	$ 16.65	91,800	$ 20.27
Exercised	526,053	$ 23.35	326,397	$ 17.13	49,000	$ 16.44
Cancelled	–	–	9,000	$ 18.99	31,100	$ 23.84
Outstanding, End of year	359,450	$ 25.97	725,403	$ 19.38	1,014,500	$ 18.74
Weighted average of fair value of options granted during the year		$ 10.55		$ 5.02		$ 6.02

The following table summarizes certain information regarding stock options outstanding at December 31, 2001:

Options Outstanding				Options Exercisable	
Range of Exercise Price	Number Outstanding at 12/31/01	Weighted Avg. Remaining Contractual Life	Weighted Avg. Exercise Price	Number Exercisable at 12/31/01	Weighted Avg. Exercise Price
$15 to $19	55,200	5.9	$ 17.46	55,200	$ 17.46
$20 to $24	127,900	5.2	$ 21.90	127,900	$ 21.90
$25 to $29	26,280	7.0	$ 27.11	26,250	$ 27.11
$30 to $34	150,100	9.5	$ 32.36	–	$ –

We apply the intrinsic value method for reporting compensation expense pursuant to Accounting Principles Board Opinion No. 25 "Accounting for Stock Issued to Employees" to its stock-based compensation plans. Had compensation expense for our stock-based compensation plans been determined in accordance with the fair value method pursuant to SFAS No. 123 "Accounting for Stock-Based Compensation", our pro forma net income and earnings per share would have been as follows:

	2001	2000	1999
Net Income (in thousands)	$ 33,652	$ 39,092	$ 14,111
Earnings per share, basic	$ 3.84	$ 4.74	$ 1.68
Earnings per share, diluted	$ 3.78	$ 4.67	$ 1.66

The fair value of the options granted during 2001 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 2.71 percent to 2.92 percent, b) expected volatility of 32.3 percent, c) risk-free interest rate 5.1 percent and d) expected life of eight years

The fair value of the options granted during 2000 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 5.2 percent to 5.4 percent, b) expected volatility of 37.0 percent, c) risk-free interest rate of 6.9 percent to 7.0 percent and d) expected life of eight years.

The fair value of the options granted during 1999 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 4.4 percent to 4.6 percent, b) expected volatility of 38.6 percent, c) risk-free interest rate of 4.8 percent to 4.9 percent and d) expected life of eight years.

The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts.

Employees' Stock Ownership Plan

In 1996, the Board of Directors extended the Employees' Stock Ownership Plan ("ESOP"). All employees with one year of service are participants. The ESOP is designed to enable employees to accumulate stock ownership. While there are no employee contributions, participants receive an allocation of stock which has been contributed by the Company. Compensation costs are reported when such shares are released to employees. The ESOP borrowed $2.0 million from the Company in 1996 and used the proceeds to purchase treasury stock. Under the terms of the ESOP, we will make annual contributions over a 10-year period. At December 31, 2001, the unearned portion of the ESOP approximately ($0.5 million) was recorded as a contra-equity account entitled "Unearned Compensation-ESOP."

Shareholder Rights Plan

In February 1998, the Board of Directors adopted a Shareholder Rights Plan designed to prevent an acquirer from gaining control of the Company without offering a fair price to all shareholders. 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 ten days after a person or affiliated group has acquired fifteen percent or more, or makes a tender offer for fifteen percent or more, of the our common stock. Each Right will entitle the holder, under certain circumstances (such as a merger, acquisition of fifteen percent or more of common stock of the Company by the acquiring person or sale of fifty percent or more of the Company's assets or earning power), to acquire at half the value, either common stock of the Company, a combination of cash, other property, or common stock or other securities of the Company, or common stock of the 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 at any time until ten days following the time an acquiring person acquires fifteen percent or more of our common stock at $0.001 per Right.

17. Accumulated Other Comprehensive Income

Comprehensive income represents certain changes in equity during the reporting period, including net income and other comprehensive income, which includes, but is not limited to, unrealized gains 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, 2001, the components of accumulated other comprehensive income are as follows:

(in thousands)	*Net unrealized holding gain – investments*	*Price risk management assets*	*Minimum pension liability*	*Accumulated other comprehensive income*
Balance at December 31, 1998	$ 66,287	$ –	$ (302)	$ 65,985
Unrealized holding loss, net of tax of $12,951	(24,052)	–	–	(24,052)
Pension plan adjustment, net of tax of $46	–	–	84	84
Balance at December 31, 1999	42,235	–	(218)	42,017
Unrealized holding loss, net of tax of $8,308	(15,429)	–	–	(15,429)
Pension plan adjustment, net of tax of $10	–	–	18	18
Balance at December 31, 2000	26,806	–	(200)	26,606
Investment holding gain, net of tax of $1,383	**8,741**	**–**	**–**	**8,741**
Investment reclassification adjustment, net of tax of $19,140	**(35,547)**	**–**	**–**	**(35,547)**
Price risk management unrealized gain, net of tax of $1,940	**–**	**3,603**	**–**	**3,603**
Price risk management reclassification adjustment, net of tax of $853	**–**	**(1,584)**	**–**	**(1,584)**
Pension plan adjustment, net of tax of $34	**–**	**–**	**(63)**	**(63)**
Balance at December 31, 2001	**$ –**	**$ 2,019**	**$ (263)**	**$ 1,756**

18. 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 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 its 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 rights and subsequent collection of royalties and the development and harvesting of timber.

(in thousands)	Oil and Gas	Coal Royalty and Land Management	All Other	Consolidated
December 31, 2001:				
Revenues	$ 57,778	$ 37,513	$ 1,280	$ 96,571
Operating costs and expenses	26,914	9,271	6,044	42,229
Depreciation, depletion and amortization	16,418	3,084	77	19,579
Impairment of oil and gas Properties	33,583	–	–	33,583
Operating income (loss)	$ (19,137)	$ 25,158	$ (4,841)	1,180
Gain on sale of securities				54,688
Interest expense				(2,070)
Interest income				1,602
Other				14
Income before minority interest and taxes				$ 54,414
Total assets	292,448	162,638	5,085	460,171
Capital expenditures	161,292	33,668	1,078	196,038
December 31, 2000:				
Revenues	$ 71,405	$ 30,189	$ 4,404	$ 105,998
Operating costs and expenses	15,107	8,327	4,901	28,335
Depreciation, depletion and amortization	9,883	2,047	97	12,027
Operating income (loss)	$ 46,415	$ 19,815	$ (594)	65,636
Interest expense				(7,878)
Interest income				1,458
Other				14
Income before taxes				$ 59,230
Total assets	142,613	79,803	46,350	268,766
Capital expenditures	58,677	485	281	59,443
December 31, 1999:				
Revenues	$ 23,222	$ 21,350	$ 3,125	$ 47,697
Operating costs and expenses	10,102	5,505	2,982	18,589
Depreciation, depletion and amortization	6,951	1,269	173	8,393
Operating income (loss)	$ 6,169	$ 14,576	$ (30)	20,715
Interest expense				(3,298)
Interest income				1,354
Other				63
Income before taxes				$ 18,834
Total assets	120,954	82,723	70,334	274,011
Capital expenditures	28,605	31,955	91	60,651

Operating loss for the Oil Gas segment in 2001 includes a $33.6 million impairment on properties (see "Note 9. Impairment of Oil and Gas Properties"). Operating income for 2000 includes a gain on sale of property of $23.9 million.

Operating income is total revenue less operating expenses. Operating income does not include certain other income items, gain (loss) on sale of securities, interest expense, minority interest and income taxes. Identifiable assets are those assets used in the operations of each segment.

For the year ended December 31, 2001, two customers of the oil and gas segment accounted for $20.8 million, or 22 percent, and $11.4 million, or 12 percent, respectively, of our consolidated net revenues. For the year ended December 31, 2000, two customers of the oil and gas segment accounted for $13.6 million, or 13 percent, and $10.5 million, or 10 percent, respectively, of our consolidated net revenues.

19. Commitments and Contingencies

Rental Commitments

Minimum rental commitments under all non-cancelable operating leases, primarily real estate, in effect at December 31, 2001 were as follows:

(in thousands)

Year ending December 31,	
2002	$ 1,598
2003	1,390
2004	1,284
2005	1,046
2006	957
Total minimum payments	$ 6,275

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 the coal property leases to monitor their lessee's compliance with environmental laws and regulations, as well as reviewing mine 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 neither incurred, nor is aware of, any material environmental charges imposed on it related to its coal properties for the years ended December 31, 2001, 2000 and 1999.

20. Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The following supplementary 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

	Year Ended December 31,		
(in thousands)	2001	2000	1999
Proved properties	$ 131,444	$ 64,107	$ 41,084
Unproved properties	58,880	2,425	3,959
Wells, equipment and facilities	142,311	105,283	137,176
Support equipment	2,859	2,689	2,829
	335,494	174,504	185,048
Accumulated depreciation and depletion	(60,073)	(43,720)	(69,495)
Net capitalized costs	$ 275,421	$ 130,784	$ 115,553

Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
(in thousands)	2001	2000	1999
Proved property acquisition costs	$ 97,147	$ 35,999	$ 14,069
Unproved property acquisition costs	64,488	917	2,551
Exploration costs	13,406	5,125	3,171
Development costs and other	31,545	18,561	9,398
Total costs incurred	$ 206,586	$ 60,602	$ 29,189

Costs for the year ended December 31, 2001 include deferred income taxes of $45.3 million provided for the book versus tax basis difference related to the acquired Synergy Oil and Gas properties, $27.2 million of which is included in proved property acquisition costs and $18.1 million is included in unproved property acquisition costs.

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 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,		
(in thousands)	2001	2000	1999
Revenues	$ 57,024	$ 46,851	$ 21,847
Production costs	9,833	7,097	5,092
Exploration costs	11,514	5,080	1,699
Depreciation and depletion	16,418	9,883	6,951
Impairment of oil and gas properties	33,583	–	–
	(14,324)	24,791	8,105
Income tax expense (benefit)	(5,860)	8,354	1,864
Results of operations	$ (8,464)	$ 16,437	$ 6,241

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, 2001 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 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 (MBbls)	Natural Gas (MMcf)	MMcfe
December 31, 1998	341	163,873	165,919
Revisions of previous estimates	31	2,106	2,292
Extensions, discoveries and other additions	–	4,661	4,661
Production	(32)	(8,679)	(8,871)
Purchase of reserves	19	23,237	23,351
December 31, 1999	359	185,198	187,352
Revisions of previous estimates	107	(1,893)	(1,251)
Extensions, discoveries and other additions	19	30,987	31,101
Production	(31)	(11,645)	(11,831)
Purchase of reserves	11	35,879	35,945
Sale of reserves in place	(394)	(64,279)	(66,643)
December 31, 2000	71	174,247	174,673
Revisions of previous estimates	(438)	(5,697)	(8,325)
Extensions, discoveries and other additions	90	41,395	41,935
Production	(164)	(13,130)	(14,114)
Purchase of reserves	4,361	33,402	59,568
Sale of reserves in place	–	(964)	(964)
December 31, 2001	3,920	229,253	252,773
Proved Developed Reserves:			
December 31, 1999	326	138,283	140,239
December 31, 2000	71	145,930	146,356
December 31, 2001	2,212	183,134	196,406

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,		
(in thousands)	**2001**	2000	1999
Future cash inflows	**$ 722,203**	$1,727,923	$ 505,685
Future production costs	**178,533**	205,385	151,220
Future development costs	**39,145**	19,981	30,431
Future net cash flows before income tax	**504,525**	1,502,557	324,034
Future income tax expense	**127,277**	422,485	58,068
Future net cash flows	**377,248**	1,080,072	265,966
10% annual discount for estimated timing of cash flows	**188,305**	612,679	146,703
Standardized measure of discounted future net cash flows	**$ 188,943**	$ 467,393	$ 119,263

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
(in thousands)	**2001**	2000	1999
Sales of oil and gas, net of production costs	**$ (47,191)**	$ (39,754)	$ (16,755)
Net changes in prices and production costs	**(483,009)**	313,355	32,111
Extensions, discoveries and other additions	**37,907**	123,223	4,090
Development costs incurred during the period	**13,771**	16,001	5,330
Revisions of previous quantity estimates	**(7,710)**	(4,604)	1,709
Purchase of minerals-in-place	**70,294**	121,979	20,438
Sale of minerals-in-place	**(906)**	(41,456)	–
Accretion of discount	**64,363**	13,628	8,116
Net change in income taxes	**122,636**	(159,220)	(11,526)
Other changes	**(48,605)**	4,978	86
Net increase (decrease)	**(278,450)**	348,130	43,599
Beginning of year	**467,393**	119,263	75,664
End of year	**$ 188,943**	$ 467,393	$ 119,263

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" and the statements of cash flows in the financial statements.

Item 9 | Changes In And Disagreements With Accountants On Accounting And Financial disclosure

None.

Part III

Items 10, 11, 12 And 13 | Directors And Executive Officers Of The Company, Executive Officers Of The Company, Executive Compensation, Security Ownership Of Certain Beneficial Owners And Management, And Certain Relationships And Related transactions

Except for information concerning executive officers of the Company included as an unnumbered item in Part 1, 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.

Part IV

Item 14 | 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 36 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

(1.1) Underwriting agreement dated October 24, 2001, among the Partnership, Penn Virginia Resource GP, LLC and Penn Virginia Operating Co., LLC (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 14, 2001.)

(3.1) Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to the Company'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) Amended bylaws of Registrant (incorporated by reference to Exhibit 3.3 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2000.

(4) 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 with Securities and Exchange Commission on February 20, 1998.)

(10.1) Credit Agreement dated as of October 30, 2001 among Penn Virginia Corporation, the lenders party thereto, First Union National Bank, Bank One, NA, and Royal Bank of Canada, as Co-Syndication Agents, and The Chase Manhattan Bank, as Administrative Agent.

(10.2) Penn Virginia Corporation and Affiliated Companies Employees' Stock Ownership Plan, as amended.

(10.3) Penn Virginia Corporation and Affiliated Companies' Employees' 401(k) Plan, as amended.

(10.4) Registrant has adopted a policy concerning severance benefits for certain senior officers of Registrant. The description of such policy is incorporated herein by reference to the description of such policy contained in Registrant's definitive Proxy Statement dated April 2, 2002.

(10.5) 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).

(10.6) Penn Virginia Corporation 1995 Second Amended and Restated Directors' Stock Compensation Plan, as amended.

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

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

(10.9) Underwriting Agreement dated October 24, 2001 among Registrant, GP, LLC, the Partnership and Operating Co. and Lehman Brothers Inc. and the other underwriters party thereto (the "Partnership") (incorporated by reference to Exhibit 10.1 to Registrant's Report on Form 8-K filed with the Securities and Exchange Commission on November 14, 2001).

(10.10) Agreement and Plan of Merger dated June 19, 2001 among Registrant, Virginia Acquisition Corp. and Synergy Oil & Gas, Inc. (incorporated by reference to Exhibit 10 to Registrant's Report on Form 8-K filed with the Securities and Exchange Commission on August 6, 2001).

(10.11) Asset Purchase and Sale Agreement dated as of May 31, 2001 among Penn Virginia Coal Company, Pen Holdings, Inc., Pen Coal Corporation and the Elk Horn Coal Corporation (incorporated by reference to Exhibit 10 to Registrant's Report on Form 8-K filed with the Securities and Exchange Commission on June 18, 2001).

(21) Subsidiaries of Registrant.

(23.1) Consent of Arthur Andersen LLP.

(99.1) Letter Responsive to Temporary Note 3T to Article 3 of Regulation S-X

(b) Reports on Form 8-K

On November 14, 2001, Registrant filed a report on Form 8-K. The report involved the formation of Penn Virginia Resource Partners, L.P. and was filed under "Item 2. Acquisition or Disposition of Assets."

On October 5, 2001, Registrant filed a Form 8-K/A amending a Report on Form 8-K which had been filed on July 23, 2001.

Corporate Information

From left to right, A. James Dearlove, Nancy M. Synder, Keith D. Horton, Ann N. Horton, Frank A. Pici, and H. Baird Whitehead.

Directors

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

Richard A. Bachmann[2,4]
President and Chief Executive Officer of Energy Partners, Ltd.

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

A. James Dearlove[1]
President and Chief Executive Officer of the Company

Keith D. Horton
Executive Vice President of the Company

Peter B. Lilly[2,3]
President and Chief Executive Officer of Vulcan Coal Holdings, LLC

Marsha Reines Perelman[1,2,3,4]
Chief Executive Officer of Woodforde Management, Inc.

Joe T. Rye[3,4]
President of Joe T. Rye, P.C.

[1] *Member of the Nominating Committee*
[2] *Member of the Compensation & Benefits Committee*
[3] *Member of the Audit Committee*
[4] *Member of the Oil and Gas Committee*

PVA 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
Vice President, General Counsel and Corporate Secretary

Ann N. Horton
Vice President and Controller

Nancy J. Heiden
Assistant Secretary

Suzanne J. Feldman
Assistant Treasurer

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 7, 2002 at
The Desmond Great Valley Hotel and Conference Center
One Liberty Boulevard
Malvern, PA 19355
Telephone: (610) 296-9800
Facsimile: (610) 889-9869

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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