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, 2006

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: 1-16735

PENN VIRGINIA RESOURCE PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware	23-3087517
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

THREE RADNOR CORPORATE CENTER, SUITE 300
100 MATSONFORD ROAD
RADNOR, PA 19087
(Address of principal executive offices) (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.
[X] Yes [ ] No

Indicate by a check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
[ ] Yes [X] No

As of July 31, 2006, 33,994,650 common and 7,649,880 subordinated limited partner units were outstanding.

PENN VIRGINIA RESOURCE PARTNERS, L.P.

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PART I. FINANCIAL INFORMATION

Item 1 *Financial Statements*

PENN VIRGINIA RESOURCE PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME – unaudited
(in thousands, except per unit data)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Revenues				
Natural gas midstream	$ 95,350	$ 85,133	$ 204,531	$ 111,411
Coal royalties	24,254	20,129	46,676	38,182
Coal services	1,404	1,338	2,830	2,608
Other	2,455	3,009	4,590	3,598
Total revenues	123,463	109,609	258,627	155,799
Expenses				
Cost of midstream gas purchased	75,692	72,629	174,343	94,466
Operating	4,094	4,315	7,572	6,142
Taxes other than income	438	716	1,136	1,098
General and administrative	5,134	3,514	10,404	6,279
Depreciation, depletion and amortization	8,816	7,999	17,637	13,078
Total expenses	94,174	89,173	211,092	121,063
Operating income	29,289	20,436	47,535	34,736
Other income (expense)				
Interest expense, net	(4,139)	(2,743)	(7,912)	(5,578)
Derivatives	(11,929)	(828)	(18,062)	(14,764)
Net income	$ 13,221	$ 16,865	$ 21,561	$ 14,394
General partner's interest in net income	$ 902	$ 617	$ 1,412	$ 527
Limited partners' interest in net income	$ 12,319	$ 16,248	$ 20,149	$ 13,867
Basic and diluted net income per limited partner unit, common and subordinated	$ 0.30	$ 0.39	$ 0.48	$ 0.36
Weighted average number of units outstanding, basic and diluted:				
Common	33,994	29,734	33,994	27,484
Subordinated	7,650	11,474	7,650	11,474

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

PENN VIRGINIA RESOURCE PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(in thousands)

	June 30, 2006 (unaudited)	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 7,459	$ 23,193
Accounts receivable	56,973	76,398
Derivative assets	2,498	10,235
Other current assets	2,149	2,724
Total current assets	69,079	112,550
Property, plant and equipment	631,452	535,040
Accumulated depreciation, depletion and amortization	(91,304)	(76,258)
Net property, plant and equipment	540,148	458,782
Equity investments	24,644	26,672
Goodwill	7,718	7,718
Intangibles, net	35,518	38,051
Derivative assets	5,916	8,536
Other long-term assets	7,321	5,570
Total assets	$ 690,344	$ 657,879
Liabilities and Partners' Capital		
Current liabilities:		
Accounts payable and accrued liabilities	$ 48,952	$ 68,004
Current portion of long-term debt	9,820	8,108
Deferred income	7,340	5,073
Derivative liabilities	22,350	20,700
Total current liabilities	88,462	101,885
Deferred income	7,266	10,194
Other liabilities	3,725	3,749
Derivative liabilities	13,710	11,246
Long-term debt	306,730	246,846
Commitments and contingencies		
Partners' capital	270,451	283,959
Total liabilities and partners' capital	$ 690,344	$ 657,879

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

PENN VIRGINIA RESOURCE PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS - Unaudited
(in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Cash flows from operating activities				
Net income	$ 13,221	$ 16,865	$ 21,561	$ 14,394
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	8,816	7,999	17,637	13,078
Commodity derivative contracts:				
Total derivative losses	12,640	239	18,512	14,175
Cash settlements on derivatives	(5,139)	(1,251)	(8,061)	(1,251)
Non-cash interest expense	191	117	382	1,342
Equity earnings, net of distributions received	2,358	(246)	2,028	(544)
Changes in operating assets and liabilities	5,115	4,610	(1,540)	(1,416)
Net cash provided by operating activities	37,202	28,333	50,519	39,778
Cash flows from investing activities				
Acquisitions, net of cash acquired	(78,318)	(17,693)	(81,387)	(222,677)
Additions to property, plant and equipment	(9,825)	(5,531)	(15,321)	(5,820)
Other	3	-	3	52
Net cash used in investing activities	(88,140)	(23,224)	(96,705)	(228,445)
Cash flows from financing activities				
Distributions to partners	(15,524)	(13,267)	(31,048)	(23,678)
Proceeds from borrowings	64,800	15,000	64,800	226,800
Repayments of borrowings	-	(9,300)	(3,300)	(140,800)
Proceeds from issuance of partners' capital	-	1,276	-	129,006
Payments for debt issuance costs	-	-	-	(2,039)
Net cash provided by (used in) financing activities	49,276	(6,291)	30,452	189,289
Net increase (decrease) in cash and cash equivalents	(1,662)	(1,182)	(15,734)	622
Cash and cash equivalents – beginning of period	9,121	22,801	23,193	20,997
Cash and cash equivalents – end of period	$ 7,459	$ 21,619	$ 7,459	$ 21,619
Supplemental disclosure:				
Cash paid for interest	$ 3,511	$ 1,856	$ 8,863	$ 4,961

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

PENN VIRGINIA RESOURCE PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Unaudited
June 30, 2006

1. Nature of Operations

Penn Virginia Resource Partners, L.P. (the "Partnership," "we," "us" or "our") is a Delaware limited partnership formed by Penn Virginia Corporation ("Penn Virginia") in 2001 primarily to engage in the business of managing coal properties in the United States. Since the acquisition of a natural gas midstream business in March 2005, we conduct operations in two business segments: coal and natural gas midstream.

In our coal segment, we do not operate any mines. Instead, we enter into leases with various third-party operators which give those operators the right to mine coal reserves on our land in exchange for royalty payments. We also provide fee-based infrastructure facilities to some of our lessees and third parties to generate coal services revenues. These facilities include coal loading facilities, preparation plants and coal handling facilities located at end-user industrial plants. We also sell timber growing on our land.

We purchased our natural gas midstream business on March 3, 2005, through the acquisition of Cantera Gas Resources, LLC (the "Cantera Acquisition"). As a result of the Cantera Acquisition, we own and operate a significant set of midstream assets. Our natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services.

The general partner of the Partnership is Penn Virginia Resource GP, LLC, a wholly owned subsidiary of Penn Virginia. Penn Virginia recently formed Penn Virginia GP Holdings, L.P. ("GP Holdings"), a Delaware limited partnership. GP Holdings filed a Registration Statement on Form S-1 in July 2006 with the intent of completing an initial public offering of common units. GP Holdings was formed to own the general partner interest, all of the incentive distribution rights, 7,475,414 common units and 7,649,880 subordinated units in the Partnership. If the offering is completed, GP Holdings will use the proceeds from the offering to purchase newly issued class B common units from us, and we expect to use the proceeds from such purchase to repay debt outstanding under our revolving credit facility. The initial public offering of GP Holdings common units is not guaranteed to occur. Please refer to GP Holdings' Registration Statement on Form S-1 for more information on the potential initial public offering of GP Holdings common units.

2. Summary of Significant Accounting Policies

Our accounting policies are consistent with those described in our Annual Report on Form 10-K for the year ended December 31, 2005, except as discussed below. Please refer to such Form 10-K for a further discussion of those policies.

Basis of Presentation

The accompanying unaudited consolidated financial statements include the accounts of the Partnership and all wholly-owned subsidiaries. Intercompany balances and transactions have been eliminated in consolidation. 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 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 of the consolidated financial statements 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, 2005. Operating results for the six months ended June 30, 2006, are not necessarily indicative of the results that may be expected for the year ending December 31, 2006. Certain reclassifications have been made to conform to the current period's presentation.

Derivative Activities

Prior to January 1, 2006, all of our commodity derivative contracts were accounted for using hedge accounting in accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Effective January 1, 2006, our natural gas derivative contracts and certain NGL derivative contracts no longer qualified for hedge accounting. Effective May 1, 2006, we elected to discontinue hedge accounting prospectively for all remaining and future commodity derivatives. See Note 4 for further discussion of derivative activities and the discontinuation of hedge accounting.

3. Acquisitions

Huff Creek Acquisition

On May 25, 2006, we acquired from Huff Creek Energy Company and Appalachian Coal Holdings, Inc. the lease rights to approximately 69 million tons of coal reserves located on approximately 20,000 acres in Logan, Boone and Wyoming Counties, West Virginia. The purchase price was approximately $65 million and was funded with long-term debt under our revolving credit facility.

Transwestern Acquisition

On June 30, 2006, we completed the acquisition of approximately 115 miles of pipelines and related compression facilities in Texas and Oklahoma to complement our existing midstream systems (the "Transwestern Acquisition"). We paid for the acquisition with approximately $15 million in cash. In July 2006, we borrowed $15 million under our revolving credit facility to replenish the cash used in the Transwestern Acquisition.

4. Derivative Instruments

Discontinuation of Hedge Accounting

Because our natural gas derivatives and a large portion of our NGL derivatives no longer qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in oil and gas prices.

Natural Gas Midstream Segment Commodity Derivatives

We utilize swaps and costless collar derivative contracts to hedge against the variability in cash flows associated with forecasted natural gas midstream revenues and cost of gas purchased. While the use of these derivative instruments limits the risk of adverse price movements, their use also may limit future revenues or cost savings from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract. For a costless collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract.

The fair values of our derivative agreements are determined based on forward price quotes and regression analysis for the respective commodities as of June 30, 2006. The following table sets forth our positions as of June 30, 2006, for commodities related to natural gas midstream revenues (ethane, propane and crude oil) and cost of midstream gas purchased (natural gas):

	Average Volume Per Day	Weighted Average Price	Estimated Fair Value (in thousands)
Ethane Swaps	**(in gallons)**	**(per gallon)**	
Third Quarter 2006	81,480	$ 0.5038	$ (2,475)
Fourth Quarter 2006	73,126	$ 0.4870	(1,944)
First Quarter 2007 through Fourth Quarter 2007	34,440	$ 0.5050	(2,162)
First Quarter 2008 through Fourth Quarter 2008	34,440	$ 0.4700	(1,341)
Propane Swaps	**(in gallons)**	**(per gallon)**	
Third Quarter 2006	59,605	$ 0.7497	(2,935)
Fourth Quarter 2006	52,080	$ 0.7060	(2,348)
First Quarter 2007 through Fourth Quarter 2007	26,040	$ 0.7550	(3,383)
First Quarter 2008 through Fourth Quarter 2008	26,040	$ 0.7175	(3,038)
Crude Oil Swaps	**(in barrels)**	**(per barrel)**	
Third Quarter 2006 through Fourth Quarter 2006	1,100	$ 44.45	(7,057)
First Quarter 2007 through Fourth Quarter 2007	560	$ 50.80	(4,851)
First Quarter 2008 through Fourth Quarter 2008	560	$ 49.27	(4,454)
Crude Oil Collars	**(in barrels)**	**(per barrel)**	
Third Quarter 2006 through Fourth Quarter 2006 (October only)	270	$ 73.59	(41)
Natural Gas Swaps	**(in MMbtu)**	**(per MMbtu)**	
Third Quarter 2006	9,000	$ 6.86	(678)
Fourth Quarter 2006	8,005	$ 6.98	774
First Quarter 2007 through Fourth Quarter 2007	4,000	$ 6.97	3,056
First Quarter 2008 through Fourth Quarter 2008	4,000	$ 6.97	2,561
Natural gas midstream commodity derivatives			(30,316)
Interest rate swap			2,670
Total derivatives			$ (27,646)

Based upon the assessment of derivative agreements at June 30, 2006, we reported (i) a net derivative liability related to the natural gas midstream segment of $30.3 million, (ii) a loss in accumulated other comprehensive income of $11.6 million and (iii) a net loss on derivatives for hedge ineffectiveness of zero and $0.1 million for the three months and six months ended June 30, 2006, related to derivatives in the natural gas midstream segment. The following table summarizes the effects of commodity derivative activities on the accompanying consolidated statements of income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Income statement caption:				
Midstream revenue	$ (2,564)	$ 783	$ (4,732)	$ 783
Cost of gas purchased	1,853	(194)	4,282	(194)
Derivatives	(11,929)	(828)	(18,062)	(14,764)
Increase (decrease) in net income	$ (12,640)	$ (239)	$ (18,512)	$ (14,175)
Realized and unrealized derivative impact:				
Cash paid for derivative settlements	$ (5,139)	$ (1,251)	$ (8,061)	$ (1,251)
Unrealized derivative gain (loss)	(7,501)	1,012	(10,451)	(12,924)
Increase (decrease) in net income	$ (12,640)	$ (239)	$ (18,512)	$ (14,175)

At the time we entered into our natural gas derivatives and certain natural gas liquid ("NGL") derivatives, physical purchase prices of natural gas correlated well with NYMEX natural gas prices and physical sales prices of NGLs correlated well with NGL index prices. However, in the second half of 2005, basis differentials for certain derivative agreements widened as NYMEX natural gas prices and NGL index prices reached historically high levels. In the first quarter of 2006, our correlation assessment indicated that our NYMEX natural gas derivatives and certain NGL derivatives could no longer be considered "highly effective" hedges under the parameters of the accounting rules. Consequently, we discontinued hedge accounting effective January 1, 2006, for our natural gas derivatives and certain NGL derivatives that were no longer considered highly effective.

In November 2005, we entered into a basis swap for the period January 2006 through July 2006. The basis swap relates to purchases of natural gas in the Texas/Oklahoma Basin region. At June 30, 2006, the fair value of the basis swap asset was less than $0.1 million. During the three months and six months ended June 30, 2006, we recognized mark-to-market gains of $0.3 million and $0.7 million related to the basis swap. We have chosen not to designate this derivative as a hedge pursuant to SFAS No. 133. Therefore, in accordance with SFAS No. 133, changes in market value of the derivative instrument are charged to earnings. Mark-to-market gains are recorded in the derivatives line in the other income (expense) section of the accompanying consolidated statements of income.

Interest Rate Swaps

In September 2005, we entered into interest rate swap agreements to establish fixed rates on $60 million of the LIBOR-based portion of the outstanding balance on our revolving credit facility until March 2010 (the "Revolver Swaps"). We pay a weighted average fixed rate of 4.22 percent on the notional amount plus the applicable margin, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings as interest expense. We reported (i) a derivative asset of approximately $2.7 million at June 30, 2006, and (ii) a gain in accumulated other comprehensive income of $2.7 million at June 30, 2006, related to the Revolver Swaps. In connection with periodic settlements, we recognized $0.1 million and $0.2 million in net hedging gains in interest expense for the three months and six months ended June 30, 2006.

5. Partners' Capital and Distributions

Unit Split

On February 23, 2006, the board of directors of our general partner declared a two-for-one split of our common and subordinated units. To effect the split, we distributed one additional common unit and one additional subordinated unit (a total of 16,997,325 common units and 3,824,940 subordinated units) on April 4, 2006, for each common unit and subordinated unit held of record at the close of business on March 28, 2006. All units and per unit data have been retroactively adjusted to reflect the unit split.

Net Income per Limited Partner Unit

Net income per limited partner unit is based on the weighted average number of common and subordinated units outstanding during the period and is allocated in the same ratio as quarterly cash distributions are made. Net income per limited partner unit is computed by dividing the limited partners' interest in net income, after deducting our general partner's two percent interest and incentive distributions, by the weighted average number of limited partner units outstanding.

Cash Distributions

We make quarterly cash distributions of our available cash, generally defined as all of our cash and cash equivalents on hand at the end of each quarter less cash reserves established by our general partner at its sole discretion. According to our partnership agreement, our general partner receives incremental incentive cash distributions if cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly cash distribution per unit:		
First target – up to $0.275 per unit	98%	2%
Second target – above $0.275 per unit up to $0.325 per unit	85%	15%
Third target – above $0.325 per unit up to $0.375 per unit	75%	25%
Thereafter – above $0.375 per unit	50%	50%

The following table reflects the allocation of total cash distributions paid during the six months ended June 30, 2006 and 2005 (in thousands, except per unit information):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Limited partner units	$ 14,576	$ 12,781	$ 29,152	$ 22,949
General partner interest (2%)	298	231	595	434
Incentive distribution rights	650	255	1,301	295
Total cash distributions paid	$ 15,524	$ 13,267	$ 31,048	$ 23,678
Total cash distributions paid per unit	$ 0.3500	$ 0.3100	$ 0.7000	$ 0.5913

We paid quarterly distributions of $0.35 per unit in February 2006 and May 2006. In July 2006, we announced a $0.375 per unit distribution for the three months ended June 30, 2006, or $1.50 per unit on an annualized basis. The distribution will be paid on August 14, 2006, to unitholders of record at the close of business on August 4, 2006.

6. Related Party Transactions

General and Administrative

Penn Virginia charges us for certain corporate administrative expenses which are allocable to its subsidiaries. When allocating general corporate expenses, consideration is given to property and equipment, payroll and general corporate overhead. Any direct costs are paid by us. Total corporate administrative expenses charged to us totaled $1.1 million and $0.5 million for the three months ended June 30, 2006 and 2005, and $2.7 million and $0.9 million for the six months ended June 30, 2006 and 2005. These costs are reflected in general and administrative expenses in the accompanying consolidated statements of income. At least annually, management performs an analysis of general corporate expenses based on time allocations of shared employees and other pertinent factors. Based on this analysis, management believes the allocation methodologies used are reasonable.

Accounts Payable—Affiliate

Amounts payable to related parties totaled $2.3 million as of June 30, 2006. This balance consists primarily of amounts due to our general partner for general and administrative expenses incurred on our behalf and is included in accounts payable on the accompanying consolidated balance sheets.

7. Comprehensive Income

Comprehensive income represents changes in partners' capital during the reporting period, including net income and charges directly to partners' capital which are excluded from net income. Accumulated other comprehensive loss was $8.9 million at June 30, 2006. For the three months and six months ended June 30, 2006 and 2005, the components of comprehensive income were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Net income	$ 13,221	$ 16,865	$ 21,561	$ 14,394
Unrealized holding gains (losses) on derivative activities	(2,819)	1,621	(4,785)	(1,105)
Reclassification adjustment for derivative activities	604	(591)	764	(591)
Comprehensive income	$ 11,006	$ 17,895	$ 17,540	$ 12,698

8. Commitments and Contingencies

Legal

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

Environmental Compliance

The operations of our coal lessees and our natural gas midstream segment are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of our coal property leases impose liability for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. These lessees are bonded and have indemnified us against any and all future environmental liabilities. We regularly visit coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of our coal lessees and our natural gas midstream segment comply with existing regulations and does not expect any material impact on our financial condition or results of operations.

As of June 30, 2006, our environmental liabilities were $2.4 million, which represents our best estimate of our liabilities as of that date related to our coal and natural gas midstream businesses. We have reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

Mine Health and Safety Laws

There are numerous mine health and safety laws and regulations applicable to the coal mining industry. However, since we do not operate any mines and do not employ any coal miners, we are not subject to such laws and regulations. Accordingly, we have not accrued any related liabilities.

9. 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 our Chief Executive Officer and other senior officials. This group routinely reviews and makes operating and resource allocation decisions among our coal operations and our natural gas midstream operations. Accordingly, our reportable segments are as follows:

Coal

The coal segment includes:

- management of coal properties located in the Appalachian and Illinois Basin regions of the United States and in New Mexico;
- other land management activities such as selling standing timber and real estate rentals;
- fee-based infrastructure facilities leased to certain lessees; and
- our investment in a joint venture which primarily provides coal handling facilities to end-user industrial plants.

Natural Gas Midstream

The natural gas midstream segment derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services.

Segment Financial Information

The following table presents a summary of certain financial information relating to our segments (in thousands):

	Coal	Natural Gas Midstream	Consolidated
For the Three Months Ended June 30, 2006:			
Revenues	$ 27,898	$ 95,565	$ 123,463
Cost of midstream gas purchased	-	75,692	75,692
Operating costs and expenses	3,822	5,844	9,666
Depreciation, depletion and amortization	4,747	4,069	8,816
Operating income	$ 19,329	$ 9,960	29,289
Interest expense, net			(4,139)
Derivatives			(11,929)
Net income			$ 13,221
Total assets	$ 437,013	$ 253,331	$ 690,344
Additions to property and equipment	$ 69,163	$ 18,980	$ 88,143
For the Three Months Ended June 30, 2005:			
Revenues	$ 23,693	$ 85,916	$ 109,609
Cost of midstream gas purchased	-	72,629	72,629
Operating costs and expenses	3,063	5,482	8,545
Depreciation, depletion and amortization	4,328	3,671	7,999
Operating income	$ 16,302	$ 4,134	20,436
Interest expense, net			(2,743)
Derivatives			(828)
Net income			$ 16,865
Total assets	$ 288,278	$ 254,039	$ 542,317
Additions to property and equipment	$ 19,659	$ 3,565	$ 23,224

	Coal	Natural Gas Midstream (1)	Consolidated
For the Six Months Ended June 30, 2006:			
Revenues	$ 53,226	$ 205,401	$ 258,627
Cost of midstream gas purchased	-	174,343	174,343
Operating costs and expenses	7,331	11,781	19,112
Depreciation, depletion and amortization	9,499	8,138	17,637
Operating income	$ 36,396	$ 11,139	47,535
Interest expense, net			(7,912)
Derivatives			(18,062)
Net income			$ 21,561
Total assets	$ 437,013	$ 253,331	$ 690,344
Additions to property and equipment	$ 75,167	$ 21,541	$ 96,708
For the Six Months Ended June 30, 2005:			
Revenues	$ 43,507	$ 112,292	$ 155,799
Cost of midstream gas purchased	-	94,466	94,466
Operating costs and expenses	6,726	6,793	13,519
Depreciation, depletion and amortization	8,183	4,895	13,078
Operating income	$ 28,598	$ 6,138	34,736
Interest expense, net			(5,578)
Derivatives			(14,764)
Net income			$ 14,394
Total assets	$ 288,278	$ 254,039	$ 542,317
Additions to property and equipment	$ 29,031	$ 199,466	$ 228,497

(1) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.

Item 2 *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following review of the financial condition and results of operations of Penn Virginia Resource Partners, L.P. (the "Partnership," "we," "us" or "our") should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 1, "Financial Statements." Our discussion and analysis include the following items:

- Overview of Business
- Acquisitions and Investments
- Current Performance
- Critical Accounting Policies and Estimates
- Liquidity and Capital Resources
- Results of Operations
- Environmental
- Recent Accounting Pronouncements
- Forward-Looking Statements

Overview of Business

We are a publicly traded Delaware limited partnership formed by Penn Virginia Corporation ("Penn Virginia") in 2001 that is principally engaged in the management of coal properties and the gathering and processing of natural gas in the United States. Penn Virginia contributed its coal properties and related assets to us and, effective with the closing of our initial public offering in October 2001, our common units began trading publicly on the New York Stock Exchange under the symbol "PVR."

Both in our current limited partnership form and our previous corporate form, we have managed coal properties since 1882. Since the acquisition of a natural gas midstream business in March 2005, we conduct operations in two business segments: coal and natural gas midstream. A description of each of our reportable segments follows:

- Coal – 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.
- Natural Gas Midstream – gas processing, gathering and other related services.

We continually evaluate acquisition opportunities that are accretive to cash available for distribution to our unitholders. These opportunities include, but are not limited to, acquiring additional coal properties and reserves and acquiring or constructing assets for coal services and natural gas midstream gathering and processing, all of which would provide a primarily fee-based revenue stream.

Acquisitions and Investments

Huff Creek Acquisition

On May 25, 2006, we acquired from Huff Creek Energy Company and Appalachian Coal Holdings, Inc. the lease rights to approximately 69 million tons of coal reserves located on approximately 20,000 acres in Logan, Boone and Wyoming Counties, West Virginia (the "Huff Creek Acquisition"). The purchase price was approximately $65 million and was funded with long-term debt under our revolving credit facility.

Transwestern Acquisition

On June 30, 2006, we completed the acquisition of approximately 115 miles of pipelines and related compression facilities in Texas and Oklahoma to complement our existing midstream systems (the "Transwestern Acquisition"). We paid for the acquisition with approximately $15 million in cash. In July 2006, we borrowed $15 million under our revolving credit facility to replenish the cash used in the Transwestern Acquisition.

Coal Infrastructure Construction

We expect to complete construction and commence operation of a new 600-ton per hour coal processing plant and rail loading facility in the third quarter of 2006 for one of our lessees located in Knott County in eastern Kentucky. Since acquiring fee ownership and lease rights to the property's coal reserves in July 2005, we made cumulative capital expenditures of $7.7 million related to the construction of the facility as of June 30, 2006. Total capital expenditures for the construction are expected to be approximately $15 million.

Current Performance

Operating income for the six months ended June 30, 2006 was $47.9 million. The coal segment contributed $36.7 million, or 77 percent, to operating income, and the natural gas midstream segment contributed $11.2 million, or 23 percent. The following table presents a summary of certain financial information relating to our segments (in thousands):

	Coal	Natural Gas Midstream	Consolidated
For the Six Months Ended June 30, 2006:			
Revenues	$ 53,226	$ 205,401	$ 258,627
Cost of midstream gas purchased	-	174,343	174,343
Operating costs and expenses	7,331	11,781	19,112
Depreciation, depletion and amortization	9,499	8,138	17,637
Operating income	$ 36,396	$ 11,139	$ 47,535
For the Six Months Ended June 30, 2005:			
Revenues	$ 43,507	$ 112,292	$ 155,799
Cost of midstream gas purchased	-	94,466	94,466
Operating costs and expenses	6,726	6,793	13,519
Depreciation, depletion and amortization	8,183	4,895	13,078
Operating income	$ 28,598	$ 6,138	$ 34,736

Coal Segment

In the six months ended June 30, 2006, coal royalty revenues increased 22 percent, or $8.5 million, over the same period last year due to acquisitions, more coal being mined by our lessees and increasing coal prices. Tons produced by our lessees increased from 14.0 million tons in the six months ended June 30, 2005 to 15.7 million tons in the six months ended June 30, 2006, and our average gross royalties per ton increased from $2.73 in the six months ended June 30, 2005 to $2.98 in the six months ended June 30, 2006. The Illinois Basin coal reserves that we acquired in July 2005 resulted in $2.6 million of coal royalty revenues in the six months ended June 30, 2006. Generally, as coal prices increase, our average royalties per ton also increase because the vast majority of our lessees pay royalties based on the gross sales prices of the coal mined.

In managing our properties, we actively work with our lessees to develop efficient methods to exploit our reserves and to maximize production from our properties. We earn revenues from providing fee-based coal preparation and transportation services to our lessees, which enhance their production levels and generate additional coal royalty revenues, and from industrial third party coal end-users by owning and operating coal handling facilities through our joint venture with Massey Energy Company ("Massey"). Coal services revenues increased to $2.8 million in the six months ended June 30, 2006, from $2.6 million in the six months ended June 30, 2005. We believe that these types of fee-based infrastructure assets provide good investment and cash flow opportunities for us, and we continue to look for additional investments of this type, as well as other primarily fee-based assets. We also earn revenues from oil and gas royalty interests, coal transportation ("wheelage") rights and the sale of standing timber on our properties.

As of June 30, 2006, our primary coal reserves and coal infrastructure assets were located on the following properties:

- in central Appalachia, at properties in Buchanan, Lee and Wise Counties, Virginia; Floyd, Harlan, Knott and Letcher Counties, Kentucky; and Boone, Fayette, Kanawha, Lincoln, Logan, Raleigh and Wyoming Counties, West Virginia;
- in northern Appalachia, at properties in Barbour, Harrison, Lewis, Monongalia and Upshur Counties, West Virginia;
- in the Illinois Basin, at properties in Henderson and Webster Counties, Kentucky; and
- in the San Juan Basin, at properties in McKinley County, New Mexico.

Natural Gas Midstream Segment

The gross processing margin for our natural gas midstream operations increased from $16.9 million in the six months ended June 30, 2005 to $30.2 million in the six months ended June 30, 2006. This increase was due primarily to higher NGL prices. Inlet volumes at our gas processing plants and gathering systems were 137 million cubic feet ("MMcf") per day in the six months ended June 30, 2006, an increase over 126 MMcf per day in the six months ended June 30, 2005, primarily due to additional well connections in the area. As part of our risk management strategy, we use derivative financial instruments to hedge NGLs sold and natural gas purchased.

We continually seek new supplies of natural gas to both offset the natural declines in production from the wells currently connected to our systems and to increase throughput volume. New natural gas supplies are obtained for all of our systems by contracting for production from new wells, connecting new wells drilled on dedicated acreage and by contracting for natural gas that has been released from competitors' systems.

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 our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We consider the following to be the most critical accounting policies which involve the judgment of our management.

Natural Gas Midstream Revenues

Revenue from the sale of NGLs and residue gas is recognized when the NGLs and residue gas produced at our gas processing plants are sold. Gathering and transportation revenue is recognized based upon actual volumes delivered. Due to the time needed to gather information from various purchasers and measurement locations and then calculate volumes delivered, the collection of natural gas midstream revenues may take up to 30 days following the month of production. Therefore, accruals for revenues and accounts receivable and the related cost of midstream gas purchased and accounts payable are made based on estimates of natural gas purchased and NGLs and natural gas sold, and our financial results include estimates of production and revenues for the period of actual production. Any differences, which we do not expect to be significant, between the actual amounts ultimately received or paid and the original estimates are recorded in the period they become finalized. Approximately 39 percent of natural gas midstream revenues for the six months ended June 30, 2006, related to three customers.

Coal Royalty Revenues

Coal royalty revenues are recognized on the basis of tons of coal sold by our lessees and the corresponding revenues from those sales. Since we do not operate any coal mines, we do not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. Any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Derivative Instruments and Hedging Activities

We historically have entered into derivative financial instruments that would qualify for hedge accounting under Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Hedge accounting affects the timing of revenue recognition in our statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until the hedged transaction occurs. The results reflected in the statement of income are based on the actual settlements with the counterparty. We include this gain or loss in natural gas midstream revenues or cost of midstream gas purchased, depending on the commodity. Effective January 1, 2006, some of our derivatives did not qualify for hedge accounting under SFAS No. 133, and changes in market value of these derivative instruments were recognized in earnings. When we do not use hedge accounting, we could experience significant changes in the estimate of derivative gain or loss recognized in revenue and cost of midstream gas purchased due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

Because our natural gas derivatives and a large portion of our NGL derivatives no longer qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in oil and gas prices.

Depletion

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. Proven and probable reserves have been estimated by our own geologists and outside consultants. Our estimates of coal reserves are updated annually and may result in adjustments to coal reserves and depletion rates that are recognized prospectively.

Liquidity and Capital Resources

Since the closing of our initial public offering in October 2001, cash generated from operations and our borrowing capacity, supplemented by proceeds from the issuance of new common units, have been sufficient to meet our scheduled distributions, scheduled debt payments, working capital requirements and capital expenditures. Our primary cash requirements consist of quarterly distributions to our general partner and unitholders, normal operating expenses, interest and principal payments on our long-term debt and acquisitions of new assets or businesses. Summarized cash flow statements for the six months ended June 30, 2006 and 2005, consolidating our segments are set forth below (in millions):

For the six months ended June 30, 2006	Coal	Natural Gas Midstream	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 28.1	$ (6.5)	$ 21.6
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	11.9	18.6	30.5
Net change in operating assets and liabilities	(2.0)	0.5	(1.5)
Net cash provided by (used in) operating activities	$ 38.0	$ 12.6	50.6
Net cash used in investing activities	$ (75.2)	$ (21.5)	(96.7)
Net cash provided by financing activities			30.5
Net decrease in cash and cash equivalents			$ (15.6)

For the six months ended June 30, 2005	Coal	Natural Gas Midstream	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 22.9	$ (8.5)	$ 14.4
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	9.0	17.8	26.8
Net change in operating assets and liabilities	(11.2)	9.8	(1.4)
Net cash provided by (used in) operating activities	$ 20.7	$ 19.1	39.8
Net cash used in investing activities	$ (28.9)	$ (199.5)	(228.4)
Net cash provided by financing activities			189.3
Net increase in cash and cash equivalents			$ 0.7

Cash Flows

The overall increase in cash provided by operations for the six months ended June 30, 2006 compared to the same period of 2005 was primarily attributable to higher average gross coal royalties per ton and accretive cash flows from our natural gas midstream business, which was acquired in March 2005.

We made cash investments during the six months ended June 30, 2006, primarily for coal reserve acquisitions, coal loadout facility construction and natural gas midstream acquisitions and gathering system expansions. Cash investments in the same period of 2005 primarily included the acquisition of our natural gas midstream business, net of cash acquired, and coal reserve acquisitions.

Capital expenditures, including non-cash items, for the six months ended June 30, 2006 and 2005, were as follows:

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(in millions)	
Coal		
Acquisitions	$ 66.4	$ 24.7
Expansion capital expenditures	7.6	0.2
Other property and equipment expenditures	0.1	4.1
Total	74.1	29.0
Natural gas midstream		
Acquisitions, net of cash acquired	14.6	198.0
Expansion capital expenditures	3.4	1.5
Other property and equipment expenditures	4.3	-
Total	22.3	199.5
Total capital expenditures	$ 96.4	$ 228.5

We used cash flows from operations and our revolving credit facility to fund capital expenditures, including two acquisitions, for the six months ended June 30, 2006. To finance our acquisitions in the six months ended June 30, 2005, we borrowed $86.0 million, net of repayments, received proceeds of $126.4 million from our secondary public offering and received a $2.6 million contribution from our general partner. Distributions to partners increased to $31.0 million in the six months ended June 30, 2006, from $23.7 million in the six months ended June 30, 2005, because we increased the quarterly unit distribution.

Long-Term Debt

As of June 30, 2006, we had outstanding borrowings of $316.6 million, consisting of $236.9 million borrowed under our revolving credit facility and $79.7 million of senior unsecured notes (the “Notes”). The current portion of the Notes as of June 30, 2006, was $9.8 million.

Revolving Credit Facility. As of June 30, 2006, we had $236.9 million outstanding under our $300 million revolving credit facility (the “Revolver”) that matures in March 2010. The Revolver is available for general Partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. We have a one-time option to expand the Revolver by $150 million upon receipt by the credit facility’s administrative agent of commitments from one or more lenders. The Revolver’s interest rate fluctuates based on our ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 1.00 percent if we select the base rate borrowing option under the credit agreement or at a rate derived from the London Interbank Offering Rate (“LIBOR”) plus an applicable margin ranging from 1.00 percent to 2.00 percent if we select the LIBOR-based borrowing option.

The financial covenants under the Revolver require us to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted our additional borrowing capacity under the Revolver to $115.5 million as of June 30, 2006. Including the $15 million we borrowed in July 2006 to replenish cash used in the Transwestern Acquisition, our additional borrowing capacity is currently $100.5 million. At the current $300 million limit on the Revolver, and given our outstanding balance of $251.9 million including $15 million for the Transwestern Acquisition and net of letters of credit, we could borrow up to $46.5 million without exercising our one-time option to expand the Revolver. In order to utilize the full extent of the $100.5 million borrowing capacity, we would need to exercise our one-time option to expand the Revolver by $150 million. The Revolver prohibits us from making distributions to our unitholders and distributions in excess of available cash if any potential default or event of default occurs or would result from such unitholder distributions. In addition, the Revolver contains various covenants that limit, among other things, our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. As of June 30, 2006, we were in compliance with all of our covenants under the Revolver.

Senior Unsecured Notes. As of June 30, 2006, we owed $79.7 million under the Notes. The Notes bear interest at a fixed rate of 6.02 percent and mature over a ten-year period ending in March 2013, with semi-annual principal and interest payments. The Notes are equal in right of payment with all other unsecured indebtedness, including the Revolver. The Notes require us to obtain an annual confirmation of our credit rating, with a 1.00 percent increase in the interest rate payable on the Notes in the event our credit rating falls below investment grade. In March 2006, our investment grade credit rating was confirmed by Dominion Bond Rating Services. The Notes contain various covenants similar to those contained in the Revolver. As of June 30, 2006, we were in compliance with all of our covenants under the Notes.

Interest Rate Swaps. In September 2005, we entered into two interest rate swap agreements with notional amounts totaling $60 million to establish a fixed rate on the LIBOR-based portion of the outstanding balance of the Revolver until March 2010 (the "Revolver Swaps"). We pay a weighted average fixed rate of 4.22 percent on the notional amount plus the applicable margin, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings in interest expense. After considering the applicable margin of 1.25 percent in effect as of June 30, 2006, the total interest rate on the $60 million portion of Revolver borrowings covered by the Revolver Swaps was 5.47 percent at June 30, 2006.

Future Capital Needs and Commitments

Part of our strategy is to make acquisitions which increase cash available for distribution to our unitholders. Long-term cash requirements for asset acquisitions are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities and the issuance of additional equity and debt securities. Our ability to make these acquisitions in the future will depend in part on the availability of debt financing and on our ability to periodically use equity financing through the issuance of new common units, which will depend on various factors, including prevailing market conditions, interest rates and our financial condition and credit rating at the time. In July 2006, we borrowed an additional $15 million under the Revolver to replenish cash used to fund the Transwestern Acquisition in June 2006.

In 2006, we anticipate making capital expenditures, excluding acquisitions, of $16 to $18 million for coal services related projects and other property and equipment and $19 to $21 million for natural gas midstream system expansion projects. Management intends to fund these capital expenditures with a combination of cash flows provided by operating activities and borrowings under the Revolver, under which we had $115.5 million borrowing capacity as of June 30, 2006, and potentially with proceeds from the issuance of additional equity, as referred to in Note 1 in the Notes to Consolidated Financial Statements. We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Short-term cash requirements, such as operating expenses and quarterly distributions to our general partner and unitholders, are expected to be funded through operating cash flows.

Results of Operations

Selected Financial Data – Consolidated

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in millions, except per unit data)			
Revenues	$123.5	$109.6	$258.6	$ 155.8
Expenses	94.2	89.2	211.1	121.1
Operating income	$ 29.3	$ 20.4	$ 47.5	$ 34.7
Net income	$ 13.2	$ 16.9	$ 21.6	$ 14.4
Net income per limited partner unit, basic and diluted	$ 0.30	$ 0.39	$ 0.48	$ 0.36
Cash flows provided by operating activities	$ 37.2	$ 28.3	$ 50.5	$ 39.8

The increase in net income for the six months ended June 30, 2006, compared to the same period in 2005 was primarily attributable to a $13.2 million increase in operating income which was partially offset by a $3.3 million increase in derivative losses and a $2.3 million increase in interest expense for borrowings used to fund acquisitions. The decrease in net income for the three months ended June 30, 2006, compared to the same period in 2005 was primarily attributable to a $11.1 million increase in derivative losses and a $1.4 million increase in interest expense for borrowings used to fund acquisitions, partially offset by a $9.2 million increase in operating income. Operating income increased in the three months and six months ended June 30, 2006, primarily due to the contribution of the natural gas midstream segment that was acquired in March 2005 and increased coal royalty revenue resulting from higher coal prices and increased coal production.

Coal Segment

The coal segment includes coal reserves, coal services and other land assets. We enter into leases with various third-party operators for the right to mine coal reserves on our properties in exchange for royalty payments. We do not operate any mines. In addition to coal royalty revenues, we generate coal services revenues from fees charged to lessees for the use of coal preparation and loading facilities and from equity earnings from the Massey joint venture. We also generate revenues from the sale of standing timber on our properties, the collection of wheelage fees and oil and natural gas well royalties.

Coal royalties are impacted by several factors that we generally cannot control. The number of tons mined annually is determined by an operator's mining efficiency, labor availability, geologic conditions, access to capital, ability to market coal and ability to arrange reliable transportation to the end-user. The possibility exists that new legislation or regulations have or may be adopted which may have a significant impact on the mining operations of our lessees or their customers' ability to use coal and which may require us, our lessees or our lessee's customers to change operations significantly or incur substantial costs. See Item 1A, "Risk Factors."

Operations and Financial Summary – Coal Segment

Three Months Ended June 30, 2006, Compared with Three Months Ended June 30, 2005

	Three Months Ended June 30,		%
	2006	2005	Change
Financial Highlights	(in millions, except as noted)		
Revenues			
Coal royalties	$ 24.3	$ 20.1	21%
Coal services	1.4	1.3	8%
Other	2.2	2.2	0%
Total revenues	27.9	23.6	18%
Expenses			
Operating	1.3	1.1	18%
Taxes other than income	0.1	0.2	(50%)
General and administrative	2.5	1.7	47%
Depreciation, depletion and amortization	4.7	4.3	9%
Total expenses	8.6	7.3	18%
Operating income	$ 19.3	$ 16.3	18%
Operating Statistics			
Royalty coal tons produced by lessees (tons in millions)	8.0	7.3	10%
Average royalty per ton ($/ton)	$ 3.04	$ 2.78	10%

Revenues. Coal royalty revenues increased due to a higher average royalty per ton and increased production. The average royalty per ton increased to $3.04 in the second quarter of 2006 from $2.78 in the second quarter of 2005. The increase in the average royalty per ton was primarily due to a greater percentage of coal being produced from certain price-sensitive leases and stronger market conditions for coal resulting in higher prices. Coal production by our lessees increased primarily due to production on our Illinois Basin property, which we acquired in the third quarter of 2005, and on our central Appalachian property due to the Huff Creek Acquisition in May 2006.

Other revenues did not significantly change in the aggregate for the second quarter of 2006 compared to the second quarter of 2005. However, the components of other revenues did change. In the second quarter of 2006, we received approximately $0.5 million in revenues for the management of certain coal properties, approximately $0.5 million of forfeiture income from lessees with rolling recoupment periods, approximately $0.4 million in railcar rental income related to railcars purchased in June 2005 and approximately $0.2 million of additional wheelage fees, primarily as a result of an April 2005 acquisition. In the second quarter of 2005, we received $1.5 million from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents.

Expenses. General and administrative expenses increased due to absorbing operations related to our 2005 and 2006 acquisitions, increased professional fees and payroll costs relating to evaluating acquisition opportunities and increased reimbursement to our general partner for shared corporate overhead costs. Depreciation, depletion and amortization expense increased due to the increase in production and a higher depletion rate on recently acquired reserves.

Six Months Ended June 30, 2006, Compared with Six Months Ended June 30, 2005

	Six Months Ended June 30, 2006	2005	% Change
Financial Highlights	(in millions, except as noted)		
Revenues			
Coal royalties	$ 46.7	$ 38.2	22%
Coal services	2.8	2.6	8%
Other	3.7	2.7	37%
Total revenues	53.2	43.5	22%
Expenses			
Operating	2.2	2.2	0%
Taxes other than income	0.4	0.5	(20%)
General and administrative	4.7	4.0	18%
Depreciation, depletion and amortization	9.5	8.2	16%
Total expenses	16.8	14.9	13%
Operating income	$ 36.4	$ 28.6	27%
Operating Statistics			
Royalty coal tons produced by lessees (tons in millions)	15.7	14.0	12%
Average royalty per ton ($/ton)	$ 2.98	$ 2.73	9%

Revenues. Coal royalty revenues increased due to a higher average royalty per ton and increased production. The average royalty per ton increased to $2.98 for the six months ended June 30, 2006, from $2.73 for the six months ended June 30, 2005. The increase in the average royalty per ton was primarily due to a greater percentage of coal being produced from certain price-sensitive leases and stronger market conditions for coal resulting in higher prices. Coal production by our lessees increased primarily due to production on our Illinois Basin property, which we acquired in the third quarter of 2005.

Other revenues increased primarily due to the following factors. In the six months ended June 30, 2006, we received approximately $0.9 million in revenues for the management of certain coal properties, approximately $0.5 million of forfeiture income from lessees with rolling recoupment periods, approximately $0.4 million in railcar rental income related to railcars purchased in June 2005 and approximately $0.4 million of additional wheelage fees, primarily as a result of an April 2005 acquisition. In the six months ended June 30, 2005, we received $1.5 million from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents.

Expenses. Operating expenses did not increase despite the increase in production because production on our subleased properties decreased by 19 percent to 1.8 million tons for the six months ended June 30, 2006, due to the movement of longwall mining operations at one of these properties. This decrease in production on subleased properties resulted in decreased royalty expense. General and administrative expenses increased due to absorbing operations related to our 2005 and 2006 acquisitions, increased professional fees and payroll costs relating to evaluating acquisition opportunities and increased reimbursement to our general partner for shared corporate overhead costs. Depreciation, depletion and amortization expense increased due to the increase in production and a higher depletion rate on reserves acquired in 2005.

Natural Gas Midstream Segment

We purchased our natural gas midstream business on March 3, 2005. The results of operations of the natural gas midstream segment since that date are included in the operations and financial summary table below.

The natural gas midstream segment derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. Revenues, profitability and the future rate of growth of the natural gas midstream segment are highly dependent on market demand and prevailing NGL and natural gas prices. Historically, changes in the prices of most NGL products have correlated with changes in the price of crude oil. NGL and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for NGL products and natural gas market uncertainty.

Operations and Financial Summary – Natural Gas Midstream Segment

Three Months Ended June 30, 2006, Compared with Three Months Ended June 30, 2005

	Three Months Ended June 30,		
	2006	**2005**	**% Change**
Financial Highlights	**(in millions, except as noted)**		
Revenues			
Residue gas	$ 58.2	$ 44.8	30%
Natural gas liquids	34.2	36.7	(7%)
Condensate	2.6	3.4	(24%)
Gathering and transportation fees	0.4	0.2	100%
Total natural gas midstream revenues	95.4	85.1	12%
Marketing revenue, net	0.2	0.8	(75%)
Total revenues	$ 95.6	$ 85.9	11%
Operating costs and expenses			
Cost of gas purchased	75.7	72.6	4%
Operating	2.8	3.2	(13%)
Taxes other than income	0.3	0.5	(40%)
General and administrative	2.7	1.8	50%
Depreciation and amortization	4.1	3.7	11%
Total operating expenses	$ 85.6	$ 81.8	5%
Operating income	$ 10.0	$ 4.1	144%
Operating Statistics			
Inlet volumes (Bcf)	12.7	11.5	10%
Midstream processing margin (1)	$ 19.7	$ 12.5	58%

(1) Midstream processing margin consists of total natural gas midstream revenues minus the cost of gas purchased.

Revenues. Revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from inlet volumes received, condensate collected and sold, gathering and other fees primarily from natural gas volumes connected to our gas processing plants and the purchase and resale of natural gas not connected to our gathering systems and processing plants. The increase in natural gas midstream revenues was primarily a result of overall market changes in NGL and natural gas prices. Average NGL prices increased from the second quarter of 2005 to the second quarter of 2006, which was offset by a decrease in average natural gas prices over the same period.

Expenses. Operating costs and expenses primarily consisted of the cost of gas purchased and also included operating expenses, taxes other than income, general and administrative expenses and depreciation and amortization.

Cost of gas purchased consisted of amounts payable to third-party producers for gas purchased under percentage of proceeds and keep-whole contracts. The decrease in the average purchase price for natural gas was a direct result of overall market decreases in natural gas prices. The following table shows a summary of the effects of derivative activities on midstream processing margin:

	Three Months Ended June 30,	
	2006	**2005**
	(in thousands)	
Midstream processing margin, as reported	$ 19,658	$ 12,504
Derivatives losses (gains) included in midstream processing margin	711	(589)
Midstream processing margin before impact of derivatives	20,369	11,915
Cash settlements on derivatives	(5,139)	(1,251)
Midstream processing margin, adjusted for derivatives	$ 15,230	$ 10,664

General and administrative expenses increased primarily due to additional personnel added to support the business and increased reimbursement to our general partner for shared corporate overhead costs.

Six Months Ended June 30, 2006, Compared with Six Months Ended June 30, 2005

Financial Highlights	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005 (1)	% Change
	(in millions, except as noted)		
Revenues			
Residue gas	$ 136.7	$ 61.8	121%
Natural gas liquids	62.2	45.0	38%
Condensate	4.8	3.4	41%
Gathering and transportation fees	0.8	1.2	(33%)
Total natural gas midstream revenues	204.5	111.4	84%
Marketing revenue, net	0.9	0.9	0%
Total revenues	$ 205.4	$ 112.3	83%
Operating costs and expenses			
Cost of gas purchased	174.3	94.5	84%
Operating	5.4	4.0	35%
Taxes other than income	0.7	0.6	17%
General and administrative	5.7	2.2	159%
Depreciation and amortization	8.1	4.9	65%
Total operating expenses	$ 194.2	$ 106.2	83%
Operating income	$ 11.2	$ 6.1	84%
Operating Statistics			
Inlet volumes (Bcf)	24.8	15.4	61%
Midstream processing margin (2)	$ 30.2	$ 16.9	79%

(1) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the acquisition of Cantera Gas Resources, LLC (the "Cantera Acquisition").
(2) Midstream processing margin consists of total natural gas midstream revenues minus the cost of gas purchased.

Revenues. Revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from inlet volumes received, condensate collected and sold, gathering and other fees primarily from natural gas volumes connected to our gas processing plants and the purchase and resale of natural gas not connected to our gathering systems and processing plants. The increase in natural gas midstream revenues was primarily a result of market changes in NGL and natural gas prices. Average pricing for both NGLs and natural gas increased for the comparative periods.

Expenses. Operating costs and expenses primarily consisted of the cost of gas purchased and also included operating expenses, taxes other than income, general and administrative expenses and depreciation and amortization.

Cost of gas purchased consisted of amounts payable to third-party producers for gas purchased under percentage of proceeds and keep-whole contracts. The increase in the average purchase price for natural gas was primarily due to overall market increases in natural gas prices. Included in cost of gas purchased for the six months ended June 30, 2006, was a $4.6 million non-cash charge to reserve for amounts related to balances assumed as part of the Cantera Acquisition. The following table shows a summary of the effects of derivative activities on midstream processing margin:

	Six Months Ended June 30,	
	2006	2005
	(in thousands)	
Midstream processing margin, as reported	$30,188	$16,945
Derivatives losses (gains) included in midstream processing margin	450	(589)
Midstream processing margin before impact of derivatives	30,638	16,356
Cash settlements on derivatives	(8,061)	(1,251)
Midstream processing margin, adjusted for derivatives	$22,577	$15,105

General and administrative expenses increased primarily due to additional personnel added to support the business and increased reimbursement to our general partner for shared corporate overhead costs.

Other

Interest Expense. Interest expense, net, increased by $1.4 million from $2.7 million in the second quarter of 2005 to $4.1 million in the second quarter of 2006. Interest expense, net, increased by $2.3 million from $5.6 million in the six months ended June 30, 2005, to $7.9 million in the six months ended June 30, 2006. The increase in both periods was primarily due to interest incurred on additional borrowings under the Revolver to finance the Cantera Acquisition and coal property acquisitions in 2005 and 2006.

Derivatives. Because our natural gas derivatives and a large portion of our NGL derivatives no longer qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in oil and gas prices.

Hedge ineffectiveness is associated with hedging contracts that we accounted for using hedge accounting under SFAS No. 133. The unrealized loss due to changes in fair market value for the three months and six months ended June 30, 2006, is associated with our derivative contracts that we no longer account for using hedge accounting and represents changes in the fair value of our open contracts during the period. The $13.9 million unrealized loss due to changes in fair market value for the six months ended June 30, 2005, represents the change in market value of derivative agreements between the time we entered into the agreements in January 2005 and the time they qualified for hedge accounting after closing the Cantera Acquisition in March 2005.

Environmental

The operations of our coal lessees and our natural gas midstream segment are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of our coal property leases impose liability for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. The lessees are bonded and have indemnified us against any and all future environmental liabilities. We regularly visit coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of our coal lessees and our natural gas midstream segment comply with existing regulations and does not expect any material impact on our financial condition or results of operations.

As of June 30, 2006 and 2005, our environmental liabilities were $2.4 million and $1.7 million, which represents our best estimate of the liabilities as of those dates related to our coal and natural gas midstream businesses. We have reclamation bonding requirements with respect to certain unleased and inactive properties.

Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

Recent Accounting Pronouncements

No accounting pronouncements issued in the second quarter of 2006 are expected to have a material effect on our consolidated financial position, results of operations or cash flows.

Forward-Looking Statements

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

- our ability to generate sufficient cash from our midstream and coal businesses to pay the minimum quarterly distribution to our general partner and our unitholders;
- energy prices generally and specifically, the price of natural gas and the price of NGLs;
- the relationship between natural gas and NGL prices;
- the price of coal and its comparison to the price of natural gas and oil;
- the volatility of commodity prices for coal, natural gas and NGLs;
- the projected demand for coal, natural gas and NGLs;
- the projected supply of coal, natural gas and NGLs;
- our ability to successfully manage our relatively new natural gas midstream business;
- our ability to acquire new coal reserves or midstream assets on satisfactory terms;
- the price for which coal reserves can be acquired;
- our ability to continually find and contract for new sources of natural gas supply;
- our ability to retain existing or acquire new midstream customers;
- our ability to lease new and existing coal reserves;
- the ability of our lessees to produce sufficient quantities of coal on an economic basis from our reserves;
- the ability of our lessees to obtain favorable contracts for coal produced from our reserves;
- competition among producers in the coal industry generally and among natural gas midstream companies;
- our exposure to the credit risk of our coal lessees and midstream customers;
- the extent to which the amount and quality of our actual production differ from our estimated recoverable proved coal reserves;
- hazards or operating risks incidental to midstream operations;
- unanticipated geological problems;
- the dependence of our midstream business on having connections to third party pipelines;
- the availability of required materials and equipment;
- the occurrence of unusual weather or operating conditions including force majeure events;
- the failure of our infrastructure and our lessees’ mining equipment or processes to operate in accordance with specifications or expectations;
- delays in anticipated start-up dates of our lessees’ mining operations and related coal infrastructure projects;
- environmental risks affecting the mining of coal reserves and the production, gathering and processing of natural gas;
- the timing of receipt of necessary governmental permits by our 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 current and future litigation regarding mine permitting;

- risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions (including the impact of potential terrorist attacks);
- the experience and financial condition of our lessees, including their ability to satisfy their royalty, environmental, reclamation and other obligations to us and others;
- our ability to expand our midstream business by constructing new gathering systems, pipelines and processing facilities on an economic basis and in a timely manner;
- coal handling joint venture operations;
- changes in financial market conditions;
- the completion of GP Holdings' initial public offering; and
- other risks set forth in Item 1A, "Risk Factors," of our Annual Report on Form 10-K for the year ended December 31, 2005.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission, including our Annual Report on Form 10-K for the year ended December 31, 2005. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management's views only as of the date hereof. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise.

Item 3 *Quantitative and Qualitative Disclosures About Market Risk*

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are NGL, crude oil, natural gas and coal price risks and interest rate risk.

We are also indirectly exposed to the credit risk of our customers and lessees. If our customers or lessees become financially insolvent, they may not be able to continue operating or meet their payment obligations to us.

Price Risk Management

Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to seek to mitigate the price risks associated with fluctuations in natural gas, NGL and crude oil prices as they relate to our natural gas midstream business. Prior to May 1, 2006, these financial instruments were historically 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 is significantly affected by energy price fluctuations.

Because our natural gas derivatives and a large portion of our NGL derivatives no longer qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in oil and gas prices.

See the discussion and tables in Note 4 in the Notes to Consolidated Financial Statements for a description of our derivative program and a listing of open derivative agreements and their fair value as of June 30, 2006.

Interest Rate Risk

As of June 30, 2006, our $236.9 million of outstanding indebtedness under the Revolver carried a variable interest rate throughout its term. We executed interest rate derivative transactions in September 2005 to effectively convert the interest rate on $60 million of the amount outstanding under the Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 4.22 percent plus the applicable margin. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133.

Item 4 *Controls and Procedures*

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of June 30, 2006. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported accurately and on a timely basis. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of June 30, 2006, such disclosure controls and procedures were effective.

(b) Changes in Internal Control over Financial Reporting

No changes were made in our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except that we evaluated the controls in our natural gas midstream business that we acquired in March 2005 and have integrated those controls into our existing internal control structure.

PART II. OTHER INFORMATION

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

Item 1A ***Risk Factors***

Recent new mining laws and regulations could increase operating costs and limit our lessees' ability to produce coal, which could have an adverse effect on our coal royalty revenues.

Recent mining accidents in West Virginia and Kentucky have received national attention and instigated responses at the state and national level that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. In January 2006, West Virginia passed a law imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. On March 7, 2006, New Mexico Governor Bill Richardson signed into law an expanded miner safety program including more stringent requirements for accident reporting and the installation of additional mine safety equipment at underground mines. Similarly, on April 27, 2006, Kentucky Governor Ernie Fletcher signed mine safety legislation that includes requirements for increased inspections of underground mines and additional mine safety equipment and authorizes the assessment of penalties of up to $5,000 per incident for violations of mine ventilation or roof control requirements.

On June 15, 2006, the President signed new mining safety legislation that mandates similar improvements in mine safety practices, increases civil and criminal penalties for non-compliance, requires the creation of additional mine rescue teams, and expands the scope of federal oversight, inspection and enforcement activities. Earlier, the federal Mine Safety Health Administration announced the promulgation of new emergency rules on mine safety that took effect immediately upon their publication in the *Federal Register* on March 9, 2006. These rules address mine safety equipment, training, and emergency reporting requirements. Implementing and complying with these new laws and regulations could adversely affect our lessees' coal production and could therefore have an adverse affect on our coal royalty revenues and our ability to make distributions.

Item 6 ***Exhibits***

12.1 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.

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 RESOURCE PARTNERS, L.P.

By: PENN VIRGINIA RESOURCE GP, LLC

Date: August 3, 2006	By: /s/ Frank A. Pici Frank A. Pici Vice President and Chief Financial Officer
Date: August 3, 2006	By: /s/ Forrest W. McNair Forrest W. McNair Vice President and Controller

Exhibit 12.1

Penn Virginia Resource Partners, L.P.
Statement of Computation of Ratio of Earnings to Fixed Charges Calculation
(in thousands, except ratios)

	January 1, 2001 through October 30, 2001	October 30, 2001 through December 31, 2001	Years Ended December 31, 2002	2003	2004	2005	Six Months Ended June 30, 2006
Earnings							
Pre-tax income *	$ 19,113	$ 3,677	$ 24,686	$ 22,690	$ 34,315	$ 51,161	$ 23,446
Fixed charges	7,027	274	1,786	5,048	7,328	14,351	8,910
Total earnings	**$ 26,140**	**$ 3,951**	**$ 26,472**	**$ 27,738**	**$ 41,643**	**$ 65,512**	**$ 32,356**
Fixed Charges							
Interest expense **	$ -	$ 269	$ 1,758	$ 4,986	$ 7,267	$ 14,053	$ 8,625
Interest expense - affiliate	7,003	-	-	-	-	-	-
Rental interest factor	24	5	28	62	61	298	285
Total fixed charges	**$ 7,027**	**$ 274**	**$ 1,786**	**$ 5,048**	**$ 7,328**	**$ 14,351**	**$ 8,910**
Ratio of earnings to fixed charges	**3.7x**	**14.4x**	**14.8x**	**5.5x**	**5.7x**	**4.6x**	**3.6x**

* Excludes equity earnings from investees and includes capitalized interest.
** Includes capitalized interest.

Exhibit 31.1

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

I, A. James Dearlove, Chief Executive Officer of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P. (the “Registrant”), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant (this “Report”);

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

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

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

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

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

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

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

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

   (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 3, 2006

/s/ A. James Dearlove
A. James Dearlove
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, Vice President and Chief Financial Officer of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P. (the “Registrant”), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant (this “Report”);

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

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

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

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

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

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

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

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

   (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 3, 2006

/s/ Frank A. Pici

Frank A. Pici
Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Quarterly Report of Penn Virginia Resource Partners, L.P. (the “Partnership”) on Form 10-Q for the quarter ended June 30, 2006, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, A. James Dearlove, Chief Executive Officer of Penn Virginia Resource GP, LLC, the general partner of the Partnership, 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 Partnership.

Date: August 3, 2006

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

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership 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 Resource Partners, L.P. (the “Partnership”) on Form 10-Q for the quarter ended June 30, 2006, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Frank A. Pici, Vice President and Chief Financial Officer of Penn Virginia Resource GP, LLC, the general partner of the Partnership, 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 Partnership.

Date: August 3, 2006

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

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