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 March 31, 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: 1-13283

PENN VIRGINIA CORPORATION
(Exact name of registrant as specified in its charter)

Virginia	23-1184320
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

THREE RADNOR CORPORATE CENTER, SUITE 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.
[ ] Yes [X] 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 [X] Accelerated filer [ ] 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 May 1, 2006, 18,648,074 shares of common stock of the registrant were issued and outstanding.

PENN VIRGINIA CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1 ***Financial Statements***

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

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Revenues		
Natural gas	$ 60,210	$ 38,260
Oil and condensate	4,791	3,413
Natural gas midstream	109,181	26,278
Coal royalties	22,422	18,053
Other	4,303	2,206
Total revenues	200,907	88,210
Expenses		
Cost of midstream gas purchased	98,651	21,837
Operating	8,478	5,099
Exploration	7,891	7,659
Taxes other than income	4,965	3,347
General and administrative	10,675	6,720
Depreciation, depletion and amortization	21,581	15,844
Total expenses	152,241	60,506
Operating income	48,666	27,704
Other income (expense)		
Interest expense	(4,788)	(3,378)
Interest income and other	396	319
Derivative losses	(158)	(14,317)
Income before minority interest and income taxes	44,116	10,328
Minority interest	4,889	(1,656)
Income tax expense	15,119	4,944
Net income	$ 24,108	$ 7,040
Net income per share, basic	$ 1.29	$ 0.38
Net income per share, diluted	$ 1.28	$ 0.38
Weighted average shares outstanding, basic	18,652	18,490
Weighted average shares outstanding, diluted	18,873	18,694

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

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

	March 31, 2006	December 31, 2005
	(Unaudited)	
Assets		
Current assets		
Cash and cash equivalents	$ 13,992	$ 25,913
Accounts receivable	112,166	133,086
Derivative assets	9,805	11,551
Other	7,307	7,635
Total current assets	143,270	178,185
Property and equipment		
Oil and gas properties (successful efforts method)	755,981	717,423
Other property and equipment	545,837	538,035
Accumulated depreciation, depletion and amortization	(292,467)	(272,239)
Net property and equipment	1,009,351	983,219
Equity investments	27,002	26,672
Goodwill	7,718	7,718
Intangibles, net	36,785	38,051
Derivative assets	6,735	8,917
Other assets	9,456	8,784
Total assets	$ 1,240,317	$ 1,251,546
Liabilities And Shareholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 9,814	$ 8,108
Accounts payable and accrued liabilities	92,820	114,678
Derivative liabilities	17,061	29,387
Income taxes payable	6,186	2,355
Total current liabilities	125,881	154,528
Other liabilities	24,305	24,448
Derivative liabilities	12,062	11,706
Deferred income taxes	122,129	111,186
Long-term debt of the Company	67,000	79,000
Long-term debt of PVR	241,888	246,846
Minority interest in PVR	309,753	313,524
Shareholders' equity		
Preferred stock of $100 par value – 100,000 shares authorized; none issued	-	-
Common stock of $0.01 par value – 32,000,000 shares authorized; 18,624,210 and 18,624,002 shares issued and outstanding at March 31, 2006, and December 31, 2005	187	186
Paid-in capital	101,971	98,541
Retained earnings	244,459	222,456
Deferred compensation obligation	758	580
Accumulated other comprehensive income	(3,987)	(7,816)
Treasury stock – 27,100 and 23,644 shares common stock, at cost, on March 31, 2006, and December 31, 2005	(1,046)	(832)
Unearned compensation	(5,043)	(2,807)
Total shareholders' equity	337,299	310,308
Total liabilities and shareholders' equity	$ 1,240,317	$ 1,251,546

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

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

	Three Months Ended March 31,	
	2006	**2005**
Cash flows from operating activities		
Net income	$ 24,108	$ 7,040
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	21,581	15,844
Derivative losses	158	14,317
Deferred income taxes	8,882	3,543
Minority interest	4,889	(1,656)
Dry hole and unproved leasehold expense	4,375	2,439
Other	848	1,600
Changes in operating assets and liabilities	854	(12,276)
Net cash provided by operating activities	65,695	30,851
Cash flows from investing activities		
Proceeds from the sale of property and equipment	1,228	9,766
Acquisitions, net of cash acquired	(6,245)	(204,984)
Additions to property and equipment	(46,781)	(37,586)
Net cash used in investing activities	(51,798)	(232,804)
Cash flows from financing activities		
Dividends paid	(2,094)	(2,081)
Distributions paid to minority interest holders of PVR	(9,144)	(5,788)
Proceeds from issuance of PVR partners' capital	-	125,185
Proceeds from borrowings of the Company	15,000	17,000
Repayments of borrowings of the Company	(27,000)	(15,000)
Proceeds from borrowings of PVR	-	211,800
Repayments of borrowings of PVR	(3,300)	(131,500)
Payments for debt issuance costs	-	(2,039)
Other	720	497
Net cash provided by (used in) financing activities	(25,818)	198,074
Net decrease in cash and cash equivalents	(11,921)	(3,879)
Cash and cash equivalents – beginning of period	25,913	25,471
Cash and cash equivalents – end of period	$ 13,992	$ 21,592
Supplemental disclosures:		
Cash paid during the periods for:		
Interest (net of amounts capitalized)	$ 6,152	$ 3,331
Income taxes	$ 2,400	$ -

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

PENN VIRGINIA CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Unaudited
March 31, 2006

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is an independent energy company that is engaged in three primary business segments. Our oil and gas segment explores for, develops, produces and sells crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. Our coal segment and natural gas midstream segment operate through our 39 percent ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"). Due to our control of the general partner of PVR, the financial results of the Partnership are included in our consolidated financial statements. However, PVR functions with a capital structure that is independent of the Company, consisting of its own debt instruments and publicly traded common units.

In the coal segment, PVR does not operate any mines. Instead, PVR enters into leases with various third-party operators which give those operators the right to mine coal reserves on PVR's land in exchange for royalty payments. PVR also provides fee-based infrastructure facilities to some of its 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. PVR also sells timber growing on its land.

PVR purchased its midstream business on March 3, 2005, through the acquisition of Cantera Gas Resources, LLC (the "Cantera Acquisition"). As a result of the Cantera Acquisition, PVR owns and operates a significant set of midstream assets. PVR's 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.

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 consolidated financial statements include the accounts of Penn Virginia, all wholly-owned subsidiaries of the Company and the Partnership, of which we indirectly owned the sole two percent general partner interest and an approximately 37 percent limited partner interest as of March 31, 2006. Penn Virginia Resource GP, LLC, a wholly-owned subsidiary of Penn Virginia, serves as the Partnership's general partner and controls the Partnership. We own and operate our undivided oil and gas reserves through our wholly-owned subsidiaries. We account for our undivided interest in oil and gas properties using the proportionate consolidation method, whereby our share of assets, liabilities, revenues and expenses is included in the appropriate classification in the financial statements. Intercompany balances and transactions have been eliminated in consolidation. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and Securities and Exchange Commission ("SEC") regulations. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation 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 three months ended March 31, 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.

New Accounting Standards

In December 2004, the Financial Accounting Standards Board (the "FASB") issued the final revised version of SFAS No. 123(R), *Share-Based Payment,* which requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. In March 2005, the SEC issued Staff Accounting Bulletin ("SAB") No. 107, *Share-Based Payment,* regarding the interaction between SFAS No. 123(R) and certain SEC rules and regulations. Effective January 1, 2006, we adopted SFAS No. 123(R). Beginning January 1, 2006, we recognize compensation expense related to share-based payments on a straight-line basis over the requisite service period for share-based payment awards granted after the effective date of SFAS No. 123(R). For unvested stock options granted prior to the effective date of SFAS No. 123(R), we recognize compensation expense in the same manner as was used for pro forma disclosures prior to the effective date of SFAS No. 123(R). See Note 6 for more information regarding the adoption of SFAS No. 123(R).

In June 2005, the Emerging Issues Task Force ("EITF") reached a consensus on EITF Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.* This consensus applies to voting right entities not within the scope of FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities,* in which the investor is the general partner in a limited partnership or functional equivalent. The EITF consensus is that the general partner in a limited partnership is presumed to control that limited partnership regardless of the extent of the general partner's ownership interest and, therefore, should include the limited partnership in its consolidated financial statements. The general partner may overcome this presumption of control and not consolidate the entity if the limited partners have either: (a) the substantive ability to dissolve (liquidate) the limited partnership or otherwise remove the general partner through substantive kick-out rights that can be exercised without having to show cause; or (b) substantive participating rights in managing the partnership. This guidance became immediately effective upon ratification by the FASB on June 29, 2005, for all newly formed limited partnerships and for existing limited partnerships for which the partnership agreements have been modified. We consolidate PVR, and the adoption of EITF Issue No. 04-5 on January 1, 2006, did not change our consolidated accounting with respect to PVR.

3. Derivatives Instruments and Hedging Activities

Oil and Gas Segment Commodity Derivatives

The fair values of our oil and gas derivative contracts are determined based on third party forward price quotes for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of March 31, 2006. The following table sets forth our positions as of March 31, 2006:

	Average Volume Per Day	Weighted Average Price		Estimated Fair Value (in thousands)
		Floor	Ceiling	
Natural Gas Costless Collars	**(in Mmbtus)**	**(per Mmbtu)**		
Second Quarter 2006	28,330	$ 6.94	$ 11.81	1,788
Third Quarter 2006	22,000	$ 7.82	$ 12.25	1,749
Fourth Quarter 2006	20,011	$ 8.23	$ 15.32	1,148
First Quarter 2007	15,000	$ 9.00	$ 19.20	961
Second Quarter 2007	10,000	$ 7.00	$ 12.65	53
Third Quarter 2007	10,000	$ 7.00	$ 12.65	10
Fourth Quarter 2007 (October only)	10,000	$ 7.00	$ 12.65	(17)
Crude Oil Costless Collars	**(in barrels)**	**(per barrel)**		
Second Quarter 2006	200	$ 60.00	$ 72.20	(20)
Third Quarter 2006	200	$ 60.00	$ 72.20	(43)
Fourth Quarter 2006	200	$ 60.00	$ 72.20	(53)
First Quarter 2007	200	$ 60.00	$ 72.20	(56)
Second Quarter 2007	200	$ 60.00	$ 72.20	(59)
Third Quarter 2007	200	$ 60.00	$ 72.20	(58)
Fourth Quarter 2007	200	$ 60.00	$ 72.20	(56)
Total				$ 5,347

Based upon our assessment of our derivative agreements at March 31, 2006, we reported (i) a net derivative asset of approximately $5.3 million, (ii) a gain in accumulated other comprehensive income of $0.8 million, net of related income tax expense of $0.4 million and (iii) a derivative gain of $5.9 million related to derivatives in the oil and gas segment. The derivative gain represents a $5.3 million mark-to-market adjustment on certain derivatives that no longer qualify for hedge accounting and a $0.6 million gain on ineffectiveness. In connection with monthly settlements, we recognized net hedging losses in natural gas and oil revenues of $1.3 million for the three months ended March 31, 2006. Based upon future oil and natural gas prices as of March 31, 2006, we expect to realize $5.5 million of hedging gains within the next 12 months. The amounts that we ultimately realize will vary due to changes in the fair value of the open derivative agreements prior to settlement. We recognized net hedging losses of $0.3 million for the three months ended March 31, 2005.

At the time we entered into our natural gas derivatives, physical sales prices correlated well with NYMEX natural gas prices; however, beginning in the second half of 2005, basis differentials for certain derivative agreements widened as NYMEX natural gas prices reached historically high levels. In the first quarter of 2006, our correlation assessment indicated that certain NYMEX natural gas 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 certain natural gas derivatives and recognized a net mark-to-market gain of $5.3 million in the first quarter of 2006.

Natural Gas Midstream Segment Commodity Derivatives

The fair values of PVR's derivative agreements are determined based on forward price quotes and regression analysis for the respective commodities as of March 31, 2006. The following table sets forth PVR's positions as of March 31, 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)**	
Second Quarter 2006 through Fourth Quarter 2006	68,880	$ 0.4770	$ (2,359)
First Quarter 2007 through Fourth Quarter 2007	34,440	$ 0.5050	(1,343)
First Quarter 2008 through Fourth Quarter 2008	34,440	$ 0.4700	(1,396)
Propane Swaps	**(in gallons)**	**(per gallon)**	
Second Quarter 2006 through Fourth Quarter 2006	52,080	$ 0.7060	(4,139)
First Quarter 2007 through Fourth Quarter 2007	26,040	$ 0.7550	(1,992)
First Quarter 2008 through Fourth Quarter 2008	26,040	$ 0.7175	(2,075)
Crude Oil Swaps	**(in barrels)**	**(per barrel)**	
Second Quarter 2006 through Fourth Quarter 2006	1,100	$ 44.45	(7,895)
First Quarter 2007 through Fourth Quarter 2007	560	$ 50.80	(3,599)
First Quarter 2008 through Fourth Quarter 2008	560	$ 49.27	(3,293)
Natural Gas Swaps	**(in MMbtu)**	**(per MMbtu)**	
Second Quarter 2006 through Fourth Quarter 2006	7,500	$ 7.05	1,994
First Quarter 2007 through Fourth Quarter 2007	4,000	$ 6.97	3,608
First Quarter 2008 through Fourth Quarter 2008	4,000	$ 6.97	2,821
			$ (19,668)

Based upon the assessment of derivative agreements at March 31, 2006, PVR reported (i) a net derivative liability related to the natural gas midstream segment of $19.7 million, (ii) a loss in accumulated other comprehensive income of $5.7 million, net of a related income tax benefit of $3.1 million, and (iii) a net unrealized loss on derivatives for hedge ineffectiveness of $0.1 million for the three months ended March 31, 2006, related to cash flow hedges in the natural gas midstream segment. In connection with monthly settlements, PVR recognized net hedging losses in natural gas midstream revenues of $2.2 million for the three months ended March 31, 2006, and net hedging gains in cost of midstream gas purchased of $2.4 million for the three months ended March 31, 2006. Based upon future commodity prices as of March 31, 2006, PVR expects to realize $12.9 million of hedging losses within the next 12 months. The amounts that PVR will ultimately realize will vary due to changes in the fair value of the open derivative agreements prior to settlement. Because all hedged volumes relate to periods beginning after March 31, 2005, PVR had no monthly settlements and recognized no net hedging losses in natural gas midstream revenues for the three months ended March 31, 2005.

At the time PVR entered into its 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, beginning 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, PVR's correlation assessment indicated that its NYMEX natural gas derivatives and certain NGL derivatives could no longer be considered "highly effective" hedges under the parameters of the accounting rules. Consequently, PVR discontinued hedge accounting effective January 1, 2006, for its natural gas derivatives and certain NGL derivatives that were no longer considered highly effective and recognized a net mark-to-market loss of $6.0 million in the first quarter of 2006.

In November 2005, PVR 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. In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* changes in market value of the derivative instrument are charged to earnings. PVR reported (i) a derivative liability of approximately $0.3 million at March 31, 2006, and (ii) a derivative loss of $0.1 million for the three months ended March 31, 2006, related to the basis swap.

Discontinuation of Hedge Accounting

Because a large portion of our natural gas derivatives and 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 commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we will recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, included in accumulated other comprehensive income will be reported in future earnings through 2008 as the original hedged transactions occur. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by mark-to-market gains and losses which fluctuate with volatile oil and gas prices.

Interest Rate Swaps

In September 2005, PVR entered into interest rate swap agreements to establish fixed rates on $60 million of the LIBOR-based portion of the outstanding balance on PVR's revolving credit facility until March 2010 (the "Revolver Swaps"). PVR pays 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. PVR reported (i) a derivative asset of approximately $2.0 million at March 31, 2006, and (ii) a gain in accumulated other comprehensive income of $1.3 million, net of related income tax expense of $0.7 million for the three months ended March 31, 2006, related to the Revolver Swaps. In connection with periodic settlements, PVR recognized $0.1 million in net hedging gains in interest expense for the three months ended March 31, 2006. Based upon future interest rate curves at March 31, 2006, PVR expects to realize $0.5 million of hedging gains within the next 12 months. The amounts that PVR ultimately realizes will vary due to changes in the fair value of open derivative agreements prior to settlement.

4. Pension Plans and Other Postretirement Benefits

In accordance with SFAS No. 132, *Employers' Disclosures about Pensions and Other Postretirement Benefits*, the following table provides the components of net periodic benefit costs for the respective plans shown for the three months ended March 31, 2006 and 2005 (in thousands):

	Pension		Post-retirement Healthcare	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2006	2005	2006	2005
Service cost	$ -	$ -	$ 8	$ 7
Interest cost	32	32	63	65
Amortization of prior service cost	1	1	22	22
Amortization of transitional obligation	1	1	-	-
Recognized actuarial loss	9	8	22	13
Net periodic benefit cost	$ 43	$ 42	$ 115	$ 107

5. Earnings per Share

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share for the three months ended March 31, 2006 and 2005 (in thousands, except per share data):

	Three Months Ended March 31,	
	2006	2005
Net income	$ 24,108	$ 7,040
Weighted average shares, basic	18,652	18,490
Effect of dilutive securities:		
Stock options	221	204
Weighted average shares, diluted	18,873	18,694
Net income per share, basic	$ 1.29	$ 0.38
Net income per share, diluted	$ 1.28	$ 0.38

6. Share-Based Payments

Adoption of New Accounting Standard

We have several stock compensation plans (collectively, the "Stock Compensation Plans") that allow incentive and nonqualified stock options and restricted stock to be granted to key employees and officers and nonqualified stock options and deferred common stock units to be granted to directors. Prior to January 1, 2006, we accounted for those plans under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related Interpretations, as permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*. Stock-based compensation cost in our statements of income prior to 2006 included only costs related to restricted stock and deferred common stock units. Prior to 2006, we did not recognize expense for options as permitted by SFAS No. 123 because all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R) using the modified prospective transition method. Under that transition method, compensation cost recognized in the three months ended March 31, 2006, includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of, January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted on or after January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated. For the three months ended March 31, 2006, we recognized $0.6 million of compensation expense related to the Stock Compensation Plans. The total income tax benefit recognized in the statements of income for the Stock Compensation Plans was $0.2 million for the three months ended March 31, 2006.

As a result of adopting SFAS No. 123(R) on January 1, 2006, our income before minority interest and income taxes and our net income for the three months ended March 31, 2006, are $0.3 million and $0.2 million lower than if we had continued to account for share-based compensation under Opinion No. 25. Basic and diluted earnings per share for the three months ended March 31, 2006, would have been $1.30 and $1.29 if we had not adopted SFAS No. 123(R), compared to reported basic and diluted earnings per share of $1.29 and $1.28.

Prior to the adoption of SFAS No. 123(R), we presented all tax benefits of deductions resulting from the exercise of stock options as operating cash flows in the statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $0.2 million excess tax benefit classified as a financing cash inflow would have been classified as an operating cash inflow if we had not adopted SFAS No. 123(R).

The following table illustrates the effect on net income and earnings per share as if we had not adopted SFAS No. 123(R) but had applied the fair value recognition provision of SFAS No. 123 to options granted under our stock option plans for the three months ended March 31, 2005. For purposes of this pro forma disclosure, the value of the options is estimated using a Black-Scholes-Merton option-pricing formula and amortized to expense over the options' vesting periods (in thousands, except per share data).

	Three Months Ended March 31, 2005
Net income, as reported	$ 7,040
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	198
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(345)
Pro forma net income	$ 6,893
Earnings per share	
Basic—as reported	$ 0.38
Basic—pro forma	$ 0.37
Diluted—as reported	$ 0.38
Diluted—pro forma	$ 0.37

Stock Options

The exercise price of all options granted under the Stock Compensation Plans is at the fair market value of our common stock on the date of the grant. Options may be exercised at any time after vesting and prior to 10 years following the grant. Options vest upon terms established by the Compensation and Benefits Committee of the Board of Directors. In addition, all options will vest upon a change of control of the Company, as defined by the Stock Compensation Plans. In the case of employees, if a grantee's employment terminates (i) for cause, all of the grantee's options, whether vested or unvested, will be automatically forfeited, (ii) by reason of death, disability or retirement, the grantee's options will automatically vest and (iii) for any other reason, the grantee's unvested options will be automatically forfeited. In the case of directors, if a grantee's membership on our Board of Directors terminates for any reason, the grantee's unvested options will be automatically forfeited. We have a policy of issuing new shares to satisfy share option exercises.

Options granted on or before January 2, 2004, under the Stock Compensation Plans vested on the first anniversary of the date of grant. Options granted after January 2, 2004, vest ratably over a three-year period so that one-third is exercisable after one year, another third is exercisable after two years and the remaining third is exercisable after three years.

The fair value of each option award is estimated on the date of grant using the Black-Scholes-Merton option-pricing formula that uses the assumptions noted in the following table. Expected volatilities are based on historical changes in the market value of our stock. Separate groups of employees that have similar historical exercise behavior are considered separately to estimate expected lives. Options granted have a maximum term of ten years. We base the risk-free interest rate on the U.S. Treasury rate for the week of the grant having a term equal to the expected life of the option.

	Three Months Ended March 31, 2006
Expected volatility	20.6% to 26.0%
Dividend yield	0.71%
Expected life	3.5 to 4.6 years
Risk-free interest rate	4.68% to 4.70%

The following table summarizes activity since our most recent fiscal year end with respect to the common stock options awarded under the stock option plans described above.

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
				(in thousands)
Outstanding at January 1, 2006	621,631	$ 26.68		
Granted	195,691	$ 63.07		
Exercised	(18,333)	$ 25.33		
Outstanding at March 31, 2006	798,989	$ 35.63	7.9	$ 22,111
Exercisable at March 31, 2006	454,631	$ 22.52	6.8	$ 18,541

The weighted-average grant-date fair value of options granted during the three months ended March 31, 2006, was $14.27. The total intrinsic value of options exercised during the three months ended March 31, 2006, was $0.7 million.

A summary of the status of our nonvested shares as of March 31, 2006, and changes during the three months then ended, is presented below:

Nonvested Shares	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2006	232,937	$ 9.19
Granted	195,691	14.27
Vested	(84,271)	8.71
Nonvested at March 31, 2006	344,357	$ 12.19

As of March 31, 2006, there was $3.2 million of total unrecognized compensation cost related to nonvested share-based compensation arrangements granted under the Stock Compensation Plans. That cost is expected to be recognized over a weighted-average period of 1.3 years. The total fair value of shares vested during the three months ended March 31, 2006, was $0.7 million.

Cash received from the exercise of share options for the three months ended March 31, 2006, was $0.7 million. The actual tax benefit realized for the tax deductions from option exercises totaled $0.2 million for the three months ended March 31, 2006.

Other Stock Compensation Plans

Accounting for restricted common stock and deferred common stock units did not significantly change from the disclosure in our Annual Report on Form 10-K for the year ended December 31, 2005.

7. Comprehensive Income

Comprehensive income represents certain changes in equity during the reporting period, including net income and charges directly to equity which are excluded from net income. Accumulated other comprehensive income was $4.0 million at March 31, 2006. For the three months ended March 31, 2006 and 2005, the components of comprehensive income were as follows (in thousands):

	Three Months Ended March 31,	
	2006	**2005**
Net income	$ 24,108	$ 7,040
Unrealized holding gains (losses) on hedging activities, net of tax	3,509	(6,618)
Reclassification adjustment for hedging activities, net of tax	320	196
Comprehensive income	$ 27,937	$ 618

8. Commitments and Contingencies

Drilling Commitments

In January 2006, we entered into an agreement to purchase oil and gas drilling services from a third party for three years, beginning in the third or fourth quarter of 2006. The agreement includes early termination provisions that would require us to pay a penalty if we terminate the agreement prior to the end of the original three-year term. The amount of the penalty is based on the number of days remaining in the three-year term and declines as time passes. As of March 31, 2006, drilling services had not commenced, and the pre-commencement early termination penalty amount would have been $0.7 million if we had terminated the agreement on that date. Management intends to utilize drilling services under this agreement for the full three-year term and has no plans to terminate the agreement early.

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

Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

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

As of March 31, 2006, the Partnership's environmental liabilities included $2.4 million, which represents the Partnership's best estimate of the liabilities as of that date related to the coal and natural gas midstream businesses. The Partnership has 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.

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 oil and gas operations, PVR's coal operations and PVR's natural gas midstream operations. Accordingly, our reportable segments are as follows:

- Oil and Gas – crude oil and natural gas exploration, development and production.
- Coal (the "PVR Coal" segment) – 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 (the "PVR Midstream" segment) – gas processing, gathering and other related services.

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

	Oil and Gas	PVR Coal	(1) PVR Midstream	Corporate and Other	Consolidated
As of and for the Three Months Ended March 31, 2006					
Revenues	$ 65,741	$ 25,328	$ 109,836	$ 2	$ 200,907
Operating costs and expenses	19,405	3,509	104,588	3,158	130,660
Depreciation, depletion and amortization	12,653	4,752	4,069	107	21,581
Operating income (loss)	$ 33,683	$ 17,067	$ 1,179	$ (3,263)	$ 48,666
Interest expense					(4,788)
Interest income and other					396
Derivative losses					(158)
Income before minority interest and taxes					$ 44,116
Additions to property and equipment and acquisitions, net of cash acquired	$ 44,152	$ 6,004	$ 2,561	$ 309	$ 53,026
As of and for the Three Months Ended March 31, 2005					
Revenues	$ 41,746	$ 19,812	$ 26,378	$ 274	$ 88,210
Operating costs and expenses	15,428	3,663	23,148	2,423	44,662
Depreciation, depletion and amortization	10,668	3,855	1,224	97	15,844
Operating income (loss)	$ 15,650	$ 12,294	$ 2,006	$ (2,246)	27,704
Interest expense					(3,378)
Interest income and other					319
Derivative losses					(14,317)
Income before minority interest and taxes					$ 10,328
Additions to property and equipment and acquisitions, net of cash acquired	$ 37,289	$ 38	$ 251	$ 8	$ 37,586

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

10. PVR Unit Split

On February 23, 2006, the Board of Directors of the general partner of PVR declared a two-for-one split of PVR's common and subordinated units. To effect the split, PVR 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, respectively, held of record at the close of business on March 28, 2006.

11. Subsequent Event

On May 2, 2006, our Board of Directors declared a quarterly dividend of $0.1125 per share payable June 1, 2006, to shareholders of record at the close of business on May 12, 2006.

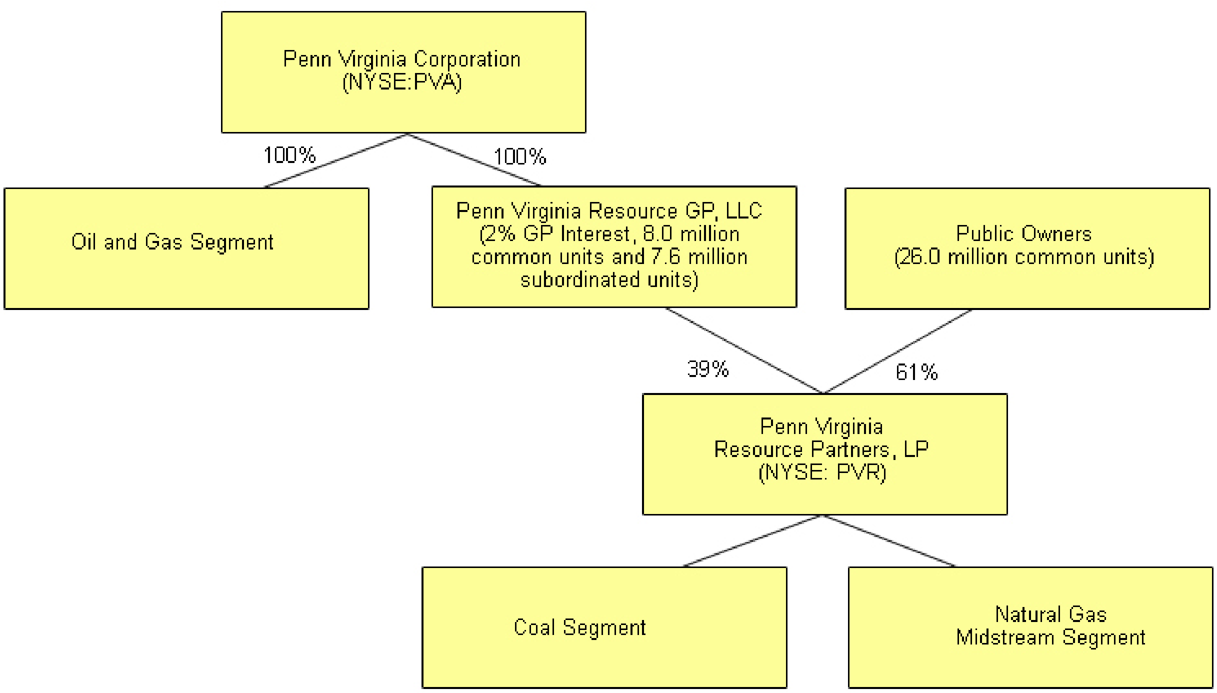
Item 2 ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following analysis of financial condition and results of operations of Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") and its subsidiaries 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
- Overview of 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 an independent energy company that is engaged in three primary business segments. Our oil and gas segment explores for, develops, produces and sells crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. Our coal and natural gas midstream segments operate through our 39 percent ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"). Penn Virginia and the Partnership are publicly traded on the New York Stock Exchange under the symbols "PVA" and "PVR." Due to our control of the general partner of the Partnership, the financial results of the Partnership are included in our consolidated financial statements. However, the Partnership functions with a capital structure that is independent of ours, consisting of its own debt instruments and publicly traded common units. The following diagram depicts our ownership of the Partnership as of March 31, 2006 (after the effect of the two-for-one unit split described in Note 10 of the Notes to Consolidated Financial Statements):



As a result of our ownership in the Partnership, we receive cash payments from PVR in the form of quarterly cash distributions. We received approximately $6.4 million of cash distributions from PVR during the three months ended March 31, 2006. As part of our ownership of the Partnership's general partner, we also own the rights, referred to as incentive distribution rights, to receive an increasing percentage of quarterly distributions of available cash from operating surplus after certain levels of cash distributions have been achieved. The cash payments we received from PVR in the first quarters of 2006 and 2005 were as follows (in millions):

	Three Months Ended March 31,	
	2006	**2005**
Limited partner units	$ 5.4	$ 4.4
General partner interest (2%)	0.3	0.2
Incentive distribution rights	0.7	-
Total	$ 6.4	$ 4.6

In November 2004, 25 percent of PVR's subordinated units converted to common units because the Partnership met certain requirements to qualify for early conversion. In November 2005, another 25 percent converted to common units. The remaining 50 percent of PVR's subordinated units are expected to convert to common units in November 2006, provided minimum quarterly distributions are paid and other conditions are met.

On February 23, 2006, the Board of Directors of the general partner of PVR declared a two-for-one split of PVR's common and subordinated units. To effect the split, PVR 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, respectively, held of record at the close of business on March 28, 2006.

Acquisitions and Investments

Our oil and gas investment strategy is to increase our presence in coal bed methane ("CBM") and unconventional natural gas to build a significant inventory of predictable, low risk development prospects and to selectively drill higher risk exploration opportunities which could make a meaningful difference to our production and reserve profile.

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

PVR expects 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 its lessees located in Knott County in eastern Kentucky. The facility is designed for the high-speed loading of unit trains at 600 tons per hour. Total capital expenditures for the construction are expected to be approximately $14 to $15 million.

Overview of Current Performance

Operating income for the three months ended March 31, 2006, was $48.7 million. The oil and gas segment, combined with the operating results of corporate, contributed $30.4 million to operating income, and PVR's coal and natural gas midstream segments, in which we have a 41 percent interest in net income, including incentive distribution rights, contributed $18.2 million, before the deduction of the 59 percent interest in net income to which we do not own rights. A description of each of our reportable segments follows:

- Oil and Gas – crude oil and natural gas exploration, development and production.
- 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.
- Corporate and Other – primarily represents corporate functions.

Oil and Gas Segment

During the first quarter of 2006, we made progress in each area as our oil and gas production increased by 14 percent to 7.3 billion cubic feet equivalent ("Bcfe"). High commodity prices also contributed significantly to our financial results. Natural gas prices have been volatile in the last few years, with the NYMEX futures market trading at record price levels for natural gas. Our realized natural gas price for the first quarter of 2006 was $8.92 per thousand cubic feet ("Mcf"), an increase of 38 percent from $6.47 per Mcf for the first quarter of 2005. As part of our risk management strategy, we use financial instruments to hedge natural gas and, to a lesser extent, oil prices. The use of this risk management strategy has resulted in lower price realizations compared to physical sale prices in the last several years.

We drilled a total of 45 gross (34.7 net) wells during the first quarter of 2006, including 39 gross (31.4 net) development wells and six gross (3.3 net) exploratory wells. One exploratory well (0.2 net) was successful, one exploratory well (0.8 net) was not successful, two gross (1.2 net) exploratory wells are currently being tested and two (1.1 net) exploratory wells are awaiting completion. We completed drilling another exploratory well in April 2006 that we determined to be unsuccessful. In the first quarter of 2006, we recognized exploration expense of $2.4 million for drilling costs related to this well. An additional $0.5 million is expected to be expensed in the second quarter of 2006. Testing continues on three other exploratory wells that were under evaluation as of December 31, 2005.

Early in 2004, we entered into a joint venture with GMX Resources, Inc. (NASDAQ: GMXR) to drill development wells in the North Carthage Field in east Texas. Through March 31, 2006, 46 gross (31.7 net) wells were drilled on this acreage, and we estimate that a total of 80 to 100 wells could ultimately be drilled.

We continue to expand our CBM production and reserve base in central Appalachia through leasehold acquisitions and the use of a proprietary horizontal drilling technology. Daily production from our horizontal CBM wells increased 17 percent from 12.5 million cubic feet equivalent ("MMcfe") for the first quarter of 2005 to approximately 14.6 MMcfe during the first quarter of 2006. The increase is a result of our growing drilling program in West Virginia. We drilled eight gross (3.8 net) horizontal CBM development wells in the first quarter of 2006, and all were successful.

Coal Segment

In the first quarter of 2006, coal royalty revenues increased 24 percent over the same period last year due to more coal being mined by PVR's lessees and increasing coal prices. Tons produced by lessees increased from 6.7 million tons in the first quarter of 2005 to 7.7 million tons in the first quarter of 2006, and average gross royalties per ton increased from $2.69 in the first quarter of 2005 to $2.90 in the first quarter of 2006. The Illinois Basin coal reserves PVR acquired in July 2005 enhanced coal royalty revenues in the first quarter of 2006 by $1.4 million. Generally, as coal prices increase, PVR's average royalties per ton also increase because most of its lessees pay royalties based on the gross sales prices of the coal mined.

In managing its properties, PVR actively works with its lessees to develop efficient methods to exploit its reserves and to maximize production from its properties. PVR earns revenues from providing fee-based coal preparation and transportation services to PVR's 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 PVR's joint venture with Massey Energy Company ("Massey"). Coal services revenues increased to $1.4 million in the first quarter of 2006 from $1.3 million in the first quarter of 2005. PVR believes that these types of fee-based infrastructure assets provide good investment and cash flow opportunities for it, and it continues to look for additional investments of this type as well as other primarily fee-based assets. PVR also earns revenues from oil and gas royalty interests, coal transportation ("wheelage") rights and the sale of standing timber on PVR's properties.

As of March 31, 2006, PVR's 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 and Raleigh 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

Increasing NGL prices helped drive the gross processing margin for PVR's natural gas midstream operations from $1.14 per Mcf in the first quarter of 2005 to $1.25 per Mcf in the first quarter of 2006, excluding a $4.6 million non-cash reserve charge in the first quarter of 2006. PVR charged $4.6 million to cost of midstream gas purchased to reserve for amounts related to balances assumed as part of the acquisition of Cantera Gas Resources, LLC (the "Cantera Acquisition") for which the possibility of collection is still being evaluated by PVR. Inlet volumes at PVR's gas processing plants and gathering systems were 134 million cubic feet ("MMcf") per day for the first quarter of 2006, an increase over 126 MMcf per day in the first quarter of 2005.

PVR continually seeks new supplies of natural gas to both offset the natural declines in production from the wells currently connected to PVR's systems and to increase throughput volume. New natural gas supplies are obtained for all of PVR's 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.

Reserves

The estimates of oil and gas reserves are the single most critical estimate included in our financial statements. Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments and the fair value of properties subject to potential impairments. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

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

There are several factors which could change our estimates of oil and gas reserves. Significant rises or declines in product prices could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. Additionally, we perform impairment tests pursuant to Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, when significant events occur, such as a market move to a lower price environment or a material revision to our reserve estimates.

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

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

Oil and Gas Revenues

Revenues associated with sales of natural gas, crude oil, condensate and NGLs are recorded when title passes to the customer. Natural gas sales revenues from properties in which we have an interest with other producers are recognized on the basis of our net working interest ("entitlement" method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. Any amount received in excess of our share is treated as deferred revenues. If we take less than we are entitled to take, the under-delivery is recorded as a receivable. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, accruals for revenues and accounts receivable are made based on estimates of our share of production, particularly from properties that are operated by our partners. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results include estimates of production and revenues for the related time period. 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. Approximately 32 percent of natural gas and oil and condensate revenues for the three months ended March 31, 2006, related to two customers.

Natural Gas Midstream Revenues

Revenue from the sale of NGLs and residue gas is recognized when the NGLs and residue gas produced at the Partnership's 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 57 percent of natural gas midstream revenues for the three months ended March 31, 2006, related to three customers.

Coal Royalty Revenues

Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenues from those sales. Since the Partnership does not operate any mines, it does not have access to actual production and revenue information until approximately 30 days following the month of production. Therefore, the financial results of the Partnership include estimated revenues and accounts receivable for this 30-day period. Any differences, 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 and the Partnership have historically entered into derivative financial instruments that were expected to qualify for hedge accounting under 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 realized. The position reflected in the statement of income is based on the actual settlements with the counterparty. We include this gain or loss in oil and gas revenues, 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 non-cash derivative gain or loss recognized in revenue due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

Because a large portion of our natural gas derivatives and 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 commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we will recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, included in accumulated other comprehensive income will be reported in future earnings through 2008 as the original hedged transactions occur. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by mark-to-market gains and losses which fluctuate with volatile oil and gas prices.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well found a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At March 31, 2006, the costs attributable to unproved properties were approximately $65.8 million. We regularly assess on a property-by-property basis the impairment of individual unproved properties whose acquisition costs are relatively significant. Unproved properties whose acquisition costs are not relatively significant are amortized in the aggregate over the lesser of five years or the average remaining lease term. As exploration work progresses and the reserves on relatively significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be expensed. The timing of any writedowns of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, the Company and PVR operate with independent capital structures. The Company and PVR have separate credit facilities, and neither entity guarantees the debt of the other. Since the Partnership's inception in 2001, with the exception of cash distributions paid to us by PVR, the cash needs of each entity have been met independently with a combination of operating cash flows, credit facility borrowings and issuance of new Partnership units. We expect that our cash needs and the cash needs of PVR will continue to be met independently of each other with a combination of these funding sources. Summarized cash flow statements for three months ended March 31, 2006 and 2005, consolidating our combined segments are set forth below (in millions).

For the three months ended March 31, 2006	**Oil and Gas & Corporate**	**PVR Coal and PVR Midstream**	**Consolidated**
Cash flows from operating activities:			
Net income contribution	$ 22.0	$ 2.1	$ 24.1
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	21.0	19.7	40.7
Net change in operating assets and liabilities	9.4	(8.5)	0.9
Net cash provided by operating activities	52.4	13.3	65.7
Cash flows from investing activities:			
Additions to property and equipment	(41.3)	(5.5)	(46.8)
Acquisitions	(3.1)	(3.1)	(6.2)
Other	1.2	-	1.2
Net cash used in investing activities	(43.2)	(8.6)	(51.8)
Cash flows from financing activities:			
PVA dividends paid	(2.1)	-	(2.1)
PVR distributions received (paid)	6.4	(15.5)	(9.1)
PVA debt proceeds, net of repayments	(12.0)	-	(12.0)
PVR debt proceeds, net of repayments	-	(3.3)	(3.3)
Other	0.7	-	0.7
Net cash provided by (used in) financing activities	(7.0)	(18.8)	(25.8)
Net increase (decrease) in cash and cash equivalents	2.2	(14.1)	(11.9)
Cash and cash equivalents—beginning of period	2.7	23.2	25.9
Cash and cash equivalents—end of period	$ 4.9	$ 9.1	$ 14.0

For the three months ended March 31, 2005	**Oil and Gas & Corporate**	**PVR Coal and PVR Midstream**	**Consolidated**
Cash flows from operating activities:			
Net income contribution	$ 7.5	$ (0.5)	$ 7.0
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	17.8	18.3	36.1
Net change in operating assets and liabilities	(5.9)	(6.4)	(12.3)
Net cash provided by operating activities	19.4	11.4	30.8
Cash flows from investing activities:			
Additions to property and equipment	(37.3)	(0.3)	(37.6)
Acquisitions, net of cash acquired	—	(205.0)	(205.0)
Other	9.7	0.1	9.8
Net cash used in investing activities	(27.6)	(205.2)	(232.8)
Cash flows from financing activities:			
PVA dividends paid	(2.1)	—	(2.1)
PVR distributions received (paid)	4.6	(10.4)	(5.8)
PVA debt proceeds, net of repayments	2.0	—	2.0
PVR debt proceeds, net of repayments	—	80.3	80.3
Proceeds received from (paid for) the issuance of partners' capital	(2.5)	127.7	125.2
Other	0.5	(2.0)	(1.5)
Net cash provided by (used in) financing activities	2.5	195.6	198.1
Net increase (decrease) in cash and cash equivalents	(5.7)	1.8	(3.9)
Cash and cash equivalents—beginning of period	4.5	21.0	25.5
Cash and cash equivalents—end of period	$ (1.2)	$ 22.8	$ 21.6

Cash Flows

Except where noted, the following discussion of cash flows relates to our consolidated results.

From the three months ended March 31, 2005, to the three months ended March 31, 2006, the oil and gas and corporate segments' net cash provided by operations increased primarily due to increased natural gas production and increased prices received for natural gas and crude oil. We used cash from operating activities during both periods to help fund capital expenditures. Cash provided by operations of the coal and natural gas midstream segments increased primarily due to accretive cash flows from the natural gas midstream business, which PVR acquired in March 2005, and an increase in average royalties per ton resulting from higher coal sales prices.

Capital expenditures totaled $55.0 million for the three months ended March 31, 2006, compared with $249.9 million for the three months ended March 31, 2005. The following table sets forth capital expenditures by segment made during the periods indicated:

	Three Months Ended March 31,	
	2006	**2005**
	(in millions)	
Oil and gas		
Development drilling	$ 28.2	$ 24.6
Exploration drilling	9.9	7.3
Seismic	2.4	4.9
Lease acquisition and other	3.9	4.2
Pipeline, gathering, facilities	2.8	3.6
Total	47.2	44.6
Coal		
Acquisitions	2.7	9.3
Maintenance expenditures	0.1	0.1
Other property and equipment expenditures	2.1	-
Total	4.9	9.4
Natural gas midstream		
Acquisitions, net of cash acquired	-	195.7
Maintenance expenditures	0.6	0.2
Other property and equipment expenditures	2.0	-
Total	2.6	195.9
Other	0.3	-
Total capital expenditures	$ 55.0	$ 249.9

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

We expect oil and gas segment capital expenditures to be between $224 million and $244 million in 2006. We continually review drilling and other capital expenditure plans and may change the amount we spend in any area based on industry conditions and the availability of capital. We believe our cash flow from operations and sources of debt financing are sufficient to fund our 2006 planned oil and gas capital expenditures program.

During the three months ended March 31, 2006, PVR made aggregate capital expenditures of $7.5 million for coal reserve acquisitions, coal loadout facility construction and natural gas midstream gathering systems. PVR's cash flows from operations funded coal and natural gas midstream capital expenditures for the three months ended

March 31, 2006. To finance its acquisitions in the three months ended March 31, 2005, PVR borrowed $80.3 million, net of repayments, received proceeds of $125.2 million from the sale of its common units in a public offering and received a $2.5 million contribution from its general partner, which is a wholly owned subsidiary of the Company.

We repaid $12 million of our revolving credit facility in the three months ended March 31, 2006, compared to borrowings, net of repayments, of $2 million for the three months ended March 31, 2005. We also received cash distributions from PVR of $6.4 million in the three months ended March 31, 2006, compared to $4.6 million in the same period last year. Funds from both of these sources were primarily used for capital expenditures.

In April 2006, PVR announced a $0.35 per unit quarterly distribution for the three months ended March 31, 2006, or $1.40 per unit on an annualized basis. The distribution will be paid on May 15, 2006, to unitholders of record at the close of business on May 5, 2006. As a result of the 15.6 million limited partner units and incentive distribution rights we own as PVR's general partner, cash distributions we receive from PVR are expected to be approximately $25 million in 2006.

Long-Term Debt

Revolving Credit Facility. We have a revolving credit facility (the "Revolver") that is secured by a portion of our proved oil and gas reserves and matures in December 2010. We have a commitment of $200 million under the Revolver and a borrowing base of $300 million. We had $67 million outstanding under the Revolver as of March 31, 2006, giving us approximately $133 million of available borrowing capacity. The Revolver is governed by a borrowing base calculation and is redetermined semi-annually. We have the option to elect interest at (i) the London Interbank Offering Rate ("LIBOR") plus a Eurodollar margin ranging from 1.00 to 1.75 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin up to 0.50 percent. The Revolver allows for the issuance of up to $20 million of letters of credit.

The financial covenants under the Revolver require us to maintain levels of debt-to-earnings and impose dividend limitation restrictions. The Revolver contains various other 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 March 31, 2006, we were in compliance with all of our covenants under the Revolver.

Line of Credit. We have a $5.0 million line of credit with a financial institution, which had no borrowings against it as of March 31, 2006. The line of credit is effective through June 2006 and is renewable annually. We have an option to elect either a fixed rate LIBOR loan, a floating rate LIBOR loan or a base rate (as determined by the financial institution) loan.

PVR Revolving Credit Facility. As of March 31, 2006, PVR had $172.0 million outstanding under its $300 million revolving credit facility (the "PVR Revolver") that matures in March 2010. The PVR 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. PVR has a one-time option to expand the PVR Revolver by $150 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders. The PVR Revolver's interest rate fluctuates based on PVR's ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 1.00 percent if PVR selects the base rate borrowing option under the credit agreement or at a rate derived from LIBOR, plus an applicable margin ranging from 1.00 percent to 2.00 percent if PVR selects the LIBOR-based borrowing option.

The financial covenants under the PVR Revolver require PVR to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted PVR's additional borrowing capacity under the PVR Revolver to approximately $145.9 million as of March 31, 2006. The PVR Revolver prohibits PVR from making certain distributions, including distributions to unitholders if any potential default or event of default occurs or would result from such unitholder distributions. In addition, the PVR Revolver contains various covenants that limit, among other things, PVR's ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of PVR's business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in PVR's subsidiaries. As of March 31, 2006, PVR was in compliance with all of its covenants under the PVR Revolver.

PVR Senior Unsecured Notes. As of March 31, 2006, PVR owed $79.7 million under its senior unsecured notes (the "PVR Notes"). The PVR 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 PVR Notes contain various covenants similar to those contained in the PVR Revolver. The PVR Notes are equal in right of payment with all other unsecured indebtedness, including the PVR Revolver. As of March 31, 2006, PVR was in compliance with all of its covenants under the PVR Notes. The PVR Notes require PVR to obtain an annual confirmation of its credit rating, with a 1.00 percent increase in the interest rate payable on the PVR Notes in the event its credit rating falls below investment grade. In March 2006, PVR's investment grade credit rating was confirmed by Dominion Bond Rating Services.

Interest Rate Swaps. In September 2005, PVR 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 PVR Revolver until March 2010 (the "PVR Revolver Swaps"). PVR pays a fixed rate of 4.22 percent on the notional amount, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the PVR Revolver Swaps are recorded as interest expense. The PVR 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 March 31, 2006, the total interest rate on the $60 million portion of PVR Revolver borrowings covered by the PVR Revolver Swaps was 5.47 percent at March 31, 2006.

Future Capital Needs and Commitments

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

In 2006, we anticipate making oil and gas segment capital expenditures, excluding acquisitions, of between $224 and $244 million. These expenditures are expected to be funded primarily by operating cash flow. Additional funding will be provided as needed from our Revolver.

Part of PVR's strategy is to make acquisitions which increase cash available for distribution to its 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. PVR's ability to make these acquisitions in the future will depend in part on the availability of debt financing and on its ability to periodically use equity financing through the issuance of new common units, which will depend on various factors, including prevailing market conditions, interest rates and its financial condition and credit rating at the time.

PVR anticipates making capital expenditures, excluding acquisitions, in 2006 of $16 to $18 million for coal services projects and other property and equipment and $8 to $10 million for natural gas midstream system expansion projects. PVR believes that cash flow provided by operating activities, supplemented by borrowings against the PVR Revolver, will be sufficient to fund these capital expenditures.

Results of Operations

Selected Financial Data—Consolidated

	Three Months Ended March 31,	
	2006	2005
	(in millions, except per share data)	
Revenues	$ 200.9	$ 88.2
Expenses	$ 152.2	$ 60.5
Operating income	$ 48.7	$ 27.7
Net income	$ 24.1	$ 7.0
Earnings per share, basic	$ 1.29	$ 0.38
Earnings per share, diluted	$ 1.28	$ 0.38
Cash flows provided by operating activities	$ 65.7	$ 30.9

The increase in net income for the first quarter of 2005 compared to the first quarter of 2006 was primarily attributable to a $21.0 million increase in operating income and a $14.2 million decrease in non-cash derivative losses, partially offset by the related net increase in income tax expense. Operating income increased primarily due to increased natural gas revenues as a result of higher commodity prices and production volumes, and an increased contribution from our ownership in PVR, which is reported under the coal and natural gas midstream segments.

The assets, liabilities and earnings of PVR are fully consolidated in our financial statements, with the public unitholders' interest (59 percent, after effect of incentive distribution rights, as of March 31, 2006) reflected as a minority interest.

Oil and Gas Segment

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

Operations and Financial Summary – Oil and Gas Segment

Three Months Ended March 31, 2006, Compared with Three Months Ended March 31, 2005

	Three Months Ended March 31,		% Change	Three Months Ended March 31,	
	2006	**2005**		**2006**	**2005**
	(in millions, except as noted)			**(per Mcfe) (1)**	
Production					
Natural gas (billion cubic feet (“Bcf”))	6.7	5.9	14%		
Oil and condensate (thousand barrels)	91	85	7%		
Total production (Bcfe)	7.3	6.4	14%		
Revenues					
Natural gas					
Revenue received for production	60.3	$ 38.3	(57%)	$ 8.94	$ 6.48
Effect of hedging activities	(0.1)	(0.1)	-	(0.02)	(0.01)
Net revenue realized	60.2	38.2	58%	8.92	6.47
Oil and condensate					
Revenue received for production	5.0	3.7	35%	54.74	43.09
Effect of hedging activities	(0.2)	(0.3)	33%	(2.09)	(2.94)
Net revenue realized	4.8	3.4	41%	52.65	40.15
Other income	0.7	0.1	600%		
Total revenues	65.7	41.7	58%	9.01	6.50
Expenses					
Operating	5.0	3.1	61%	0.69	0.49
Taxes other than income	4.0	2.8	43%	0.55	0.44
General and administrative	2.5	1.8	39%	0.34	0.29
Production costs	11.5	7.7	49%	1.58	1.22
Exploration	7.9	7.7	3%	1.08	1.19
Depreciation, depletion and amortization	12.7	10.7	19%	1.73	1.66
Total expenses	32.1	26.1	23%	4.39	4.07
Operating income	$ 33.6	$ 15.6	115%	$ 4.62	$ 2.43

(1) Natural gas revenues are shown per Mcf, oil and condensate revenues are shown per barrel (“Bbl”), and all other amounts are shown per thousand cubic feet equivalent (“Mcfe”).

Production. The increase in production was primarily due to new production from increased drilling, including the horizontal CBM play in Appalachia, the Selma Chalk development play in Mississippi and the Cotton Valley play in east Texas and north Louisiana. Production from a new exploratory well drilled in 2005 in the Hackberry formation in south Texas also contributed to the increase. Production increases were partially offset by normal field declines.

Revenues. Approximately 93 percent and 92 percent of production in the three months ended March 31, 2006 and 2005, was natural gas. Increased natural gas production accounted for approximately $5.4 million, or 24 percent, of the increase in natural gas revenues. Increased realized prices for natural gas accounted for approximately $17.1 million, or 76 percent, of the increase in natural gas revenues. The increase in oil and condensate revenues is primarily attributable to increased realized prices.

Due to the volatility of crude oil and natural gas prices, we use derivatives to affect the price received for certain sales volumes through the use of swaps and costless collars. Gains and losses from derivative activities are included in net income when the related production occurs. In the first quarter of 2006, approximately 47 percent of our natural gas production used costless collars at an average floor price of $7.12 per million British thermal units ("MMbtu") and an average ceiling price of $12.07 per MMbtu. Approximately 27 percent of our crude oil production used costless collars with an average floor price of $48.20 per Bbl and an average ceiling price of $56.17 per Bbl. We recognized a loss on settled derivative contracts accounted for as cash flow hedges of $0.3 million in revenues in both the first quarter of 2006 and the first quarter of 2005. In addition, we recognized derivative gains for mark-to-market adjustments and ineffectiveness on oil and gas derivatives as described in Item 2, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Corporate and Other—Derivative Losses."

Expenses. The oil and gas segment's aggregate operating costs and expenses in the first quarter of 2006 increased due to increases in operating expenses, taxes other than income, general and administrative expenses and depreciation, depletion and amortization ("DD&A") expenses. These increases were partially offset by a decrease in exploration expense.

Operating expenses increased primarily due to additional compressor rentals at fields with increased production, downhole maintenance charges associated with horizontal CBM wells in Appalachia and Selma Chalk wells in Mississippi, increased surface repair costs and increased gathering fees related to horizontal CBM and Cotton Valley wells.

Taxes other than income increased due to higher severance taxes as a result of increased production and higher gas prices. General and administrative expenses increased primarily due to increased payroll costs as a result of wage increases and new personnel.

Exploration expenses for the three months ended March 31, 2006 and 2005, consisted of the following (in millions):

	Three Months Ended March 31,	
	2006	**2005**
Dry hole costs	$ 3.2	$ 2.2
Seismic	2.4	4.9
Unproved leasehold write-offs	1.2	0.3
Other	1.1	0.3
Total	$ 7.9	$ 7.7

Exploration expenses for the first quarter of 2006, were similar in total to exploration expenses for the first quarter of 2005. Increases in dry hole costs and unproved leasehold write-offs were offset by decreased seismic expenses. We wrote off costs incurred in the first quarter of 2006 related to an exploratory well that had been determined to be unsuccessful in the fourth quarter of 2005 and another exploratory well that was determined to be unsuccessful subsequent to March 31, 2006. In the first quarter of 2005, we wrote off four exploratory wells that had been under evaluation. Increased unproved leasehold write-offs and other exploration expense increased primarily due to the amortization of unproved property pools and increased delay rentals. The timing of seismic data purchases in the first quarter of 2006 caused seismic expenses to decrease compared to the first quarter of 2005.

Oil and gas DD&A expenses increased due to the 14 percent increase in equivalent production and as a result of higher average depletion rates. The average depletion rate increased from $1.67 per Mcfe in the first quarter of 2005 to $1.74 per Mcfe in the first quarter of 2006 as a result of a greater percentage of production coming from relatively higher cost horizontal CBM and Cotton Valley wells and general price inflation for equipment, services and tubulars used for drilling and development.

Coal Segment

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

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

Operations and Financial Summary – Coal Segment

Three Months Ended March 31, 2006, Compared with Three Months Ended March 31, 2005

	Three Months Ended March 31,		
	2006	**2005**	**% Change**
Financial Highlights	**(in millions, except as noted)**		
Revenues			
Coal royalties	$ 22.4	$ 18.1	24%
Coal services	1.4	1.3	8%
Other	1.5	0.4	275%
Total revenues	25.3	19.8	28%
Expenses			
Operating	1.0	1.0	-
Taxes other than income	0.3	0.3	-
General and administrative	2.2	2.4	(8%)
Operating expenses before non-cash charges	3.5	3.7	(5%)
Depreciation, depletion and amortization	4.7	3.8	24%
Total expenses	8.2	7.5	9%
Operating income	$ 17.1	$ 12.3	39%
Operating Statistics			
Royalty coal tons produced by lessees (tons in millions)	7.7	6.7	15%
Average royalty per ton ($/ton)	$2.90	$ 2.69	8%

Revenues. Coal royalty revenues increased due to a higher average royalty per ton and increased production. The average royalty per ton increased to $2.90 in the first quarter of 2006 from $2.69 in the first 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 PVR's lessees increased primarily due to new production on PVR's Illinois Basin property, which it acquired in the third quarter of 2005.

Other revenues increased primarily due to the following factors. In the three months ended March 31, 2006, PVR received approximately $0.4 million in revenues for the management of certain coal properties, approximately $0.2 million of rental income from railcars purchased in the second quarter of 2005 and approximately $0.1 million of royalty income from oil and natural gas royalty interests acquired in March 2005. PVR also received approximately $0.2 million of additional wheelage fees in the three months ended March 31, 2006, primarily as a result of an April 2005 acquisition.

Expenses. Operating expenses did not increase despite the increase in production because production on PVR's subleased properties decreased by 29 percent to 0.8 million tons in the first quarter of 2006 due to the movement of longwall mining operations at one of these properties. DD&A expense increased due to the increase in production and a higher depletion rate on reserves acquired in 2005.

Natural Gas Midstream Segment

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

The PVR 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 PVR 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 generally 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 – PVR Midstream Segment

Three Months Ended March 31, 2006, Compared with Three Months Ended March 31, 2005

	Three Months Ended March 31,		Three Months Ended March 31,	
	2006	**2005 (1)**	**2006**	**2005 (1)**
	(in millions, except as noted)		(per Mcf)	
Financial Highlights				
Revenues				
Residue gas	$ 78.5	$ 17.0		
Natural gas liquids	28.0	8.3		
Condensate	2.3	-		
Gathering and transportation fees	0.4	1.0		
Total natural gas midstream revenues	109.2	26.3		
Marketing revenue, net	0.6	0.1		
Total revenues	109.8	26.4	$ 9.11	$ 6.75
Expenses				
Cost of midstream gas purchased	98.7	21.9	8.18	5.59
Operating	2.5	0.8	0.21	0.20
Taxes other than income	0.4	0.1	0.03	0.03
General and administrative	3.0	0.4	0.25	0.11
Depreciation and amortization	4.1	1.2	0.34	0.31
Total operating expenses	108.7	24.4	9.01	6.24
Operating income	$ 1.1	$ 2.0	$ 0.10	$ 0.51
Operating Statistics				
Inlet volumes (Bcf)	12.1	3.9		
Midstream processing margin (2)	$ 10.5	$ 4.4	$ 0.87	$ 1.14

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

(2) Midstream processing margin consists of total natural gas midstream revenues minus the cost of midstream gas purchased. Excluding the effect of a $4.6 million non-cash reserve charge, the midstream processing margin per Mcf for the three months ended March 31, 2006, would have been $1.25 per Mcf.

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 PVR's gas processing plants and the purchase and resale of natural gas not connected to PVR's gathering systems and processing plants. The increase in average realized sales price from $6.75 per Mcf in the first quarter of 2005 to $9.11 per Mcf in the first quarter of 2006 is consistent with overall market increases in NGL and natural gas prices.

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

Cost of midstream 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 gas from $5.59 in the first quarter of 2005 to $8.18 in the first quarter of 2006 is primarily due to overall market increases in natural gas prices. Included in cost of midstream gas purchased for the three months ended March 31, 2006, was a $4.6

million non-cash charge to reserve for amounts related to balances assumed as part of the Cantera Acquisition for which the possibility of collection is still being evaluted by PVR. Excluding this non-cash charge, the midstream processing margin per Mcf would have been $1.25 per Mcf, an increase of seven percent from $1.13 in the first quarter of 2005.

General and administrative expenses per Mcf increased from $0.11 in the first quarter of 2005 to $0.25 in the first quarter of 2006, primarily due to increased reimbursement to the general partner for corporate overhead costs.

Corporate and Other

Corporate and other results primarily consist of oversight and administrative functions.

Expenses. Corporate operating expenses increased $0.8 million from $2.5 million in the first quarter of 2005 to $3.3 million in the first quarter of 2006. The increase was primarily related to increased general and administrative expenses which included higher payroll costs as a result of wage increases, new personnel and the recognition of stock option expense upon adoption of Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*.

Interest Expense. Interest expense increased primarily due to interest incurred on additional borrowings under the PVR Revolver to finance 2005 acquisitions. We capitalized interest costs amounting to $0.4 million and $0.6 million in the quarters ended March 31, 2006 and 2005, because the borrowings funded the preparation of unproved properties for their intended use.

Derivative Losses. Non-cash derivative losses of $0.2 million for the three months ended March 31, 2006, consisted of a $5.9 million gain on oil and gas segment derivatives and a $6.1 million loss on natural gas midstream derivatives. The derivative losses primarily resulted from mark-to-market adjustments on certain derivatives that no longer qualified for hedge accounting. The $14.3 million in derivative losses for the three months ended March 31, 2005, primarily represented the change in the 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. Beginning in the first quarter of 2006, changes in market value of the derivative agreements are charged to earnings.

For the three months ended March 31, 2006, in addition to the $0.2 million derivative losses discussed above, we recognized a net derivative loss of $1.0 million which is reflected primarily in natural gas midstream revenues, natural gas revenues, oil and condensate revenues and cost of midstream gas purchased. We made net cash disbursements of $3.3 million on derivative settlements during the three months ended March 31, 2006.

Environmental

Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment and otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

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

As of March 31, 2006 and 2005, the Partnership's environmental liabilities included $2.4 million and $1.5 million, which represents the Partnership's best estimate of the liabilities as of those dates related to the coal and natural gas midstream businesses. The Partnership has 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 first quarter of 2006 are expected to have a material effect on our consolidated financial position, results of operations or cash flows. See Note 2 in the Notes to Consolidated Financial Statements for a discussion of new accounting standards adopted in the first quarter of 2006.

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:

- the cost of finding and successfully developing oil and gas reserves;
- our ability to acquire new oil and gas reserves and the price for which such reserves can be acquired;
- energy prices generally and the specific and relative prices of crude oil, natural gas, NGLs and coal;
- the volatility of commodity prices for crude oil, natural gas, NGLs and coal;
- the projected supply of and demand for crude oil, natural gas, NGLs and coal;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production;
- availability of required drilling rigs, materials and equipment;
- non-performance by third party operators in wells in which we own an interest;
- competition among producers in the oil and natural gas, coal and natural gas midstream industries generally;
- the extent to which the amount and quality of actual production of our oil and natural gas or PVR's coal differs from estimated recoverable proved oil and gas reserves and coal reserves;
- PVR's ability to make cash distributions to its general partner and its unitholders;
- hazards or operating risks incidental to our business and to PVR's coal or midstream business;
- PVR's ability to continually find and contract for new sources of natural gas supply for its midstream business;
- PVR's ability to retain its existing or acquire new midstream customers;
- PVR's ability to acquire new coal reserves and the price for which such reserves can be acquired;
- PVR's ability to lease new and existing coal reserves;
- the ability of PVR's lessees to produce sufficient quantities of coal on an economic basis from PVR's reserves;
- unanticipated geological problems;
- the occurrence of unusual weather or operating conditions including force majeure events;
- the failure of equipment or processes to operate in accordance with specifications or expectations;
- delays in anticipated start-up dates of our oil and natural gas production and PVR's lessees' mining operations;

- environmental risks affecting the drilling and producing of oil and gas wells, the mining of coal reserves or the production, gathering and processing of natural gas;
- the timing of receipt of necessary governmental permits by us and by PVR or PVR's lessees;
- the risks associated with having or not having price risk management programs;
- labor relations and costs;
- accidents;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators;
- 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 PVR's coal lessees and midstream customers;
- changes in financial market conditions; 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 PVR's lessees. If our customers or PVR's 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 anticipated production. 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. During the first quarter of 2006, we reported a $0.2 million derivative loss for mark-to-market adjustments on certain derivatives that no longer qualified for hedge accounting effective January 1, 2006. See the discussion and tables in Note 4 in the Notes to Consolidated Financial Statements for a description of our hedging program and a listing of open derivative agreements and their fair value as of March 31, 2006.

Because a large portion of our natural gas derivatives and 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 commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we will recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, included in accumulated other comprehensive income will be reported in future earnings through 2008 as the original hedged transactions occur. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by mark-to-market gains and losses which fluctuate with volatile oil and gas prices.

Interest Rate Risk

As of March 31, 2006, we had $67 million of long-term debt outstanding under the Revolver. The Revolver matures in December 2007 and is governed by a borrowing base calculation that is re-determined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.00 percent to 1.75 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin up to 0.50 percent. As a result, our interest costs will fluctuate based on short-term interest rates relating to our Revolver.

As of March 31, 2006, the Partnership's $172.0 million of outstanding indebtedness under the PVR Revolver carried a variable interest rate throughout its term. The Partnership executed interest rate derivative transactions in September 2005 to effectively convert the interest rate on $60 million of the amount outstanding under the PVR Revolver from a LIBOR-based floating rate to a 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 March 31, 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 March 31, 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 PVR 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 of Part II are not applicable and have been omitted.

Item 6 ***Exhibits***

10.1	Third Amendment to Amended and Restated Credit Agreement dated as of April 14, 2006 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A.
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 CORPORATION

Date:	May 9, 2006	By:	/s/ Frank A. Pici Frank A. Pici Executive Vice President and Chief Financial Officer
Date:	May 9, 2006	By:	/s/ Forrest W. McNair Forrest W. McNair Vice President and Controller