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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2004

Or

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

For the transition period from ____________ to ____________

Commission File Number 1-13283

PENN VIRGINIA CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Virginia	23-1184320
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

THREE RADNOR CORPORATE CENTER, SUITE 230
100 MATSONFORD ROAD
RADNOR, PA 19087

(Address of Principal Executive Office) (Zip Code)

(610) 687-8900

(Registrant's Telephone Number, Including Area Code)

(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X No ____

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes X No ____

As of August 2, 2004, 18,356,769 shares of common stock of the registrant were issued and outstanding.

PENN VIRGINIA CORPORATION
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PART I. Financial Information
Item 1. Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Revenues				
Natural gas	$ 32,444	$ 25,904	$ 66,408	$ 55,904
Oil and condensate	3,030	4,314	6,518	8,627
Coal royalties	17,517	12,247	34,377	23,698
Coal services	942	546	1,726	1,039
Timber	142	193	295	749
Other	494	499	871	1,702
Total revenues	54,569	43,703	110,195	91,719
Expenses				
Lease operating	5,469	4,282	10,313	7,873
Exploration	1,835	3,712	7,395	7,962
Taxes other than income	2,464	2,995	5,494	6,068
General and administrative	5,749	5,897	11,431	11,838
Depreciation, depletion and amortization	13,387	12,010	27,543	24,358
Total expenses	28,904	28,896	62,176	58,099
Operating income	25,665	14,807	48,019	33,620
Other income (expense)				
Interest expense	(1,464)	(1,521)	(2,854)	(2,457)
Interest and other income	258	211	532	650
Income before minority interest, income taxes and cumulative effect of change in accounting principle	24,459	13,497	45,697	31,813
Minority interest	4,695	2,823	9,198	5,842
Income tax expense	7,684	4,312	14,277	10,486
Income before cumulative effect of change in accounting principle	12,080	6,362	22,222	15,485
Cumulative effect of change in accounting principle	-	-	-	1,363
Net income	$ 12,080	$ 6,362	$ 22,222	$ 16,848
Income before cumulative effect of change in accounting principle, basic	$ 0.66	$ 0.35	$ 1.22	$ 0.86
Cumulative effect of change in accounting principle, basic	-	-	-	0.08
Net income per share, basic	$ 0.66	$ 0.35	$ 1.22	$ 0.94
Income before cumulative effect of change in accounting principle, diluted	$ 0.65	$ 0.35	$ 1.21	$ 0.86
Cumulative effect of change in accounting principle, diluted	-	-	-	0.08
Net income per share, diluted	$ 0.65	$ 0.35	$ 1.21	$ 0.94
Weighted average shares outstanding, basic	18,293	17,952	18,230	17,928
Weighted average shares outstanding, diluted	18,479	18,094	18,396	18,042

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)

	June 30, 2004	December 31, 2003
	(Unaudited)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 14,514	$ 18,008
Accounts receivable	32,679	31,789
Inventory	990	246
Prepaid expenses	6,675	1,018
Other	923	844
Total current assets	55,781	51,905
Property and equipment		
Oil and gas properties (successful efforts method)	551,878	503,290
Other property and equipment	274,397	272,447
Less: Accumulated depreciation, depletion and amortization	(177,281)	(149,934)
Net property and equipment	648,994	625,803
Other assets	5,173	6,025
Total assets	$ 709,948	$ 683,733
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 3,000	$ 1,500
Accounts payable	3,140	9,911
Accrued liabilities	20,193	19,153
Hedging liabilities	4,786	2,678
Taxes on income	1,943	-
Total current liabilities	33,062	33,242
Other liabilities	17,224	15,188
Hedging liabilities	1,677	998
Deferred income taxes	84,053	77,863
Long-term debt of the Company	63,000	64,000
Long-term debt of PVR	87,208	90,286
Minority interest in PVR	190,150	190,508
Shareholders' equity		
Preferred stock of $100 par value – authorized 100,000 shares; none issued	-	-
Common stock of $0.01 par value at June 30, 2004 and $6.25 at December 31, 2003 – 32,000,000 shares authorized; 18,356,544 and 18,104,832 shares issued and outstanding at June 30, 2004 and December 31, 2003, respectively (9,052,416 pre-split shares issued and outstanding at December 31, 2003)	184	56,576
Paid-in capital	76,460	14,497
Retained earnings	161,729	143,619
Accumulated other comprehensive income	(3,687)	(2,250)
	234,686	212,442
Less: Unearned compensation and ESOP	(1,112)	(794)
Total shareholders' equity	233,574	211,648
Total liabilities and shareholders' equity	$ 709,948	$ 683,733

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Cash flow from operating activities				
Net income	$12,080	$ 6,362	$22,222	$16,848
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	13,387	12,010	27,543	24,358
Minority interest	4,695	2,823	9,198	5,842
Deferred income taxes	4,423	3,498	6,964	6,135
Dry hole and unproved leasehold expense	964	1,080	2,646	1,608
Cumulative effect of change in accounting principle	-	-	-	(1,363)
Other	1,086	449	2,136	955
Changes in operating assets and liabilities:				
Accounts receivable	(4,863)	693	(890)	(11,679)
Other current assets	(2,046)	250	(6,401)	(245)
Accounts payable and accrued expenses	3,557	1,675	(6,720)	5,001
Other assets and liabilities	772	296	1,901	509
Net cash provided by operating activities	34,055	29,136	58,599	47,969
Cash flow from investing activities				
Additions to property and equipment	(34,114)	(25,610)	(49,629)	(75,107)
Other	95	145	623	311
Net cash used in investing activities	(34,019)	(25,465)	(49,006)	(74,796)
Cash flow from financing activities				
Dividends paid	(2,060)	(2,025)	(4,111)	(4,038)
Distributions paid to minority interest holders of PVR	(5,351)	(5,329)	(10,779)	(9,253)
Proceeds from borrowings of the Company	10,000	7,399	10,000	39,399
Repayments of borrowings of the Company	(2,000)	(2,032)	(11,000)	(2,084)
Proceeds from borrowings of PVR	-	-	-	90,000
Repayments of borrowings of PVR	(1,000)	-	(1,000)	(88,387)
Payments for debt issuance costs	-	-	-	(1,419)
Issuance of stock and other	1,863	703	3,803	1,184
Net cash provided by (used in) financing activities	1,452	(1,284)	(13,087)	25,402
Net increase (decrease) in cash and cash equivalents	1,488	2,387	(3,494)	(1,425)
Cash and cash equivalents - beginning of period	13,026	9,529	18,008	13,341
Cash and cash equivalents - end of period	$14,514	$11,916	$14,514	$11,916
Supplemental disclosures				
Cash paid during the periods for:				
Interest (net of amounts capitalized)	$ 157	$ 196	$ 3,016	$ 970
Income taxes	$ 3,302	$ 5,996	$ 3,609	$6,080
Noncash investing and financing activities				
Issuance of PVR units for acquisition	$ -	$ 4,969	$ 1,060	$4,969

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

PENN VIRGINIA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Unaudited

June 30, 2004

1. BASIS OF PRESENTATION

The accompanying unaudited consolidated financial statements include the accounts of Penn Virginia Corporation ("Penn Virginia", "PVA", the "Company", "we" or "our"), all wholly-owned subsidiaries of the Company, and Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR") of which we indirectly own the sole two percent general partner interest and an approximately 42.5 percent limited partner interest. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and Securities and Exchange Commission ("SEC") regulations. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation have been included. These financial statements should be read in conjunction with our consolidated financial statements and footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2003. Our accounting policies are consistent with those described in our Annual Report on Form 10-K for the year ended December 31, 2003. Please refer to such Form 10-K for further discussion of those policies. Operating results for the six months ended June 30, 2004 are not necessarily indicative of the results that may be expected for the year ended December 31, 2004. Certain reclassifications have been made to conform to the current period's presentation.

2. STOCK-BASED COMPENSATION

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Net income, as reported	$ 12,080	$ 6,362	$ 22,222	$ 16,848
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	149	169	217	224
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(303)	(355)	(540)	(633)
Pro forma net income	$ 11,926	$ 6,176	$ 21,899	$ 16,439
Earnings per share				
Basic - as reported	$ 0.66	$ 0.35	$ 1.22	$ 0.94
Basic - pro forma	$ 0.65	$ 0.34	$ 1.20	$ 0.92
Diluted - as reported	$ 0.65	$ 0.35	$ 1.21	$ 0.94
Diluted - pro forma	$ 0.65	$ 0.34	$ 1.19	$ 0.91

3. ASSET RETIREMENT OBLIGATIONS

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

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

Below is a reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligations as of June 30, 2004 (in thousands).

Balance, January 1, 2004	$ 3,389
Liabilities incurred in the current period	174
Liabilities settled in the current period	(98)
Accretion expense	108
Balance, June 30, 2004	$ 3,573

4. HEDGING ACTIVITIES

Commodity Cash Flow Hedges

The fair values of our hedging instruments are determined based on third party forward price quotes for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of June 30, 2004. The following table sets forth our positions as of June 30, 2004:

Time Period	Notional Quantities	Effective Floor /Ceiling Price	Swap Price	Fair Value
Natural Gas	**(Average MMbtu per Day)**	**($ Per MMbtu)**	**($ Per MMbtu)**	**(in thousands)**
Costless collars				
July 1 – July 31, 2004	4,000	$3.72 / $6.97		$ -
July 1 – October 31, 2004	3,000	$4.50 / $6.95		(25)
November 1 – December 31, 2004	6,000	$4.50 / $6.95		(158)
July 1 – November 30, 2004	6,500	$4.00 / $6.87		(137)
July 1 – October 31, 2004	7,000	$4.00 / $5.24		(836)
August 1 – October 31, 2004	4,000	$4.00 / $5.25		(363)
November 2004	5,000	$4.00 / $6.82		(58)
December 2004	11,500	$4.00 / $6.82		(211)
January 2005	11,000	$4.00 / $6.82		(276)
November 1, 2004 – January 31, 2005	2,000	$4.00 / $6.40		(146)
February 1, 2005 – April 30, 2005	14,000	$4.00 / $6.40		(1,035)
January 1, 2005 – March 31, 2005	3,000	$5.00 / $8.10		(81)
May 1, 2005 – September 30, 2005	8,000	$4.50 / $6.13		(632)
May 1, 2005 – September 30, 2005	5,000	$5.00 / $7.65		(11)
October 1, 2005 – January 31, 2006	12,000	$5.00 / $9.28		75
Swaps				
July 1 2004 – January 31, 2005	1,272		$4.70	(453)
Crude Oil	**(Average Bbls per Day)**		**($ Per barrel)**	
Swaps				
July 1, 2004 – December 31, 2004	75		$32.17	(77)
July 1, 2004 – January 31, 2005	350		$30.59	(526)
July 1, 2004 – January 31, 2005	60		$26.93	(146)
Total				$ (5,096)

Based upon our assessment of our derivative contracts designated as cash flow hedges at June 30, 2004, we reported (i) a net hedging liability of approximately $5.1 million and (ii) a loss in accumulated other comprehensive income of $3.3 million, net of a related income tax benefit of $1.8 million. In connection with monthly settlements, we recognized net hedging losses in natural gas and oil revenues of $1.2 million and $2.5 million for the three months and six months ended June 30, 2004, respectively. Based upon future oil and natural gas prices as of June 30, 2004, $4.8 million of hedging losses are expected to be realized within the next 12 months. The amounts that we ultimately realize will vary due to changes in the fair value of the open derivative contracts prior to settlement. We recognized net hedging losses of $1.4 million and $5.5 million for the three months and six months ended June 30, 2003, respectively.

Interest Rate Swap

In connection with its senior unsecured notes, PVR entered into an interest rate swap agreement with a notional amount of $30 million to hedge a portion of the fair value of those notes which mature over a ten-year period. This swap was designated as a fair value hedge and has been reflected as a decrease of long-term debt of approximately $1.3 million as of June 30, 2004, with a corresponding increase in long-term hedging liabilities. Under the terms of the interest rate swap agreement, the counterparty pays PVR a fixed annual rate of 5.77 percent on a total notional amount of $30 million, and PVR pays the counterparty a variable rate equal to the floating interest rate which is based on the six month London Interbank Offering Rate plus 2.36 percent.

5. LONG-TERM DEBT

At June 30, 2004 and December 31, 2003, long-term debt consisted of the following (in thousands):

	June 30, 2004 (Unaudited)	December 31, 2003
Penn Virginia revolving credit facility	$ 63,000	$ 64,000
PVR senior unsecured notes*	88,708	89,286
PVR revolving credit facility	1,500	2,500
	153,208	155,786
Less: Current maturities	(3,000)	(1,500)
	$ 150,208	$ 154,286

* Includes negative fair value adjustments of $1.3 million and $0.7 million related to interest rate swap designated as a fair value hedge as of June 30, 2004 and December 31, 2003, respectively.

6. COMMITMENTS AND CONTINGENCIES

Legal

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

Data Licensing Agreement

In November 2003, we purchased from a provider of seismic data a license to access 5,000 square miles of 3-D seismic data over the next two years. We paid $5 million in the first quarter of 2004. As of June 30, 2004, $3.6 million, representing prepaid license fees, was recorded in other current assets. Such amounts are expensed as data is received. We have a remaining commitment of $4 million to be paid in the first quarter of 2005.

Firm Transportation Agreements

In July 2004, we entered into a contract which provides firm transportation capacity rights on a pipeline system for ten years. The contract requires us to pay transportation demand charges regardless of the amount of pipeline capacity we use. Total minimum payments over the term of this contract will be approximately $11.6 million over the full ten-year period. All transportation costs, including demand charges, are expensed as they are incurred.

7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFITS

In accordance with SFAS No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits*, following are disclosures regarding the net periodic benefit costs recognized and the total amount of employer contributions.

The following table provides the components of net periodic benefit costs for the respective plans for the three months and six months ended June 30, 2004 and 2003 (in thousands):

	Pension				Post-retirement Healthcare			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003	2004	2003	2004	2003
Service cost	$ -	$ -	$ -	$ -	$ 6	$ 7	$ 12	$ 14
Interest cost	37	39	74	78	71	84	142	168
Amortization of prior service								
Amortization of prior service cost	1	2	2	4	22	26	44	52
Amortization of transitional								
Amortization of transitional obligation	1	1	2	2	-	-	-	-
Recognized actuarial (gain) loss	5	4	10	8	11	14	22	28
Net periodic benefit cost	$ 44	$ 46	$ 88	$ 92	$ 110	$ 131	$ 220	$ 262

Contributions paid during the three months and six months ended June 30, 2004 were $0.2 and $0.4 million, respectively. We expect to contribute a total of approximately $0.7 million to our pension and other postretirement benefit plans during 2004.

8. EARNINGS PER SHARE

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share for the three months and six months ended June 30, 2004 and 2003 (in thousands, except per share data).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Income before cumulative effect of change in accounting principle	$ 12,080	$ 6,362	$ 22,222	$ 15,485
Cumulative effect of change in accounting principle	-	-	-	1,363
Net income	$ 12,080	$ 6,362	$ 22,222	$ 16,848
Weighted average shares, basic	18,293	17,952	18,230	17,928
Effect of dilutive securities:				
Stock options	186	142	166	114
Weighted average shares, diluted	18,479	18,094	18,396	18,042
Income before cumulative effect of change in accounting principle, basic	$ 0.66	$ 0.35	$ 1.22	$ 0.86
Cumulative effect of change in accounting principle, basic	-	-	-	0.08
Net income per share, basic	$ 0.66	$ 0.35	$ 1.22	$ 0.94
Income before cumulative effect of change in accounting principle, diluted	$ 0.65	$ 0.35	$ 1.21	$ 0.86
Cumulative effect of change in accounting principle, diluted	-	-	-	0.08
Net income per share, diluted	$ 0.65	$ 0.35	$ 1.21	$ 0.94

9. STOCK SPLIT AND CHANGE IN PAR VALUE

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

10. COMPREHENSIVE INCOME

Comprehensive income represents changes in equity during the reporting period, including net income and charges directly to equity which are excluded from net income. For the three months and six months ended June 30, 2004 and 2003, the components of comprehensive income were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Net income	$ 12,080	$ 6,362	$ 22,222	$ 16,848
Unrealized holding losses on hedging activities, net of tax	(976)	(2,090)	(3,049)	(5,628)
Reclassification adjustment for hedging activities, net of tax	782	900	1,612	3,570
Comprehensive income	$ 11,886	$ 5,172	$ 20,785	$ 14,790

11. SEGMENT INFORMATION

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

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

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

Corporate and Other – primarily represents corporate functions.

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

	Oil and Gas	Coal Royalty and Land Management	Corporate and Other	Consolidated
	(in thousands)			
For the three months ended June 30, 2004:				
Revenues	$ 35,518	$18,732	$ 319	$ 54,569
Operating costs and expenses	9,076	4,264	2,177	15,517
Depreciation, depletion and amortization	8,426	4,852	109	13,387
Operating income (loss)	$ 18,016	$ 9,616	$(1,967)	$ 25,665
Interest expense				(1,464)
Interest income and other				258
Income before minority interest and taxes				$ 24,459
Total assets	$444,118	$258,722	$ 7,108	$ 709,948
For the three months ended June 30, 2003:				
Revenues	$ 30,208	$ 13,281	$ 214	$ 43,703
Operating costs and expenses	11,152	2,915	2,819	16,886
Depreciation, depletion and amortization	7,818	4,150	42	12,010
Operating income (loss)	$ 11,238	$ 6,216	$ (2,647)	14,807
Interest expense				(1,521)
Interest income				211
Income before minority interest and taxes				$ 13,497
Total assets	$381,508	$264,307	$ 6,493	$652,308

	Oil and Gas	Coal Royalty and Land Management	Corporate and Other	Consolidated
	(in thousands)			
For the six months ended June 30, 2004:				
Revenues	$ 72,999	$ 36,695	$ 501	$110,195
Operating costs and expenses	22,187	8,270	4,176	34,633
Depreciation, depletion and amortization	17,708	9,621	214	27,543
Operating income (loss)	$ 33,104	$ 18,804	$(3,889)	$ 48,019
Interest expense				(2,854)
Interest income and other				532
Income before minority interest and taxes				$ 45,697
Total assets	$ 444,118	$ 258,722	$7,108	$709,948
For the six months ended June 30, 2003:				
Revenues	$ 64,756	$ 26,522	$ 441	$ 91,719
Operating costs and expenses	22,401	5,862	5,478	33,741
Depreciation, depletion and amortization	15,921	8,368	69	24,358
Operating income (loss)	$ 26,434	$ 12,292	$(5,106)	33,620
Interest expense				(2,457)
Interest income				650
Income before minority interest and taxes				$ 31,813
Total assets	$381,508	$264,307	$ 6,493	$652,308

12. RECENT ACCOUNTING PRONOUNCEMENTS

As previously disclosed in our 2003 Form 10-K, a reporting issue existed regarding the application of certain provisions of SFAS No. 141, *Business Combinations* and SFAS No. 142, *Goodwill and Other Intangible Assets*, to companies in the extractive industries, including oil and gas and coal industry companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights as intangible assets in the balance sheet, apart from other capitalized oil and gas property and coal property costs, and provide specific footnote disclosures. In April 2004, the FASB issued a FASB Staff Position ("FSP") that amends certain sections of SFAS No. 141 and No. 142 relating to the characterization of coal mineral rights. The FSP is effective for the first reporting period beginning after April 29, 2004. As allowed by the FSP, the Partnership early adopted the FSP in April 2004 and, accordingly, reclassified its leased coal mineral rights back to tangible property. The Partnership discontinued straight-line amortization upon adoption and will deplete its coal mineral rights using the units-of-production method on a prospective basis. The amount capitalized related to a mineral right represents its fair value at the time such right was acquired, less accumulated amortization. Pursuant to the FSP, for comparative presentation purposes, $4.9 million was reclassified from other noncurrent assets to net property and equipment as of December 31, 2003 on the accompanying consolidated balance sheet.

In July 2004, the Financial Accounting Standards Board proposed another FSP that would clarify that the scope exception in paragraph 8(b) of SFAS No. 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing companies. Therefore, our historical practice of including the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties under SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies,* would be affirmed by the proposed FSP if adopted by the FASB.

The FASB issued FSP SFAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003,* in May 2004. The FSP requires employers that qualify for a prescription-drug subsidy under Medicare legislation enacted in December 2003 to recognize the reduction in costs as employees provide services in future years. This new accounting guidance is effective for reporting periods beginning after June 15, 2004, and we will adopt the FSP in the third quarter. The effect of the adoption on our financial position and results of operations is not yet known.

13. SUBSEQUENT EVENTS

Joint Venture Acquisition. In July 2004, the Partnership acquired from affiliates of Massey Energy Company a 50 percent interest in a joint venture formed to own and operate end-user coal handling facilities. The purchase price was approximately $28.5 million and was funded through the Partnership's credit facility. The equity method will be used to account for the investment in the joint venture, which had existing operations as of July 1, 2004, the effective date of the acquisition.

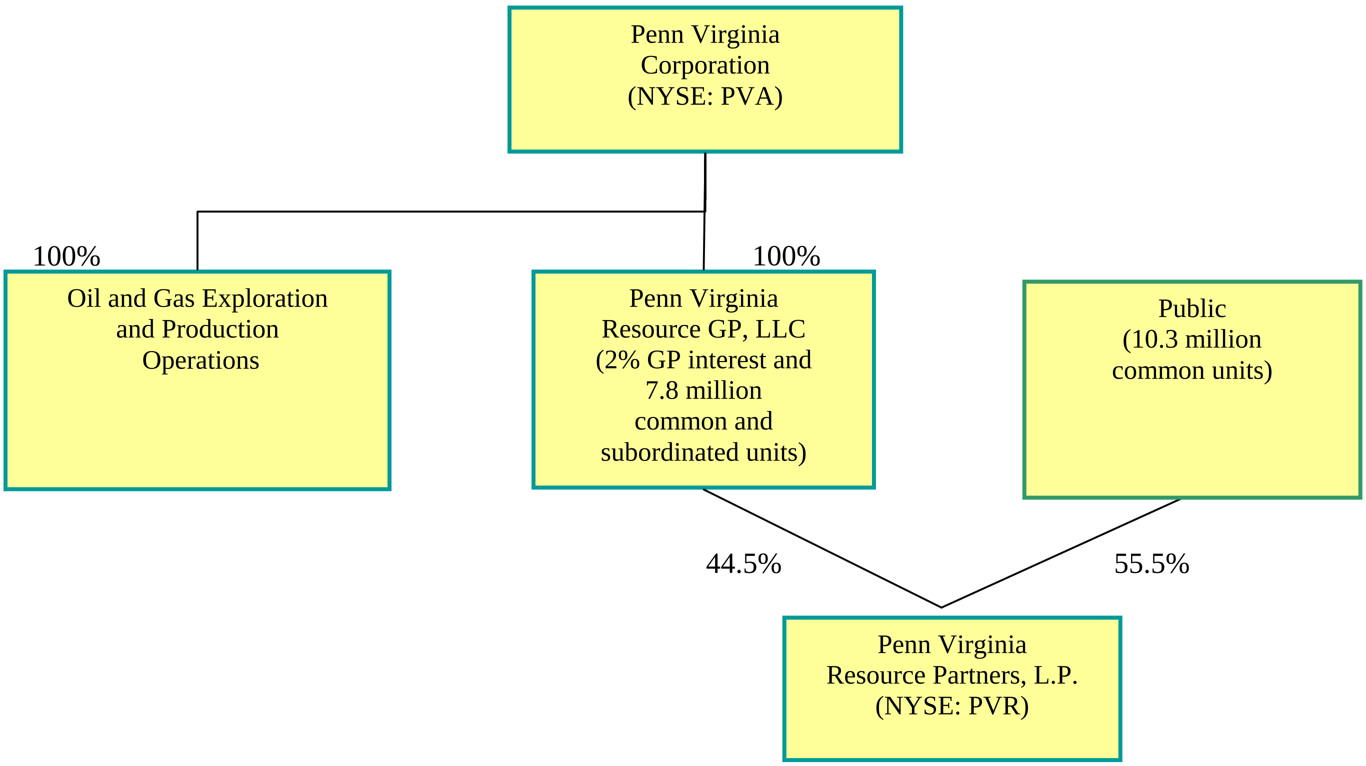
Dividend Declared. In July 2004, the Company declared a quarterly dividend of $0.1125 per share payable September 1, 2004 to shareholders of record on August 11, 2004.

Item 2. Management's Discussion and Analysis of Financial Conditions and Results of Operations

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

Overview

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



As a result of our ownership in the Partnership, we receive cash payments from PVR in the form of quarterly cash distributions. We received approximately $4.2 million and $8.5 million of cash distributions during the three months and six months ended June 30, 2004, respectively. We received approximately $4.2 million and $8.3 million in the three months and six months ended June 30, 2003, respectively. As part of our ownership of PVR's general partner, we also own the rights, referred to as incentive distribution rights, to receive an increasing percentage of quarterly distributions of available cash from operating surplus after certain levels of cash distributions have been achieved. As of June 30, 2004, these levels had not yet been achieved.

We are committed to increasing value to our shareholders by conducting a balanced program of investment in our two business segments. In the oil and gas segment, we expect to execute a program combining relatively low risk, moderate return development drilling in the Appalachian region of Virginia and West Virginia with higher risk, higher return exploration and development drilling in the onshore Gulf Coast, supplemented periodically with acquisitions. In addition to our continuing conventional development program, we are expanding our eastern presence by developing coalbed methane ("CBM") gas reserves in Appalachia. By employing horizontal drilling techniques, we expect to increase the value of the CBM reserves we own.

In the coal royalty and land management segment, PVR regularly evaluates acquisition opportunities that are accretive to cash available for distribution to PVR unitholders, of which we are the largest single unitholder. These opportunities include, but are not limited to, acquiring additional coal properties and reserves, acquiring or constructing assets for coal services which would provide a fee-based revenue stream, and acquiring mid-stream hydrocarbon-related transportation assets or other operating assets that would strategically fit within the Partnership.

Our oil and gas capital expenditures for 2004 are now expected to be between $115 million and $120 million, up from a range of $110 million to $115 million disclosed in the Company's previous guidance issued in May 2004 and compared to $100 million in our original 2004 capital expenditures budget. The increase is primarily due to increased drilling and pipeline construction expenditures to support CBM production in Appalachia and increased expenditures to expand the Company's Cotton Valley program in east Texas and north Louisiana. Borrowings under our credit facility were $63 million out of $150 million available as of June 30, 2004, and we expect to fund our 2004 capital expenditures with a combination of internal cash flow and credit facility borrowings.

Coal-related capital expenditures in 2004 are expected to be less than $1.0 million on existing properties excluding the joint venture acquisition discussed in Note 13 to the Consolidated Financial Statements. As of June 30, 2004, PVR had borrowed $90.2 million under its debt facilities. We expect to fund the 2004 capital expenditures for PVR through a combination of internal cash flow and credit facility borrowings.

Three Months Ended June 30, 2004 Performance – Oil and Gas Segment

During the second quarter of 2004, oil and gas production was 5.9 billion cubic feet equivalent (Bcfe), a one percent increase over the 5.8 Bcfe produced in the second quarter of 2003. The Company's active drilling program in Mississippi, horizontal CBM drilling in Appalachia, discoveries and field extensions in the Stella, south Creole and Broussard fields in south Louisiana and developmental drilling at the Company's Bethany joint venture in east Texas have increased production. This production increase was offset by pipeline curtailments by two of the Company's natural gas transporters in the Appalachian production areas along with natural field declines. Average daily oil and gas production increased slightly to 64.4 million cubic feet equivalent (MMcfe) in the second quarter of 2004 compared to 64.0 MMcfe in the second quarter of 2003.

Six Months Ended June 30, 2004 Performance – Oil and Gas Segment

In the first half of 2004, oil and gas production was 12.3 Bcfe, an increase of six percent over the 11.6 Bcfe reported for the same period in 2003. The increase in year-to-date production was primarily due to new drilling in the Company's Selma Chalk fields in Mississippi and its horizontal CBM drilling project in Appalachia. Considering the impact of the pipeline curtailments mentioned above and Gulf Coast drilling program delays, the Company now expects full-year 2004 production to range from 25.5 Bcfe to 26.7 Bcfe.

Three Months Ended June 30, 2004 Performance – Coal Royalty and Land Management Segment (PVR)

During the second quarter of 2004, coal royalty revenues were $17.5 million compared with $12.2 million for the second quarter of 2003, an increase of 43 percent. Production by PVR lessees increased by 1.3 million tons, or 20 percent, to 7.9 million tons in the second quarter of 2004 from 6.6 million tons in the second quarter of 2003. A significant part of this increase was attributed to increased production from a longwall mining operation located on PVR's Coal River property. Average royalties per ton increased to $2.21 in the second quarter of 2004 from $1.86 in the comparable 2003 period, primarily due to stronger market conditions for coal resulting in higher prices for coal sold by lessees and increased production from two lessees with higher royalty rates, partially offset by decreased production from PVR's New Mexico property.

Six Months Ended June 30, 2004 Performance – Coal Royalty and Land Management Segment (PVR)

In the first half of 2004, coal royalty revenues were $34.4 million compared with $23.7 million for the first half of 2003, an increase of 45 percent. Production by PVR lessees increased by 22 percent, to 15.9 million tons in the first half of 2004 from 13.0 million tons in the first half of 2003. A significant part of this increase was attributable to increased production from a longwall mining operation located on PVR's Coal River property. Average royalties per ton increased to $2.16 in the first half of 2004 from $1.82 in the comparable 2003 period. The increase in the average royalties per ton was primarily due to stronger market conditions for coal resulting in higher prices for coal sold by lessees and increased production from two lessees with higher royalty rates, partially offset by decreased production from PVR's New Mexico property.

Critical Accounting Policies and Estimates

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

Reserves. The estimates of oil and gas reserves are the single most critical estimate included in our financial statements. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities including projecting the total quantities in place, future production rates and the timing of future development. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

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

Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments and the fair value of properties subject to potential impairments.

There are several factors which could change our estimates of oil and gas reserves, including a change in economic limits resulting from a change in significant product prices and the use of reservoir decline rates different from those assumed when the reserves were initially recorded. Estimates of future production and development costs are also subject to change due to factors such as energy costs and the inflation or deflation of oil field service costs. Additionally, we perform impairment tests pursuant to Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* when significant events occur, such as a market move to a lower price environment or a material revision to our reserve estimates.

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

Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. The Partnership's estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively.

Oil and Gas Revenues. Oil and gas sales revenues are recognized when crude oil and natural gas volumes are produced and sold for our account. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, accruals for revenues and accounts receivable are made based on estimates of our share of production. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results will include estimates of production and revenues for the related time period. Any differences between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

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

Oil and Gas Properties. We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring and holding properties, costs of drilling successful exploration wells and development costs are capitalized. Annual lease rentals, exploration costs, geological, geophysical and seismic costs and exploratory dry-hole costs are expensed as incurred.

A portion of the carrying value of the Company's oil and gas properties is attributable to unproved properties. At June 30, 2004, the costs attributable to unproved properties were approximately $64.1 million. These costs are not currently being depreciated or depleted. As exploration work progresses and the reserves on these properties are proven, capitalized costs of the properties will be written off through depletion expense. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be expensed. The timing of any write downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Asset Retirement Obligations. In accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, we make estimates of the timing and future costs of plugging and abandoning wells. Estimated abandonment dates will be revised in the future based on changes to related economic lives, which vary with product prices and production costs. Estimated plugging costs may also be adjusted to reflect changing industry conditions. Increases in operating costs and decreases in product prices would increase the estimated amount of our plugging and

abandonment obligations and increase depletion expense. Our cash flows would not be affected until costs to plug and abandon were actually incurred.

Results of Operations
Selected Financial Data – Consolidated

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in thousands, except share data)		(in thousands, except share data)	
Revenues	$ 54,569	$ 43,703	$ 110,195	$ 91,719
Operating costs and expenses	$ 28,904	$ 28,896	$ 62,176	$ 58,099
Operating income	$ 25,665	$ 14,807	$ 48,019	$ 33,620
Net income	$ 12,080	$ 6,362	$ 22,222	$ 16,848
Earnings per share, basic	$ 0.66	$ 0.35	$ 1.22	$ 0.94
Earnings per share, diluted	$ 0.65	$ 0.35	$ 1.21	$ 0.94
Cash flow provided by operating activities	$ 34,055	$ 29,136	$ 58,599	$ 47,969

Included in net income for the six months ended June 30, 2003 was $1.4 million, or $0.08 per diluted share, related to the adoption of SFAS No. 143.

Oil and Gas Segment

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

Operations and Financial Summary – Oil and Gas Segment

The following table sets forth the Oil and Gas segment's revenues, operating expenses and operating statistics for the three months ended June 30, 2004 compared with the same period in 2003 (in thousands, except per unit amounts).

	Three Months Ended June 30,			
	2004		2003	
Production	**Amount**	**$ Per Unit ***	**Amount**	**$ Per Unit***
Natural gas (MMcf)	5,294		4,860	
Oil and condensate (MBbls)	94		161	
Total equivalent production (MMcfe)	5,858		5,826	
Revenues				
Natural gas	$ 32,444	$ 6.13	$ 25,904	$ 5.33
Oil and condensate	3,030	32.23	4,314	26.80
Other income	44		(10)	
Total revenues	35,518	6.06	30,208	5.19
Expenses				
Lease operating expenses	3,271	0.56	3,294	0.57
Exploration expenses	1,835	0.31	3,656	0.63
Taxes other than income	2,147	0.37	2,478	0.43
General and administrative	1,823	0.31	1,724	0.30
Depreciation and depletion	8,426	1.44	7,818	1.34
Total expenses	17,502	2.99	18,970	3.27
Income before income taxes	$ 18,016	$ 3.07	$ 11,238	$ 1.92
Revenue Summary				
Natural gas				
Revenue received for production	$ 33,189	$ 6.27	$ 27,243	$ 5.61
Effect of hedging activities	(745)	(0.14)	(1,339)	(0.28)
Net revenue realized	$ 32,444	$ 6.13	$ 25,904	$ 5.33
Crude oil and condensate				
Revenue received for production	$ 3,487	$ 37.09	$ 4,360	$ 27.09
Effect of hedging activities	(457)	(4.86)	(46)	(0.29)
Net revenue realized	$ 3,030	$ 32.23	$ 4,314	$ 26.80

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

Revenues. Oil and gas total revenues increased $5.3 million to $35.5 million in second quarter of 2004 from $30.2 million in the second quarter of 2003.

Increased crude oil and natural gas realized prices accounted for most of the $5.3 million increase in total oil and gas revenues from the second quarter of 2003 to the second quarter of 2004. Crude oil and natural gas production increased to 5.9 Bcfe in the second quarter of 2004, a one percent increase over the 5.8 Bcfe produced in the second quarter of 2003. The production increase was primarily due to the Company's active drilling program in Mississippi, horizontal CBM drilling in Appalachia, discoveries and field extensions in the Stella, south Creole and Broussard fields in south Louisiana and developmental drilling at the Company's Bethany joint venture in east Texas. These production increases were offset by pipeline curtailments in the Appalachian operating region and natural field declines.

Approximately 90 percent of our second quarter 2004 production was natural gas, for which the average realized price received was $6.13 per million cubic feet (Mcf) compared with $5.33 per Mcf in the second quarter of 2003, a 15 percent increase. The average realized oil price received was $32.23 per barrel for the second quarter of 2004, up 20 percent from $26.80 per barrel in the second quarter of 2003.

Gains and losses from hedging activities are included in revenues when the hedged production occurs. For the three months ended June 30, 2004, approximately 38 percent of our natural gas production was hedged, primarily using costless collars, at an average floor price of $3.80 per MMbtu and ceiling price of $5.98 per MMbtu.

Since actual cash market prices exceeded the average ceiling price of the costless collars, our price on the hedged natural gas production was limited to the ceiling price of the costless collar, and we recognized a loss on settled natural gas hedges of $0.7 million in the second quarter of 2004 compared to a loss of $1.3 million in the same quarter of 2003.

Approximately 55 percent of our second quarter 2004 crude oil production was hedged using fixed price swaps with an average price of $29.48 per barrel. Crude oil cash market prices were significantly higher than the swap price, resulting in a loss on settled crude oil hedges of $0.5 million in the second quarter of 2004 compared to a loss of less than $0.1 million in the same quarter of 2003.

See Note 4 (Hedging Activities) in the Notes to the Consolidated Financial Statements for details of costless collars and fixed price swaps.

Operating expenses. The Oil and Gas segment's aggregate operating costs and expenses for the second quarter of 2004 were $17.5 million, compared with $19.0 million for the same period in 2003, a decrease of $1.5 million, or eight percent. The decrease in operating costs and expenses primarily related to lower exploration expenses and taxes other than income (production taxes), partially offset by increased depreciation, depletion and amortization.

Exploration expenses for the three months ended June 30, 2004 and 2003 consisted of the following (in thousands):

	Three Months Ended June 30,	
	2004	**2003**
Unproved leasehold impairments	$ 948	$ 91
Seismic	781	2,253
Dry hole costs	16	989
Other	90	323
Total	$ 1,835	$ 3,656

Exploration expenses decreased to $1.8 million in the second quarter of 2004 from $3.7 million in the second quarter of 2003, primarily due to higher costs for seismic data acquisition and higher dry hole costs incurred in the second quarter of last year. These decreases were offset in part by increased unproved leasehold impairments due to expiring lease options in south Texas.

Taxes other than income in the second quarter of 2004 decreased to $2.1 million, or six percent of oil and gas revenues, from $2.5 million, or eight percent of oil and gas revenues, in the same quarter of 2003, primarily due to increased production from horizontal CBM wells that are exempt from severance tax during the initial years of production and from relatively higher production in states with lower effective severance tax rates.

Oil and gas depreciation, depletion and amortization ("DD&A") increased from $7.8 million in the second quarter of 2003 to $8.4 million in the second quarter of 2004, primarily due to an increase in the weighted average DD&A rate from $1.34 per Mcfe in the second quarter of 2003 to $1.44 per Mcfe in the second quarter of 2004. The increase in the weighted average DD&A rate was the result of a greater percentage of production coming from relatively higher cost horizontal CBM and Gulf Coast wells.

The following table sets forth the Oil and Gas segment's revenues, operating expenses and operating statistics for the six months ended June 30, 2004 compared with the same period in 2003 (in thousands, except per unit amounts).

	Six Months Ended June 30,			
	2004		2003	
Production	**Amount**	**$ Per Unit ***	**Amount**	**$ Per Unit ***
Natural gas (MMcf)	11,053		9,788	
Oil and condensate (MBbls)	210		310	
Total equivalent production (MMcfe)	12,313		11,648	
Revenues				
Natural gas	$ 66,408	$ 6.01	$ 55,904	$ 5.71
Oil and condensate	6,518	31.04	8,627	27.83
Other income	73		225	
Total revenues	72,999	5.93	64,756	5.56
Expenses				
Lease operating expenses	6,216	0.50	5,899	0.51
Exploration expenses	7,395	0.60	7,901	0.68
Taxes other than income	4,959	0.40	5,082	0.44
General and administrative	3,617	0.29	3,519	0.30
Depreciation and depletion	17,708	1.44	15,921	1.37
Total expenses	39,895	3.23	38,322	3.30
Income before income taxes	$ 33,104	$ 2.70	$ 26,434	$ 2.26
Revenue Summary				
Natural gas				
Revenue received for production	$ 68,171	$ 6.17	$ 61,021	$ 6.23
Effect of hedging activities	(1,763)	(0.16)	(5,117)	(0.52)
Net revenue realized	$ 66,408	$ 6.01	$ 55,904	$ 5.71
Crude oil and condensate				
Revenue received for production	$ 7,235	$ 34.45	$ 9,002	$ 29.04
Effect of hedging activities	(717)	(3.41)	(375)	(1.21)
Net revenue realized	$ 6,518	$ 31.04	$ 8,627	$ 27.83

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

Revenues. Oil and gas total revenues increased $8.2 million to $73.0 million for the six months ended June 30, 2004 from $64.8 million in the same period of 2003. The higher revenues resulted from increased prices realized for natural gas and crude oil along with increased natural gas production.

Crude oil and natural gas production increased to 12.3 Bcfe for the six months ended June 30, 2004, a six percent increase over the 11.6 Bcfe produced in the same period of 2003. The increase in year-to-date production was primarily due to new drilling in the Company's Selma Chalk fields in Mississippi and its horizontal CBM drilling project in Appalachia.

Approximately 90 percent of our production for the six months ended June 30, 2004 was natural gas, for which the average realized price received was $6.01 per Mcf compared with $5.71 per Mcf in the same period of 2003, a five percent increase. The average realized oil price received was $31.04 per barrel for the six months ended June 30, 2004, up 12 percent from $27.83 per barrel in the same period of 2003.

Gains and losses from hedging activities are included in revenues when the hedged production occurs. For the six months ended June 30, 2004, approximately 37 percent of our natural gas was hedged, primarily using costless collars, at an average floor price of $3.76 per MMbtu and ceiling price of $5.78 per MMbtu. During the same period of 2004, we hedged approximately 43 percent of our crude oil production using fixed price swaps with an average price of $29.20 per barrel. We recognized a loss on settled hedging activities of $2.5 million for the six months ended June 30, 2004 compared with a loss of $5.5 million in the same period of 2003.

See Note 4 (Hedging Activities) in the Notes to the Consolidated Financial Statements for details of costless collars and fixed price swaps.

Operating expenses. The Oil and Gas segment's aggregate operating costs and expenses for the six months ended June 30, 2004 were $39.9 million, compared with $38.3 million for the same period in 2003, an increase of $1.6 million, or four percent. The increase in operating costs and expenses primarily related to increased DD&A.

Exploration expenses for the six months ended June 30, 2004 and 2003 consisted of the following (in thousands):

	Six Months Ended June 30,	
	2004	**2003**
Unproved leasehold impairments	$ 2,207	$ 91
Seismic	4,577	5,896
Dry hole costs	439	1,517
Other	172	397
Total	$ 7,395	$ 7,901

Exploration expenses for the first six months of 2004 decreased to $7.4 million from $7.9 million in the same period of 2003, primarily due to lower costs for seismic data acquisition and lower dry hole costs, offset in part by increased unproved leasehold impairments primarily related to expiring lease options in south Texas.

Oil and gas DD&A increased from $15.9 million for the six months ended June 30, 2003 to $17.7 million in the same period of 2004 primarily due to higher production as discussed previously, and an increase in the weighted average DD&A rate from $1.37 per Mcfe for the six months ended June 30, 2003 to $1.44 per Mcfe in the same period of 2004. The increase in the weighted average DD&A rate was the result of a greater percentage of production coming from relatively higher cost horizontal CBM and Gulf Coast wells.

Coal Royalty and Land Management Segment (PVR)

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

The Partnership enters into leases with various third-party operators giving them the right to mine coal reserves on the Partnership's properties in exchange for royalty payments. Approximately 78 percent of the Partnership's coal royalty revenues for the first half of 2004 and 68 percent of its coal royalty revenues for the first half of 2003 were based on the higher of a percentage of the gross sales price or a fixed price per ton of coal sold, with pre-established minimum monthly or annual payments. The balance of the Partnership's coal royalty revenues for the respective periods were based on fixed royalty rates which escalate annually, also with pre-established monthly minimums. In addition to coal royalty revenues, the Partnership generates coal service revenues from fees charged to lessees for the use of coal preparation and transportation facilities. The Partnership also generates revenues from the sale of timber on its properties.

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

Operations and Financial Summary – Coal Royalty and Land Management Segment

The following table sets forth PVR's revenues, operating expenses and operating statistics for the three months ended June 30, 2004 compared with the same period in 2003.

Financial Highlights	Three Months Ended June 30, 2004	2003	Percentage Change
	(in thousands, except prices)		
Revenues			
Coal royalties	$ 17,517	$ 12,247	43%
Coal services	942	546	73%
Timber	142	193	(26%)
Other	131	295	(56%)
Total revenues	18,732	13,281	41%
Operating costs and expenses			
Operating	2,048	895	129%
Taxes other than income	230	293	(22%)
General and administrative	1,986	1,727	15%
Depreciation, depletion and amortization	4,852	4,150	17%
Total operating costs and expenses	9,116	7,065	29%
Operating income	9,616	6,216	55%
Interest expense	(1,403)	(1,371)	2%
Interest income	256	314	(18%)
Income before income taxes and minority interest	8,469	5,159	64%
Minority interest	4,695	2,823	66%
Income before income taxes	$ 3,774	$ 2,336	62%
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	7,941	6,600	20%
Average royalty per ton	$ 2.21	$ 1.86	19%

Revenues. PVR's revenues in the second quarter of 2004 were $18.7 million compared with $13.3 million for the same period in 2003, an increase of $5.4 million, or 41 percent. The increase in revenues primarily related to increased coal royalties received from PVR lessees.

Coal royalty revenues for the three months ended June 30, 2004 were $17.5 million compared with $12.2 million for the same period in 2003, an increase of $5.3 million, or 43 percent. Production by PVR's lessees increased by 1.3 million tons, or 20 percent, to 7.9 million tons in the second quarter of 2004 from 6.6 million tons in the second quarter of 2003. Average royalties per ton increased to $2.21 in the second quarter of 2004 from $1.86 in the comparable 2003 period. The increase in the average royalties per ton was primarily due to stronger market conditions for coal resulting in higher prices for coal sold by lessees and increased production from two lessees with higher royalty rates, offset in part by decreased production from PVR's New Mexico property.

Coal services revenues increased 73 percent to $0.9 million in the second quarter of 2004 from $0.5 million in the second quarter of 2003. The increase was primarily the result of start-up operations at two of PVR's coal loading facilities in July 2003 and February 2004.

Operating Costs and Expenses. The Partnership's aggregate operating costs and expenses for the second quarter of 2004 were $9.1 million, compared with $7.1 million for the same period in 2003, an increase of $2.0 million, or 29 percent. The increase in operating costs and expenses primarily related to increases in operating expenses and DD&A.

Operating expenses, which include royalty expenses and lease operating expenses, increased to $2.0 million in the second quarter of 2004 from $0.9 million in the second quarter of 2003. This increase was primarily due to higher royalty expense, which increased $1.4 million to $1.8 million in the second quarter of 2004 from $0.4 million the the second quarter of 2003. This increase was the result of higher production by lessees on subleased properties, which increased to 1.0 million tons in the second quarter of 2004 from 0.2 million tons in the second quarter of 2003.

DD&A for the three months ended June 30, 2004 was $4.9 million compared with $4.2 million for the same period of 2003, an increase of $0.7 million or 17 percent. This increase was a result of increased production by several of PVR's lessees over the comparable periods and depreciation on the two coal loading facilities which began start-up operations in July 2003 and February 2004. These increases were partially offset by a decline in production from the Partnership's New Mexico property, which has a higher cost basis.

Minority Interest. Minority interest was $4.7 million for the three months ended June 30, 2004 compared with $2.8 million for the same period in 2003, an increase of $1.9 million, or 66 percent. The increase was due to the increase in the Partnership's net income for the second quarter of 2004 compared with the second quarter of 2003.

The following table sets forth PVR's revenues, operating expenses and operating statistics for the six months ended June 30, 2004 compared with the same period in 2003.

	Six Months Ended June 30,		Percentage
Financial Highlights	**2004**	**2003**	**Change**
	(in thousands, except prices)		
Revenues			
Coal royalties	$ 34,377	$ 23,698	45%
Coal services	1,726	1,039	66%
Timber	295	749	(61%)
Other	297	1,036	(71%)
Total revenues	36,695	26,522	38%
Operating costs and expenses			
Operating	3,797	1,735	119%
Taxes other than income	514	589	(13%)
General and administrative	3,959	3,538	12%
Depreciation, depletion and amortization	9,621	8,368	15%
Total operating costs and expenses	17,891	14,230	26%
Operating income	18,804	12,292	53%
Interest expense	(2,732)	(2,156)	27%
Interest income	524	644	(19%)
Income before minority interest, income taxes and cumulative effect of change in accounting principle	16,596	10,780	54%
Minority interest	9,198	5,842	57%
Cumulative effect of change in accounting principle	-	107	-
Income before income taxes	$ 7,398	$ 4,831	53%
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	15,894	13,023	22%
Average royalty per ton	$ 2.16	$ 1.82	19%

Revenues. PVR's revenues in the first half of 2004 were $36.7 million compared with $26.5 million for the same period in 2003, an increase of $10.2 million, or 38 percent. The increase in revenues primarily related to increased coal royalties received from lessees.

Coal royalty revenues for the six months ended June 30, 2004 were $34.4 million compared with $23.7 million for the same period in 2003, an increase of $10.7 million, or 45 percent. Production by PVR's lessees increased by 2.9 million tons, or 22 percent, to 15.9 million tons in the first half of 2004 from 13.0 million tons in the first half of 2003. Average royalties per ton increased to $2.16 in the first half of 2004 from $1.82 in the comparable 2003 period. The increase in the average royalties per ton was primarily due to stronger market conditions for coal resulting in higher prices for coal sold by PVR's lessees and increased production from two lessees with higher royalty rates, offset by decreased production from the New Mexico property.

Coal services revenues increased 66 percent to $1.7 million in the first half of 2004 from $1.0 million in the first half of 2003, due primarily to the start-up of two of PVR's coal loading facilities in July 2003 and February 2004.

Other revenues decreased to $0.3 million in the first six months of 2004 from $1.0 million in the same period of 2003, primarily due to a decrease to zero of minimum rental revenues from $0.8 million in 2003's first half. All of PVR's lessees met their minimum production obligations during the first six months of 2004.

Operating Costs and Expenses. The Partnership's aggregate operating costs and expenses for the first half of 2004 were $17.9 million, compared with $14.2 million for the same period in 2003, an increase of $3.7 million, or 26 percent. The increase in operating costs and expenses primarily related to increases in operating expenses, general and administrative expenses and depreciation, depletion and amortization.

Operating expenses, which include royalty expenses and lease operating expenses, increased 119 percent to $3.8 million in the first half of 2004 from $1.7 million in the same period of 2003. This increase was primarily due to an increase in royalty expenses, offset in part by a decrease in lease operating expenses.

Royalty expenses were $3.4 million for the six months ended June 30, 2004 compared with $0.7 million for the six months ended June 30, 2003, an increase of $2.7 million. This increase was the result of an increase in production by lessees on two subleased properties. Production on these subleased properties increased 1.9 million tons to 2.3 million tons in the first half of 2004 from 0.4 million tons in the first half of 2003.

Lease operating expenses decreased 62 percent to $0.4 million in the first half of 2004 compared with $1.0 million in the same period of 2003. The Partnership incurred expenses of $0.6 million in the first half of 2003 to maintain idled mines on its West Coal River property, which is part of the Coal River property. These costs were assumed by a new lessee in May 2003.

General and administrative expenses increased $0.5 million, or 12 percent, to $4.0 million in the first half of 2004, from $3.5 million in the same period of 2003. Approximately $0.2 million was attributable to costs related to a secondary public offering for the sale of common units held by an affiliate of Peabody Energy Corporation. The remainder is primarily attributable to increased consulting fees used to evaluate acquisition opportunities and increased payroll due to the addition of employees.

DD&A for the six months ended June 30, 2004 was $9.6 million compared with $8.4 million for the same period of 2003, an increase of $1.2 million or 15 percent. This increase was a result of increased production by several of PVR's lessees over the comparable periods and depreciation on its two coal loading facilities which began start-up operations in July 2003 and February 2004. These increases were partially offset by a decline in production from the Partnership's New Mexico property, which has a higher cost basis.

Interest Expense. Interest expense was $2.7 million for the six months ended June 30, 2004 compared with $2.2 million for the same period in 2003, an increase of $0.5 million, or 27 percent. The increase was primarily due to the closing in March 2003 of a private placement of $90 million ten-year senior unsecured notes (the "Notes"), which bear interest at a fixed rate of 5.77 percent. Prior to the private placement, the $90 million was included on PVR's revolving credit facility, which bears interest at a relatively lower Eurodollar rate plus an applicable margin which ranges from 1.25 to 2.25 percent.

Minority Interest. Minority interest was $9.2 million for the six months ended June 30, 2004 compared with $5.8 million for the same period in 2003, an increase of $3.4 million, or 57 percent. The increase was due to the increase in the Partnership's net income for the second quarter of 2004 compared with the second quarter of 2003.

Corporate and Other Segment

The Corporate and Other segment primarily consists of oversight and administrative functions.

Operations and Financial Summary – Corporate and Other Segment

The following table sets forth the Corporate and Other segment's revenues, operating expenses and operating statistics for the three months ended June 30, 2004 compared with the same period in 2003.

	Three Months Ended June 30,	
	2004	2003
	(in thousands)	
Revenues		
Other	$ 319	$ 214
Total revenues	319	214
Expenses		
Lease operating	150	149
Taxes other than income	87	224
General and administrative	1,940	2,446
Depreciation, depletion and amortization	109	42
Total expenses	2,286	2,861
Operating loss	(1,967)	(2,647)
Interest expense	(61)	(150)
Interest income and other	2	(103)
Loss before income taxes	$ (2,026)	$ (2,900)

General and administrative (G&A) expenses decreased from $2.4 million in the second quarter of 2003 to $1.9 million in the same period of 2004. This $0.5 million decrease was primarily attributable to the absence in 2004 of consulting and advisory fees incurred in 2003 related to the consideration of various shareholder proposals, offset in part by a general increase in staffing levels and higher insurance premiums.

Interest costs were capitalized during the second quarters of 2004 and 2003 as activities related to unproved properties were in progress to bring projects to their intended use. Accordingly, we capitalized all direct credit facility interest costs, amounting to $0.4 million in each of the second quarters of 2004 and 2003. Interest costs which were expensed in the Corporate and Other segment related to the amortization of debt issuance costs.

The following table sets forth the Corporate and Other segment's revenues, operating expenses and operating statistics for the six months ended June 30, 2004 compared with the same period in 2003.

	Six Months Ended June 30,	
	2004	2003
	(in thousands)	
Revenues		
Other	$ 501	$ 441
Total revenues	501	441
Expenses		
Lease operating	300	300
Taxes other than income	21	397
General and administrative	3,855	4,781
Depreciation, depletion and amortization	214	69
Total expenses	4,390	5,547
Operating loss	(3,889)	(5,106)
Interest expense	(122)	(301)
Interest income and other	8	6
Loss before income taxes	$ (4,003)	$ (5,401)

G&A expenses decreased from $4.8 million for the six months ended June 30, 2003 to $3.9 million in the same period of 2004. This $0.9 million decrease was primarily attributable to the absence in 2004 of consulting and advisory fees incurred in 2003 related to the consideration of various shareholder proposals, offset in part by a general increase in staffing levels and higher insurance premiums.

Interest costs were capitalized during the six months ended June 30, 2004 and 2003, as activities related to unproved properties were in progress to bring projects to their intended use. Accordingly, we capitalized all direct credit facility interest costs, amounting to $0.9 million in the six months ended June 30, 2004 and 2003, respectively. Interest costs which were expensed in the Corporate and Other segment related to the amortization of debt issuance costs.

Capital Resources and Liquidity

The Company and PVR have separate credit facilities, and neither entity guarantees the debt of the other. Since PVR's initial public offering in October 2001, with the exception of cash distributions received by the Company from PVR, the cash needs of each entity have been met independently with a combination of operating cash flows, credit facility borrowings and, in the case of PVR's December 2002 acquisition of coal reserves from affiliates of Peabody Energy Corporation ("Peabody"), issuance of new partnership units. We expect that our cash needs and the cash needs of PVR will continue to be met independently of each other with a combination of these funding sources. Following are summarized cash flow statements for 2004 and 2003 consolidating the oil and gas (and corporate) and the coal royalty and land management (PVR) segments.

For the six months ended June 30, 2004 (amounts in thousands)	Oil and Gas, Corporate and Other Segments	Coal Royalty and Land Mgmt (PVR)	Consolidated
Cash flow from operating activities			
Net income	$ 17,717	$ 4,505	$ 22,222
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	29,443	19,044	48,487
Net change in operating assets and liabilities	(14,694)	2,584	(12,110)
Net cash provided by operating activities	32,466	26,133	58,599
Cash flow from investing activities			
Additions to property and equipment	(48,762)	(867)	(49,629)
Other	248	375	623
Net cash used in investing activities	(48,514)	(492)	(49,006)
Cash flow from financing activities			
PVA dividends paid	(4,111)	-	(4,111)
PVR distributions received (paid)	8,490	(19,269)	(10,779)
PVA debt proceeds	10,000	-	10,000
PVA debt repayments	(11,000)	-	(11,000)
PVR debt proceeds	-	-	-
PVR debt repayments	-	(1,000)	(1,000)
Issuance of stock and other	3,803	-	3,803
Net cash provided by (used in) financing activities	7,182	(20,269)	(13,087)
Net increase (decrease) in cash and cash equivalents	(8,866)	5,372	(3,494)
Cash and cash equivalents - beginning of period	8,942	9,066	18,008
Cash and cash equivalents - end of period	$ 76	$ 14,438	$ 14,514

For the six months ended June 30, 2003 (amounts in thousands)	Oil and Gas, Corporate and Other Segments	Coal Royalty and Land Mgmt (PVR)	Consolidated
Cash flow from operating activities			
Net income	$ 13,968	$ 2,880	$ 16,848
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	22,944	14,591	37,535
Net change in operating assets and liabilities	(8,312)	1,898	(6,414)
Net cash provided by operating activities	28,600	19,369	47,969
Cash flow from investing activities			
Additions to property and equipment	(73,661)	(1,446)	(75,107)
Other	16	295	311
Net cash used in investing activities	(73,645)	(1,151)	(74,796)
Cash flow from financing activities			
PVA dividends paid	(4,038)	-	(4,038)
PVR distributions received/(paid)	8,331	(17,584)	(9,253)
PVA debt proceeds	39,399	-	39,399
PVA debt repayments	(2,084)	-	(2,084)
PVR debt proceeds	-	90,000	90,000
PVR debt repayments	-	(88,387)	(88,387)
Issuance of stock and other	906	(1,141)	(235)
Net cash provided by (used in) financing activities	42,514	(17,112)	25,402
Net increase (decrease) in cash and cash equivalents	(2,531)	1,106	(1,425)
Cash and cash equivalents - beginning of period	3,721	9,620	13,341
Cash and cash equivalents - end of period	$ 1,190	$ 10,726	$ 11,916

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

Cash Flows from Operating Activities

Consolidated net cash provided from operating activities was $58.6 million for the six months ended June 30, 2004, compared with $48.0 million for the same period in 2003. The oil and gas and corporate segment's net cash provided by operations was $32.5 million for the six months ended June 30, 2004 compared with $28.6 million for the same period in 2003. This increase was primarily due to increased production of natural gas as a result of new drilling and higher prices. Cash in excess of working capital needs was used to help fund oil and gas capital expenditures in 2004. Cash provided by operations of the coal royalty and land management segment was $26.1 million for the six months ended June 30, 2004, compared with $19.4 million in the same period in 2003. The increase was due to both increased production and higher average royalty rates realized.

Cash Flows from Investing Activities

Consolidated net cash used in investing activities was $49.0 million for the six months ended June 30, 2004, compared with $74.8 million during the same period in 2003. During these periods, we used cash primarily for capital expenditures for oil and gas development and exploration activities and acquisitions of oil and gas properties.

Capital expenditures totaled $56.4 million for the six months ended June 30, 2004, compared with $80.5 million during the same period in 2003. The following table sets forth capital expenditures by segment, made during the periods indicated.

	Six Months Ended June 30,	
	2004	**2003**
	(in thousands)	
Oil and gas		
Development drilling	$ 35,142	$ 26,226
Exploratory drilling	3,992	4,115
Lease acquisitions *	6,028	39,924
Field projects	5,606	2,121
Seismic and other	4,720	6,293
Total	55,488	78,679
Coal royalty and land management (PVR)		
Lease acquisitions **	72	1,260
Support equipment and facilities	795	186
Total	867	1,446
Other	69	337
Total capital expenditures	$ 56,424	$ 80,462

* Includes $33.5 million to acquire proved oil and gas properties in south Texas in the first quarter of 2003.

** Excludes noncash expenditure of $1.1 million to acquire additional reserves on PVR's Northern Appalachia properties in exchange for 51,000 units, which had been held in escrow since December 2002 and were released to affiliates of Peabody Energy Corporation in the first quarter of 2004.

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

Oil and gas segment capital expenditures for 2004 are now expected to be between $115 million and $120 million, up from a range of $110 million to $115 million disclosed in the Company's previous guidance issued n May 2004 and compared to $98 million in our original capital expenditures budget. The increase in anticipated 2004 capital expenditures is primarily due to pipeline construction expenditures to support our increasing horizontal CBM production in Appalachia and increased expenditures to expand the Company's Cotton Valley program in east

Texas and north Louisiana. We continually review drilling and other capital expenditure plans and may continue to change these amounts based on industry conditions and the availability of capital. We believe our cash flow from operations and sources of debt financing are sufficient to fund our 2004 planned capital expenditures program as revised.

Cash Flows from Financing Activities

Consolidated net cash used in financing activities was $13.1 million for the six months ended June 30, 2004 compared with $25.4 million of cash provided from financing activities during the same period in 2003. During the six months ended June 30, 2004, we made net repayments of $1 million on our credit facility. Credit facility borrowings, net of repayments, provided approximately $37.3 million of cash in the six months ended June 30, 2003 and were used primarily to fund a south Texas acquisition. In the six months ended June 30, 2004 and 2003, we received $8.5 million and $8.3 million of cash distributions, respectively, from PVR. These distributions were primarily used for capital expenditure needs.

In July 2004, PVR announced a $0.02 per unit increase in its quarterly distribution payable August 13, 2004, to unitholders of record August 4, 2004, to $0.54 or $2.16 per unit on an annualized basis.

As of June 30, 2004, we had outstanding borrowings of $63 million under our $300 million revolving credit facility which has an initial commitment of $150 million and which can be expanded at our option to our current approved borrowing base of $200 million. The financial covenants in our credit agreements require us to maintain certain levels of debt-to-earnings and dividend limitation restrictions. We are currently in compliance with all of our covenants.

We have a $5 million line of credit, which had no borrowings against it as of June 30, 2004. The line of credit is effective through June 2005 and is renewable annually. The agreement was renewed in June 2004.

As of June 30, 2004, PVR had outstanding borrowings of $90.2 million, consisting of $1.5 million borrowed under its revolving credit facility and $90.0 million of the Notes, partially offset by $1.3 million fair value of the interest rate swap described below. The current portion of the Notes as of June 30, 2004 was $3.0 million.

In connection with the Notes, PVR entered into an interest rate swap agreement with a notional amount of $30 million, to effectively convert the interest rate on one-third of the Notes from a fixed rate to a floating rate. This swap is designated as a fair value hedge and has been reflected as a decrease in long-term debt of $1.3 million as of June 30, 2004 with a corresponding increase in long-term hedging liabilities. Under the terms of the interest rate swap agreement, the counterparty pays the Partnership a fixed annual rate of 5.77 percent on a total notional amount of $30 million, and the Partnership pays the counterparty a variable rate equal to the floating interest rate which is determined semi-annually and is based on the six month London Interbank Offering Rate ("LIBOR") plus 2.36 percent.

Future Capital Needs and Commitments. For the remainder of 2004, we anticipate making total capital expenditures, excluding future acquisitions, of approximately $90 million. Approximately $60 million of these expenditures are expected to be made in our oil and gas segment and are expected to be funded primarily by operating cash flow. Additional funding will be provided as needed from our credit facility, under which we had $87 million of borrowing capacity as of June 30, 2004. The credit facility can be expanded at our option to provide an additional $50 million of borrowing capacity. The remaining $30 million of anticipated 2004 capital expenditures is primarily due to PVR's July 2004 investment in a coal handling joint venture with Massey Energy Company, which was funded through PVR's credit facility.

On November 3, 2003, we purchased a license to access 5,000 square miles of 3-D seismic data over the next two years. We paid $5 million in the first quarter of 2004 and have a remaining commitment of $4 million to be paid in the first quarter of 2005.

In July 2004, we entered into a contract which provides firm transportation capacity rights on a pipeline system for ten years. The contract requires us to pay transportation demand charges regardless of the amount of pipeline capacity we use. Total minimum payments over the term of this contract will be approximately $11.6 million over the full ten-year period. All transportation costs, including demand charges, are expensed as they are incurred.

In our coal royalty and land management segment, PVR anticipates making total capital expenditures, excluding acquisitions, of approximately $0.1 million for coal services related projects for the remainder of 2004. Part of PVR's strategy is to make acquisitions which increase cash available for distribution to its unitholders. PVR's ability to make these acquisitions in the future will depend in part on the availability of debt financing and on its ability to periodically use equity financing through the issuance of new units. Since completing a large acquisition in late 2002, PVR's ability to incur additional debt has been restricted due to limitations in its debt instruments. After considering the effect of PVR's July 2004 investment in the joint venture with Massey Energy Company, PVR has approximately $17.4 million of borrowing capacity. This limitation may necessitate the issuance of new units by PVR, as opposed to using debt, to fund acquisitions in the future.

Environmental Matters

Our businesses are subject to various environmental hazards. Several federal, state and local laws, regulations and rules govern the environmental aspects of our businesses. Noncompliance with these laws, regulations and rules can result in substantial penalties or other liabilities. We do not believe our environmental risks are materially different from those of comparable companies nor that cost of compliance will have a material adverse effect on our profitability, capital expenditures, cash flows or competitive position. However, there is no assurance that future changes in or additions to laws, regulations or rules regarding the protection of the environment will not have such an impact. We believe we are in material compliance with environmental laws, regulations and rules.

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

Recent Accounting Pronouncements

As previously disclosed in our 2003 Form 10-K, a reporting issue existed regarding the application of certain provisions of SFAS No. 141, *Business Combinations* and SFAS No. 142, *Goodwill and Other Intangible Assets*, to companies in the extractive industries, including oil and gas and coal industry companies. The issue is whether SFAS N. 142 requires registrants to classify the costs of mineral rights as intangible assets in the balance sheet, apart from other capitalized oil and gas property and coal property costs, and provide specific footnote disclosures. In April 2004, the FASB issued a FASB Staff Position ("FSP") that amends certain sections of SFAS No. 141 and No. 142 relating to the characterization of coal mineral rights. The FSP is effective for the first reporting period beginning after April 29, 2004. As allowed by the FSP, the Partnership early adopted the FSP in April 2004 and, accordingly, reclassified its leased coal mineral rights back to tangible property. The Partnership discontinued straight-line amortization upon adoption and will deplete its coal mineral rights using the units-of-production method on a prospective basis. The amount capitalized related to a mineral right represents its fair value at the time such right was acquired, less accumulated amortization. Pursuant to the FSP, for comparative presentation purposes, $4.9 million was reclassified from other noncurrent assets to net property and equipment as of December 31, 2003 on the accompanying consolidated balance sheet.

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

The FASB issued FSP FAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*, in May 2004. The FSP requires employers that qualify for a prescription-drug subsidy under Medicare legislation enacted in December 2003 to recognize the reduction in costs as employees provide services in future years. This new accounting guidance is effective for reporting periods beginning after June 15, 2004. We will adopt the FSP in the third quarter, and the adoption is not expected to have a material effect on our financial position or results of operations.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Interest Rate Risk. At June 30, 2004, we had $63.0 million of long-term debt borrowed under our credit facility. The credit facility matures in December 2007 and is governed by a borrowing base calculation that is re-determined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.25 to 2.00 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin ranging from 0.30 to 0.50 percent. As a result, our 2004 interest costs will fluctuate based on short-term interest rates relating to the PVA credit facility.

As of June 30, 2004, $90 million of PVR's borrowings were financed with debt which has a fixed interest rate throughout its term. In connection with this financing, PVR executed an interest rate derivative transaction to effectively convert the interest rate on one-third of the amount financed from a fixed rate of 5.77 percent to a floating rate of LIBOR plus 2.36 percent. The interest rate swap has been accounted for as a fair value hedge in compliance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 137 and SFAS No. 138.

Price Risk Management. Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to mitigate the price risks associated with fluctuations in natural gas and crude oil prices as they relate to our anticipated production. These financial instruments are designated as cash flow hedges and accounted for in accordance with SFAS No. 133, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 139. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair value of our price risk management assets are significantly affected by energy price fluctuations. As of June 30, 2004, our open commodity price risk management positions on average daily volumes were as follows:

Natural gas hedging positions	**Costless Collars**			**Swaps**	
	Average MMbtu Per Day	Average Price / MMbtu (a) Floor	Average Price / MMbtu (a) Ceiling	Average MMbtu Per Day	Average Price /MMbtu
Third Quarter 2004	20,500	$ 4.05	$ 6.12	1,367	$ 4.70
Fourth Quarter 2004	19,837	$ 4.13	$ 6.54	1,234	$ 4.70
First Quarter 2005	16,656	$ 4.18	$ 6.80	379	$ 4.70
Second Quarter 2005	13,330	$ 4.45	$ 6.61	-	$ -
Third Quarter 2005	13,000	$ 4.69	$ 6.71	-	$ -
Fourth Quarter 2005	12,000	$ 5.00	$ 9.28	-	$ -
First Quarter 2006 (January only)	12,000	$ 5.00	$ 9.28	-	$ -

(a) The costless collar natural gas prices per MMbtu for each quarter include the effects of basis differentials, if any, that may be hedged.

Crude oil hedging positions	**Swaps**	
	Average Barrels Per Day	Average Price Per Barrel
Third Quarter 2004	488	$ 30.36
Fourth Quarter 2004	482	$ 30.41
First Quarter 2005 (January only)	400	$ 30.13

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. In addition, we and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

Such forward-looking statements may include, among other things, statements regarding development activities, capital expenditures, acquisitions and dispositions, drilling and exploration programs, expected commencement dates and projected quantities of oil, gas, or coal production, costs and expenditures as well as projected demand or supply for coal, coal handling joint venture operations, crude oil and natural gas, all of which may affect sales levels, prices, royalties and distributions realized by us and PVR.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and PVR and, therefore, involve a number of risks and uncertainties. We caution 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 our operations or financial condition to differ materially from those expressed or implied in the forward-looking statements include, but are not necessarily limited to:

* the cost of finding and successfully developing oil and gas reserves and the cost to PVR of finding new coal reserves;

* our ability to acquire new oil and gas reserves and PVR's ability to acquire new coal reserves on satisfactory terms;
* our ability to discover and economically produce proved oil and gas reserves on our unproved leasehold acreage;
* the price for which such reserves can be sold;
* the volatility of commodity prices for oil and gas and coal;
* our ability to obtain adequate pipeline transportation capacity for our oil and gas production;
* the operating ability and financial stability of our oil and gas joint ventures partners;
* PVR's ability to lease new and existing coal reserves;
* the ability of PVR's lessees to produce sufficient quantities of coal on an economic basis from PVR's reserves;
* the ability of lessees to obtain favorable contracts for coal produced from PVR's reserves;
* competition among producers in the oil and gas and coal industries generally;
* the extent to which the amount and quality of actual production differs from estimated recoverable proved oil and gas reserves and coal reserves;
* unanticipated geological problems;
* availability of required drilling rigs, materials and equipment;
* the occurrence of unusual weather or operating conditions including force majeure events;
* the failure of equipment or processes to operate in accordance with specifications or expectations;
* delays in anticipated start-up dates of our oil and natural gas production and PVR's lessees' mining operations and related coal infrastructure projects;
* environmental risks affecting the drilling and producing of oil and gas wells or the mining of coal reserves;
* the timing of receipt of necessary governmental permits by us and by PVR's lessees;
* the risks associated with having or not having price risk management programs;
* labor relations and costs;
* accidents;
* changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators;
* uncertainties relating to the outcome of litigation regarding permitting of the disposal of coal overburden;
* risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions;
* the experience and financial condition of lessees of PVR's coal reserves, including their ability to satisfy their royalty, environmental, reclamation and other obligations to PVR and others;
* coal handling joint venture operations;
* the Partnership's ability to make cash distributions;
* changes in financial market conditions; and
* other risk factors detailed in our SEC filings on Annual Report on Form 10-K.

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

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

Item 4. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures.

The Company, under the supervision and with the participation of its management, including its principal executive officer and principal financial officer, performed an evaluation of the design and operation of the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, the Company's principal executive officer and principal financial officer concluded that such disclosure controls and procedures are effective to ensure that material information relating to the Company, including its consolidated subsidiaries, is accumulated and communicated to the Company's management and made known to the principal executive officer and principal financial officer, particularly during the period for which this periodic report was being prepared.

(b) Changes in Internal Controls Over Financial Reporting.

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

PART II. Other Information

Items 1, 2, 3, 4 and 5 are not applicable and have been omitted.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

3 Articles of Amendment of Penn Virginia Corporation

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

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

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

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

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

(b) Reports on Form 8-K

The Company furnished a Form 8-K on May 5, 2004 announcing it issued a press release regarding its financial results for the three months ended March 31, 2004.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENN VIRGINIA CORPORATION

Date:	August 5, 2004	By:	/s/ Frank A. Pici Frank A. Pici Executive Vice President and Chief Financial Officer
Date:	August 5, 2004	By:	/s/ Dana G Wright Dana G Wright Vice President and Principal Accounting Officer

ARTICLES OF AMENDMENT OF
PENN VIRGINIA CORPORATION

The undersigned corporation, pursuant to Title 13.1, Chapter 9, Article 11 of the Code of Virginia, hereby executes the following articles of amendment and sets forth:

1. The name of the corporation is Penn Virginia Corporation.

2. The amendment adopted is to change each issued and unissued authorized share of Common Stock, $6.25 par value, effective at the close of business on June 3, 2004 to two shares of Common Stock, $0.01 par value.

3. The amendment was adopted on May 4, 2004 by the Board of Directors without shareholder action in accordance with Section 13.1-706 of the Code of Virginia. The Corporation has only shares of Common Stock, par value, $6.25 outstanding. The amendment will not result in any fractional issued or unissued shares.

4. Following the effectiveness of the amendment, the Corporation will have a total of 32,000,000 authorized shares of Common Stock, $0.01 par value

Executed in the name of the corporation by:

/s/ Nancy M. Snyder

Nancy Snyder
Senior Vice President, General Counsel
and Corporate Secretary

SCC corporate ID no.: 0016971-4

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

	1999	2000	2001	2002	2003	Six Months Ended June 30, 2004
Earnings						
Pre-tax income	$18,834	$59,230	$54,271	$29,705	$55,987	$44,846
Fixed charges	3,718	8,363	4,058	4,068	8,379	4,382
Total Earnings	**$22,552**	**$67,593**	**$58,329**	**$33,773**	**$64,366**	**$49,228**
Fixed Charges						
Interest expense	$ 3,298	$ 7,926	$ 3,596	$ 3,125	$ 7,352	$ 3,705
Rental Interest Factor	420	437	462	943	1,027	677
Total Fixed Charges	**$ 3,718**	**$ 8,363**	**$ 4,058**	**$ 4,068**	**$ 8,379**	**$ 4,382**
Ratio of Earnings to Fixed Charges	**6.1x**	**8.1x**	**14.4x**	**8.3x**	**7.7x**	**11.2x**

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

I, A. James Dearlove, President and Chief Executive Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this quarterly report on Form 10-Q of the Registrant;

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

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

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

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

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

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

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

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

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

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

Date: August 5, 2004

/s/ A. James Dearlove
A. James Dearlove
President and Chief Executive Officer

Exhibit 31.2

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

I, Frank A. Pici, Executive Vice President and Chief Financial Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this report on Form 10-Q of the Registrant;

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

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

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

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

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

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

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

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

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

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

Date: August 5, 2004

/s/ Frank A. Pici
Frank A. Pici
Executive Vice President and Chief Financial Officer

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

In connection with the Quarterly Report of Penn Virginia Corporation (the "Company") on Form 10-Q for the period ended June 30, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, A. James Dearlove, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: August 5, 2004

/s/ A. James Dearlove
A. James Dearlove
President and Chief Executive Officer

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

Exhibit 32.2

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

In connection with the Quarterly Report of Penn Virginia Corporation (the "Company") on Form 10-Q for the period ended June 30, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Pici, Executive Vice-President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: August 5, 2004

/s/ Frank A. Pici
Frank A. Pici
Executive Vice President and Chief Financial Officer

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