PENN VIRGINIA CORPORATION

2007 Annual Report

Core Oil & Gas Producing Areas

1. East Texas / Cotton Valley

Cotton Valley / Bossier Shale Potential

2. Mid-Continent

Hartshorne Horizontal CBM (HCBM) and Granite Wash / Fayetteville and Woodford-Caney Shale Exploration

3. Mississippi / Selma Chalk

Selma Chalk Development

4. Appalachia

Multi-Lateral HCBM Development / Devonian (Lower Huron and Marcellus) Shale Potential

5. Gulf Coast

Onshore Conventional Oil and Gas Exploration and Development

Headquartered in Radnor, PA and a member c
Penn Virginia Corporation (NYSE: PVA) is an i
focused on the exploration, acquisition, devel
domestic onshore regions. PVA also owns app
GP Holdings, L.P. (NYSE: PVG), the owner of the general partner and the largest unit holder of Penn Virginia Resource Partners, L.P. (NYSE: PVR), a manager of coal and natural resource properties and related assets and the operator of a midstream natural gas gathering and processing business. For more information about PVA, please visit its website at www.pennvirginia.com.

Financial Highlights

(in millions except per share data)	2007	2006	2005	2004	2003
Financial Data					
Net revenues [1]	$ 509.7	$ 419.3	$ 370.0	$ 228.4	$ 181.3
Operating income	192.6	170.5	162.0	80.8	62.1
Net income	50.8	75.9	62.1	33.4	28.5
Net cash flows provided by operating activities	313.0	275.8	231.4	146.4	109.7
Common Share Data [2]					
Net income, basic ($/share)	$ 1.33	$ 2.03	$ 1.67	$ 0.91	$ 0.80
Net income, diluted ($/share)	1.32	2.01	1.66	0.91	0.79
Dividends paid ($/share)	0.23	0.23	0.23	0.23	0.23
Average shares outstanding, diluted	38.4	37.7	37.5	36.9	36.2
Capitalization					
Long-term debt, excluding current portion	$ 751.2	$ 428.2	$ 325.8	$ 188.9	$ 154.3
Minority interest in subsidiaries	179.2	438.4	313.5	182.9	190.5
Shareholder's equity	810.0	382.4	310.3	252.9	211.6
Total capitalization	1,740.4	1,249.0	949.6	624.7	556.4
Long-term debt as percent of total capitalization	43%	34%	34%	30%	28%
Production Data					
Total oil and gas production (Bcfe)	40.6	31.3	27.4	24.5	23.8
Oil and condensate (Mbbls)	461	382	302	396	625
Natural gas (Bcf)	37.8	29.0	25.6	22.1	20.1
Daily production (MMcfe)	111.1	85.6	75.0	66.8	65.2
Coal produced by lessees (millions of tons)	32.5	32.8	30.2	31.2	26.5
System throughtput volumes (MMcfd) [3]	186	170	144	—	—
Estimated Reserves					
Total proved oil and gas reserves (Bcfe)	680	487	377	354	322
Coal (millions of recoverable tons)	818	765	689	558	588
Realized Prices and Margins					
Oil and condensate ($/Bbl)	$ 60.97	$ 55.59	$ 45.67	$ 33.75	$ 26.91
Natural gas ($/Mcf)	6.94	7.35	8.31	6.27	5.31
Coal royalties ($/ton)	2.89	2.99	2.74	2.23	1.90
Midstream processing margin ($/Mcf)	1.33	1.10	1.02	—	—

(1) 2007, 2006 and 2005 revenues are shown net of cost of gas purchased.
(2) Amounts per common share have been adjusted for the effect of two for one stock splits in June 2004 and June 2007
(3) 2005 data reflects system throughput volumes from March 3, 2005, the commencement date of midstream operations

Dear Fellow Shareholders

2007 was a year of major accomplishments for Penn Virginia Corporation (PVA). Our oil and gas exploration and production (E&P) business achieved record levels of production and proved reserves. We experienced growth in all five of our core operating areas, led by contributions from the Cotton Valley play in east Texas, the Selma Chalk play in Mississippi and various plays in the Mid-Continent region.

We are pleased to report that 2007 was another record year for PVA operationally and financially. We set new company records in a number of categories, including:

- Oil and natural gas production increased 30 percent to a record 40.6 Bcfe
- Proved oil and gas reserves were up 40 percent to a record 680 Bcfe
- Reserve replacement was 628 percent at a cost of $2.04 per Mcfe
- Operating income increased 13 percent over 2006 to $192.6 million
- Cash flow from operating activities increased 13 percent over 2006 to a record $313.0 million

During 2007, E&P capital expenditures, excluding acquisitions, were approximately $378 million which funded our record production and proved reserve growth. In addition, approximately $142 million of reserve and leasehold acquisitions were completed during the year, further adding to reserves and future development and exploration drilling locations.

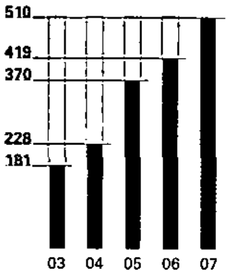
Our inventory of largely low-risk, unconventional development drilling opportunities is expected to provide proved reserve growth at attractive reserve replacement costs. We expect to continue to supplement our proved reserve growth with complementary acquisitions. In addition, we expect to continue to expand the application of horizontal drilling in the Selma Chalk in Mississippi and the Granite Wash in Oklahoma, as well as to explore various shale play opportunities, including the Devonian / Marcellus Shale in Appalachia, the Bossier Shale in East Texas and a number of shale plays in the Mid-Continent region.

To help fund our continuing growth strategy, in December 2007, we successfully completed the first follow-on public offering of convertible debt and equity securities in our 125-year history, raising approximately $372 million of capital. The net proceeds of the offering were used to repay bank debt, which significantly increased our liquidity.

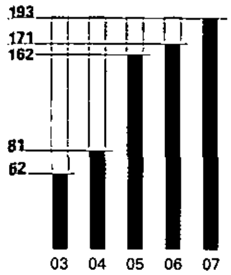
In addition to the growth experienced in the E&P segment, we are pleased to report that the coal and natural resource management (NRM) and natural gas midstream segments operated by Penn Virginia Resource Partners, L.P. (NYSE: PVR) set records for operating income and distributable cash flow. Penn Virginia GP Holdings, L.P. (NYSE: PVG), which we took public in December 2006 and which holds our ownership interests in PVR, also had a successful first year in 2007 in terms of distribution growth and unit price appreciation. At December 31, 2007, the value of our 82 percent ownership in PVG was $919 million, an increase of 44 percent during 2007, and the latest annualized run rate for distributions received from PVG was approximately $41 million, up 36 percent from the distribution level contemplated during PVG's initial public offering (IPO). The distributions we expect from PVG will continue to be an important source of cash to help finance our E&P activities.

In the PVR Coal and NRM segment, coal reserves increased by 53 million tons to 818 million tons, replacing 263 percent of the 32.5 million tons produced by lessees during 2007. In addition, in the second half of 2007, PVR completed approximately $124 million in acquisitions of Appalachian forestland and oil and gas royalties, significantly expanding existing business lines and providing a larger, more diversified cash flow stream within the segment. In the PVR natural gas midstream segment, system throughput volumes increased nine percent

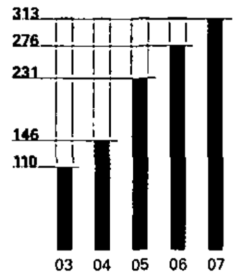
Net Revenues
(dollars in millions)



Operating Income
(dollars in millions)



Cash Flow From Operations
(dollars in millions)



40% increase
in proved reserves

30% increase
in oil & gas production

Record operating income of
$193 million

and the gross processing margin increased 32 percent. By April 2008, PVR expects to bring on line two processing plants, the first in the panhandle of Texas, serving third party gas producers, and the second in East Texas, processing our Cotton Valley production, as well as third-party gas.

We look forward to continued growth in 2008 across all of our business segments. In our E&P business, we will continue to capitalize on our expertise in unconventional plays. We also have a number of relatively lower-risk, exploratory plays primarily in Appalachia, the Williston Basin and the Mid-Continent that, if successful, would provide additional development growth opportunities. Our 2008 oil and gas business capital budget is $475 million, a 26 percent increase over the $378 million of capital expenditures in 2007, excluding acquisitions. Approximately 87 percent of this amount is earmarked to develop reserves in our four core areas of East Texas, Mid-Continent, Mississippi and Appalachia. We expect to focus exploration spending on various shale plays in a number of our core areas and also on our Gulf Coast prospect areas in south Louisiana

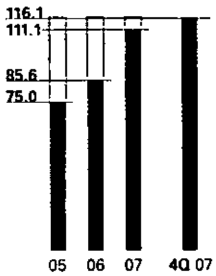
and south Texas, which we believe provide the potential for meaningful reserve and production additions.

As always, we greatly appreciate the hard work and dedication of our employees and the continued loyalty and support of our shareholders.

Robert Garrett
Chairman

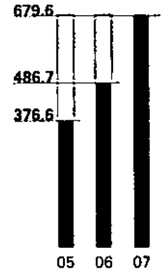
A. James Dearlove
President and Chief Executive Officer

Oil & Gas Production
(MMcfe/d)



2007 PRODUCTION	(Bcfe)	% Total
E. Texas / Cotton Valley	8.0	20%
Mid-Continent	4.1	10%
Miss. / Selma Chalk	7.6	19%
Appalachia	12.4	30%
Gulf Coast	8.5	21%
Totals	**40.6**	**100%**

Proved Oil & Gas Reserves (Bcfe)



12/31/2007 PROVED OIL & GAS RESERVES	(Bcfe)	% Total
E. Texas / Cotton Valley	292.2	43%
Mid-Continent	79.6	12%
Miss. / Selma Chalk	138.6	20%
Appalachia	133.3	20%
Gulf Coast	35.9	5%
Totals	**679.6**	**100%**

Oil & Gas

H. Baird Whitehead
PVA Executive Vice President
President of Penn Virginia Oil & Gas Corporation

2007 was another record year for our oil and gas exploration and production (E&P) segment in terms of production and reserve growth. We intend to build on this success in 2008 as evidenced by our announced capital expenditures budget of $475 million, excluding acquisitions.

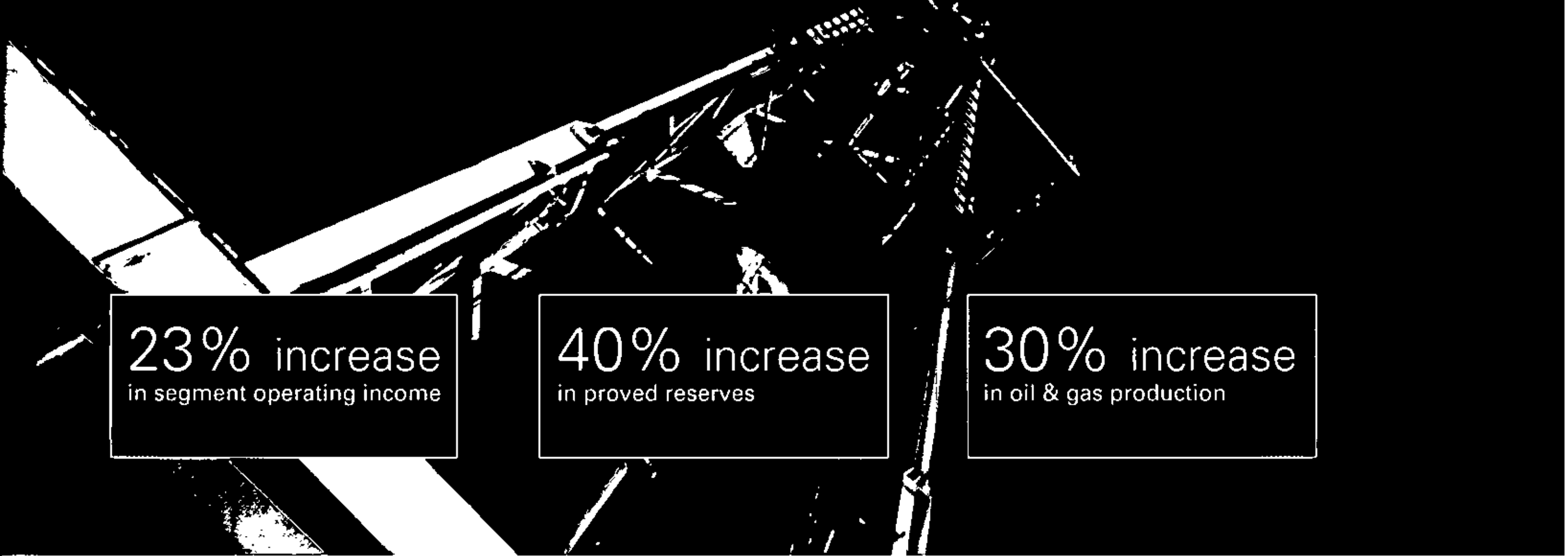
During 2007, we enjoyed strong growth from our East Texas Cotton Valley, Mid-Continent, Mississippi Selma Chalk and Appalachian horizontal coalbed methane (HCBM) development drilling, as well as from successful exploration in the Gulf Coast. We also completed acquisitions totaling 74.4 Bcfe of proved reserves in East Texas, the Mid-Continent region and Mississippi and divestitures of 21.5 Bcfe of proved reserves in Appalachia.

Our strategy is to continue to focus on relatively lower-risk, unconventional natural gas oriented resource plays in our core areas. We will also continue our exploration program (approximately 13 percent of the 2008 capital expenditures budget), which could provide us with meaningful increases in our production and proved reserves. The relatively lower-risk plays include the Cotton Valley program in East Texas, the Selma Chalk in Mississippi, HCBM in Appalachia, and HCBM and Granite Wash in the Mid-Continent. We are also assessing the potential of various shale plays, including the Bossier Shale in East Texas, the Lower Huron and Marcellus Devonian-age Shales in Appalachia, and the Fayetteville and Woodford-Caney Shales in the Mid-Continent region.

Our increased E&P operating income and cash flows in 2007 were the direct result of record drilling activity, which also led to impressive reserve and production growth:

- We drilled 289 wells during 2007, including 271 development wells and 18 exploratory wells. All but six of the development wells were successful, with 11 successful exploratory wells and four under evaluation, for a 97 percent overall success rate.
- Oil and gas production in 2007 was 40.6 Bcfe, a new record which eclipsed the 31.3 Bcfe in 2006 by 30 percent. We expect production to grow significantly again in 2008.
- Our estimated proved reserves at the end of 2007 were a record 680 Bcfe, up 40 percent from 487 Bcfe at the end of 2006, including reserves added in acquisitions. Natural gas comprised approximately 87 percent of year-end proved reserves, and 59 percent of reserves were proved developed. Net of revisions, we added approximately 255 Bcfe of proved reserves primarily via the drillbit (71 percent), replacing approximately 628 percent of 2007 production.

Remaining consistent with our strategy to exploit our expertise in relatively lower-risk, unconventional plays, approximately 87 percent of the 2008 capital expenditures budget is devoted to drilling 330 wells in our core development areas. We also plan to spread our exploration spending among projects in the Gulf Coast and in most of our other core areas. We do not budget acquisitions, but continuously review opportunities which would complement our strategy. As part of our strategy, we employ commodity hedges to protect our budgeted cash flow.



Horizontal Drilling and Emerging Shale Plays in Multiple Regions

OVERVIEW

Beyond our core development plays, which include vertical Cotton Valley wells in East Texas, multi-lateral horizontal coalbed methane (HCBM) wells in Appalachia, Selma Chalk wells in Mississippi, and Hartshorne HCBM and Granite Wash wells in Oklahoma, we have additional upsides for future growth from horizontal drilling applications within some of these development plays, as well as from new shale plays across the U.S. For example, in 2008 and beyond, we are shifting development in the Selma Chalk and Granite Wash plays from vertical to horizontal drilling. In addition, we are actively exploring or have near-term plans to explore shale plays in Appalachia, the Mid-Continent region and East Texas.

HORIZONTAL DRILLING APPLICATIONS

We have had significant horizontal drilling success since 2002 with our Appalachian HCBM play and since 2006 with our Mid-Continent Hartshorne HCBM play. In other development plays, such as the Selma Chalk and Granite Wash, consideration has been given recently to shifting from vertical to horizontal drilling. One of the primary reasons for shifting to horizontal drilling is that it is often a superior way to more efficiently drain a reservoir for less cost and with less disturbance to the surface area than vertical infill drilling. A number of vertical wells can effectively be replaced by a single horizontal lateral, increasing production and reserves on a more efficient and economical basis. In addition, horizontal drilling can allow for greater downspacing within a given reservoir than would be possible in the near-term with vertical drilling. Thus far, we have had success with the transition to horizontal drilling in the Selma Chalk and Granite Wash plays, and we plan to dedicate increasing amounts of capital to fund these efforts and increase production and reserve growth.

APPALACHIAN SHALE PLAYS

Over the past two plus years, given the success of a number of shale plays in the Fort Worth and Arkoma Basins, interest has grown in establishing similar results with Devonian-age shales in Appalachia. In particular, the Marcellus Shale and Lower Huron Shale have garnered strong attention. We have acreage which we believe to be prospective for Appalachian shale play reserves and intend to increase our shale acreage in both West Virginia and Pennsylvania. We have drilled a small number of Lower Huron wells to date, with some success, and plan to drill additional test wells in 2008 and beyond to determine the extent and location of our prospective areas for both shale types.

MID-CONTINENT SHALE PLAYS

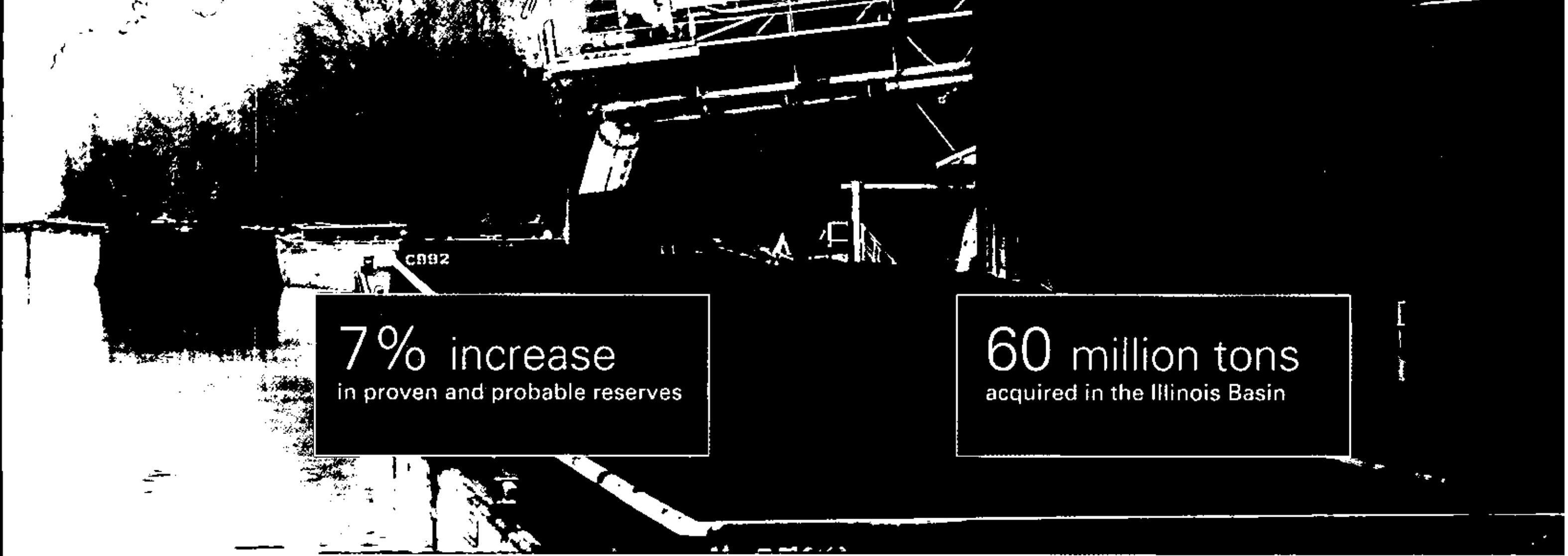
We entered the Mid-Continent region in 2006 and have acquired additional acreage in the Arkoma and Anadarko Basins of Oklahoma and Arkansas which may be prospective for the Fayetteville Shale and Woodford-Caney Shales. In addition, we have acreage in North Dakota which may be prospective for the oily Bakken Shale play. We have actively explored the Fayetteville Shale in Arkansas, with mixed success to date. In 2008, we plan to begin to explore the Woodford-Caney Shales in both the Arkoma and Anadarko Basins of Oklahoma. In addition, in 2008, we plan to begin to explore the Bakken Shale in North Dakota.

EAST TEXAS SHALE PLAY

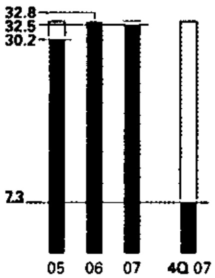
A primary development area for us is the Cotton Valley play in East Texas and North Louisiana. Underlying the Cotton Valley sands are the Bossier Shales, through which we have drilled and completed approximately fifteen vertical wells over the past two years. Due to the results of those vertical completions, the prevalence of the shales throughout our leasehold position, the expected gas in place and a number of technical factors, we will initiate an exploration program in 2008 using horizontal drilling in the shale.

CONCLUSION

The presence of shale play reserve potential and a shift to horizontal drilling in a number of our key operating areas provides potential significant upsides that we will begin to explore during 2008.



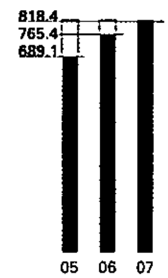
Coal Produced by PVR's Lessees
(Tons in millions)



2007

COAL PRODUCTION	(MM tons)	%Total
Central Appalachia	18.8	58%
Illinois Basin	3.8	12%
Northern Appalachia	4.2	13%
San Juan Basin	5.7	17%
Totals	**32.5**	**100%**

Proven and Probable Coal Reserves
(Tons in millions)



12/31/2007

COAL RESERVES	(MM tons)	%Total
Central Appalachia	569.3	69%
Illinois Basin	168.5	21%
Northern Appalachia	29.7	4%
San Juan Basin	50.9	6%
Totals	**818.4**	**100%**

Coal and Natural Resource Management

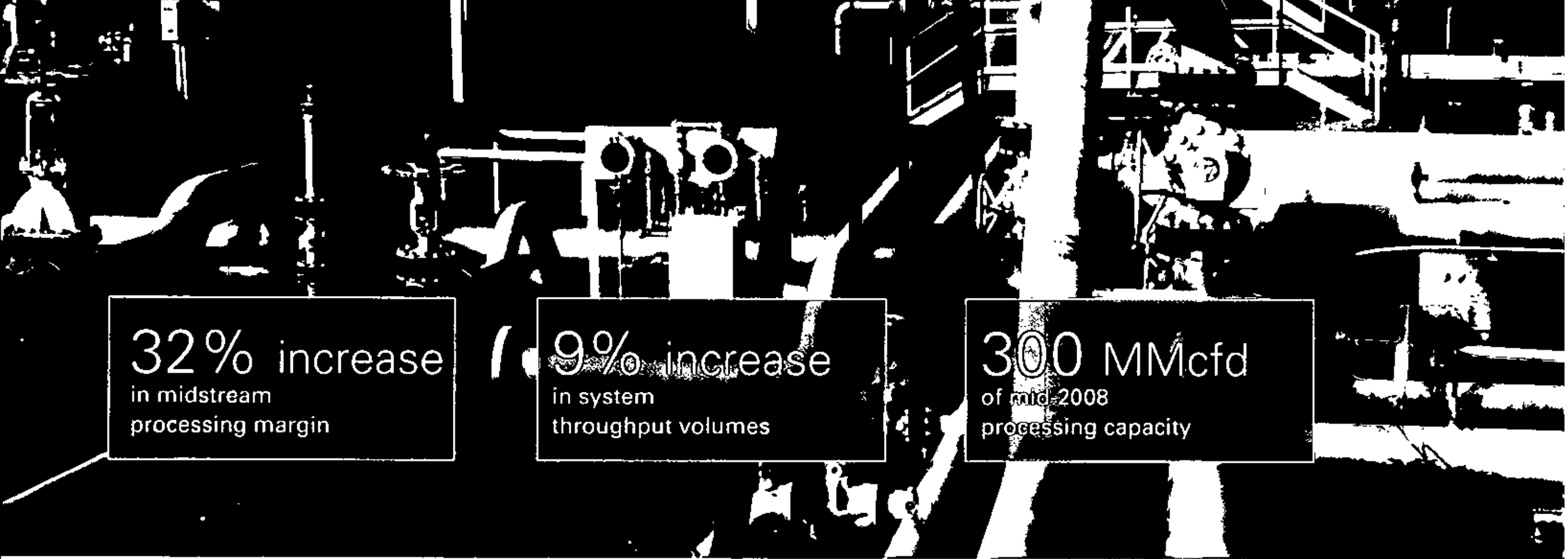
Through PVR's Coal and Natural Resource Management segment, PVR owned or controlled approximately 818 million tons of proven and probable coal reserves as of December 31, 2007, an increase of seven percent from the prior year level. PVR's reserves are located in Central Appalachia, the Illinois Basin, Northern Appalachia and the San Juan Basin. Coal production by PVR's lessees was 32.5 million tons in 2007, relatively flat from the 32.8 million tons in 2006.

PVR completed two coal reserve acquisitions during 2007, adding approximately 60 million tons of coal in the Illinois Basin for a total acquisition cost of approximately $52 million. These acquisitions complemented the approximate 116 million tons of western Kentucky coal reserves PVR purchased in 2005 and 2006. PVR believes that production from the Illinois Basin will accelerate as environmental regulations become more stringent and as technological advances make it environmentally acceptable to use the basin's high sulfur coal.

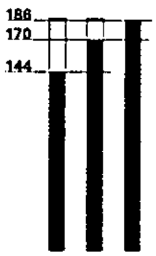
In the second half of 2007, PVR completed acquisitions of forestland and oil and gas royalties in Appalachia for approximately $124 million, which expanded and diversified its existing natural resource management businesses. Together with the coal services and infrastructure business, the revenues of which grew 24 percent in 2007, PVR plans to continue to expand its natural resource management businesses in the future to supplement growth in the coal land management business.

In 2007, approximately 81 percent of the coal produced from PVR's properties was subject to leases which required its lessees to pay royalties based on the higher of a fixed base price or a percentage of the gross sales price they received for selling the coal. Most of that coal is sold by PVR's lessees under long-term contracts. The royalties PVR received on the other 19 percent of coal produced from PVR's properties were based on fixed rates per ton, which escalate annually. PVR's average royalty rates in 2007 decreased three percent to $2.89 per ton from $2.99 per ton in 2006 primarily due to a shift in the mix of production in 2007 as compared to 2006, with higher lessee production in the Illinois and San Juan Basins, which have lower average royalties per ton, partially offset by lower lessee production in Central Appalachia, which has higher average royalties per ton.

Coal prices increased in the fourth quarter of 2007 and they have remained strong in early 2008, due to increased worldwide and domestic demand for coal and other hydrocarbons. PVR believes that the increase in coal prices will benefit its lessees during 2008 as many of them will enter into new long-term contracts in 2008.



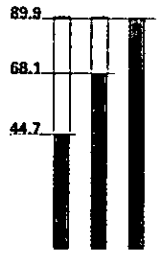
System Throughput Volumes (MMcf per day)



2007

THROUGHPUT VOLUMES	(MMcfd)	%Total
Beaver System	146	78%
Crescent System	20	11%
Hamlin System	7	4%
Arkoma System	13	7%
Totals	**186**	**100%**

Gross Midstream Processing Margin[a]
(Dollars in millions)



Mid-2008

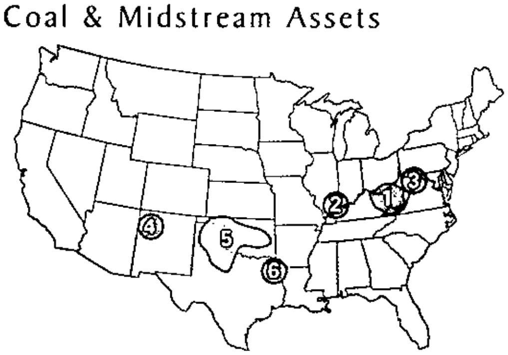
PROCESSING CAPACITY[b]	(MMcfd)	%Total
Beaver / Spearman	160	53%
Crescent	40	13%
Hamlin	20	7%
Crossroads	80	27%
Totals	**300**	**100%**

(a) 10-month data for 2005
(b) Includes 140 MMcfd of capacity to be added in 2008

Natural Gas Midstream

Through PVR Midstream, PVR owns and operates natural gas midstream assets that include approximately 3,700 miles of natural gas gathering pipelines and three natural gas processing plants, which have 160 million cubic feet per day (MMcfd) of total capacity. By April 2008, PVR expects to add an additional 140 MMcfd of capacity at two natural gas processing plants, including one in east Texas with 80 MMcfd capacity which will process most of our liquids-rich Cotton Valley gas production. The east Texas plant is the latest step in our continuing strategy to create synergies between PVR Midstream and our oil and gas segment.

Coal & Midstream Assets



1. **Central Appalachia Coal Reserves & Infrastructure**
2. **Illinois Basin Coal Reserves and Infrastructure**
3. **Northern Appalachia Coal Reserves**
4. **San Juan Basin Coal Reserves**
5. **Mid-Continent Natural Gas Midstream Operations**
6. **East Texas Natural Gas Midstream Operations**

PVR Midstream derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing related services. PVR Midstream also operates a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

During 2007, system throughput volumes at PVR's gas processing plants and gathering systems, including gathering-only volumes, were 67.8 Bcf, or approximately 186 MMcfd, a nine percent increase over 170 MMcfd average in 2006. PVR's gross processing margin increased to $89.9 million, or $1.33 per Mcf, for 2007 from $68.1 million, or $1.10 per Mcf, in 2006 as a result of record "frac spreads." Midstream operating income in 2007 was $48.9 million, up 67 percent from $29.4 million in 2006.

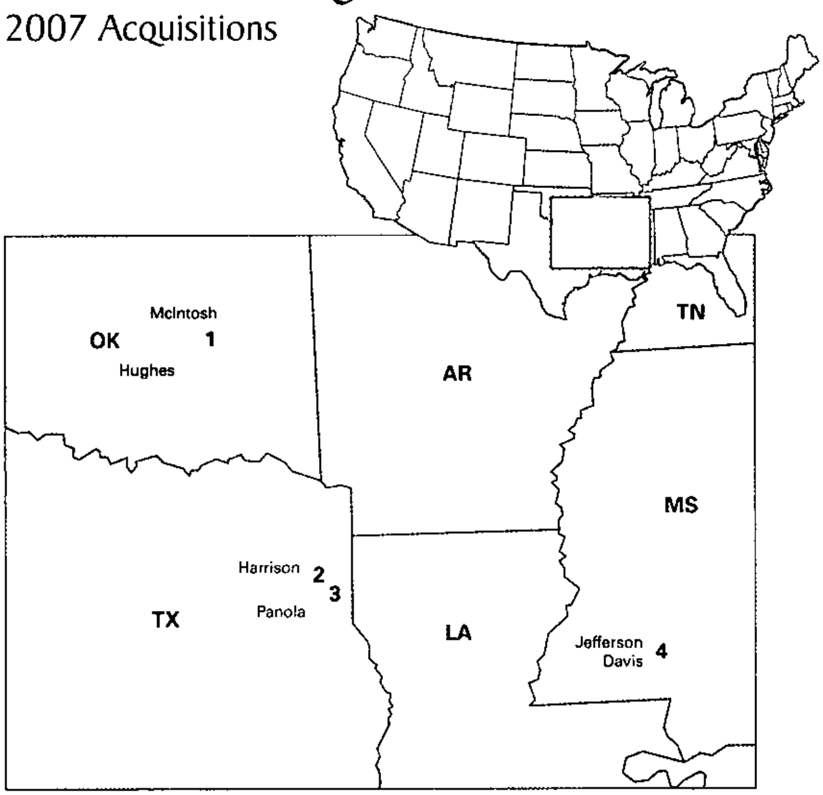
Much of PVR's profitability depends on the relationship between the price it receives for the natural gas liquids (NGLs) it extracts and sells at its processing plants and the price of natural gas it purchases for producers. The difference between these two prices, the fractionation or "frac" spread, can be volatile and difficult to predict. Therefore, PVR employs various commodity price derivatives to protect its margins.

$142 million
of reserve and leasehold acquisitions

74.4 Bcfe
of acquired proved reserves

$1.91 per proved Mcfe for acquisitions

Oil & Gas Segment:
2007 Acquisitions



1. ARKOMA ACQUISITION

Hughes and McIntosh Counties, Oklahoma

$47.9 million; $2.55 per proved Mcfe

Approximately 19 Bcfe of proved reserves, 15 Bcfe of non-proved reserves and 3.1 MMcfed of production

22,700 gross acres – Hartshorne HCBM and Woodford-Caney Shales

2. WOODLAWN FIELD ACQUISITION

Harrison County, Texas

$22.0 million; $1.13 per proved Mcfe

Approximately 20 Bcfe of proved reserves, 10 Bcfe of non-proved reserves and 1.0 MMcfed of production

4,000 gross acres – Cotton Valley and Travis Peak

3. NORTH CARTHAGE FIELD ACQUISITION

Harrison and Panola Counties, Texas

$44.9 million; $2.05 per proved Mcfe

Approximately 22 Bcfe of proved reserves, 104 Bcfe of non-proved reserves and 1.1 MMcfed of production

4,800 gross acres – Cotton Valley

4. GWINVILLE FIELD ACQUISITION

Jefferson Davis County, Mississippi

$10.5 million; $0.94 per proved Mcfe

Approximately 11 Bcfe of proved reserves and 0.6 MMcfed of production

640 gross acres – Selma Chalk

PVA Raises $372 Million of Growth Capital in Public Securities Offerings

In December 2007, we completed our first follow-on public securities offering, raising approximately $372 million of gross proceeds in the form of convertible debt and equity. In addition to broadening access to Penn Virginia by the investment community, the offering allowed us to significantly reduce our bank borrowings such that we had over $350 million of credit availability at year-end 2007. The offering helps position us for 2008, in which we expect to spend up to $475 million on organic oil and gas capital expenditures.

In addition, the new capital helps position us in the event that we make acquisitions, as we did in 2007 with $142 million of reserve and leasehold acquisitions. The new equity capital also lowers our cash interest costs while improving our credit statistics and strengthening our balance sheet.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2007

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 Number)

Three Radnor Corporate Center, Suite 300
100 Matsonford Road
Radnor, Pennsylvania 19087
(Address of principal executive offices)

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

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, $0.01 Par Value	**New York Stock Exchange**

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check One)
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of common stock held by non-affiliates of the registrant was $1,506,589,912 as of June 30, 2007 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including all directors and executive officers of the registrant, but excluding any institutional shareholders. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 28, 2008, 41,632,971 shares of common stock of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

	Part Into Which Incorporated
(1) Proxy Statement for Annual Meeting of Shareholders on May 7, 2008	Part III

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

Table of Contents

Part I

Item 1 *Business*

General

Penn Virginia Corporation (NYSE: PVA) is an independent oil and gas company primarily engaged in the exploration, development and production of natural gas and oil in various onshore U.S. regions including East Texas, the Mid-Continent, Appalachia, Mississippi and the Gulf Coast. We also indirectly own partner interests in Penn Virginia Resource Partners, L.P. (NYSE: PVR), or PVR, a publicly traded limited partnership which is engaged in the coal and natural resource management and natural gas midstream businesses. Our ownership interests in PVR are held principally through our general partner interest and our 82% limited partner interest in Penn Virginia GP Holdings, L.P. (NYSE: PVG), or PVG, a publicly traded limited partnership. PVG owns 100% of the general partner of PVR, which holds a 2% general partner interest in PVR, and an approximately 42% limited partner interest in PVR. See "—Corporate Structure." We consolidate PVG's results into our financial statements. In 2007, we had an approximately 82% interest in PVG's net income. We received cash distributions of $29.6 million, $28.3 million and $21.2 million for the years ended December 31, 2007, 2006 and 2005 on account of our partner interests in PVG and PVR. Our operating income was $192.6 million in 2007, compared to $170.5 million in 2006 and $162.0 million in 2005. Unless the context requires otherwise, references to the "Company," "we," "us" or "our" in this Annual Report on Form 10-K refer to Penn Virginia Corporation and its subsidiaries.

Segments

We are engaged in three primary business segments: (1) oil and gas, (2) coal and natural resource management and (3) natural gas midstream. We operate our oil and gas segment. PVR operates our coal and natural resource management and natural gas midstream segments. In 2007, the oil and gas segment contributed $104.0 million, or 54%, the PVR coal and natural resource management segment contributed $69.0 million, or 36%, and the PVR natural gas midstream segment contributed $48.9 million, or 25%, to operating income. Corporate and other functions resulted in $29.3 million of operating expenses.

Oil and Gas Segment Overview

We have a geographically diverse asset base with core areas of operation in East Texas, the Mid-Continent, Appalachia, Mississippi and the South Louisiana and South Texas Gulf Coast regions of the United States. As of December 31, 2007, we had proved natural gas and oil reserves of approximately 680 Bcfe, of which 87% were natural gas and 59% were proved developed. As of December 31, 2007, 95% of our proved reserves were located in primarily longer-lived, lower-risk basins in East Texas, the Mid-Continent, Appalachia and Mississippi. Wells in these regions are generally characterized by predictable production profiles. Our Gulf Coast properties, representing 5% of proved reserves, are shorter-lived and have higher impact drilling prospects that provide a complementary counterbalance to our longer-lived assets. In 2007, we produced 40.6 Bcfe, a 30% increase compared to 31.3 Bcfe in 2006. As of December 31, 2007, we operated approximately 95% of the net wells in which we held a working interest. In the three years ended December 31, 2007, we drilled 677 gross (507.0 net) wells, of which 95% were successful in producing natural gas in commercial quantities. For a more detailed discussion of our reserves and production, see Item 2, "Properties."

We have grown our reserves and production primarily through development and exploratory drilling, complemented by strategic acquisitions. In 2007, we added 255 Bcfe of proved reserves, 71% of which was added through the drillbit, for a total reserve replacement rate of 628% of production. In 2007, capital expenditures in our oil and gas segment were $520.4 million, of which $333.2 million, or 64%, was related to development drilling and facilities, $141.9 million, or 27%, was related to acquisitions and $45.3 million, or 9%, was related to exploratory activity. During 2007, we acquired properties with 74.4 Bcfe of proved reserves and sold properties with 21.5 Bcfe of proved reserves. For a more detailed discussion of our acquisitions, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions, Dispositions and Investments."

Our operations include both conventional and unconventional developmental drilling opportunities, as well as some exploratory prospects. In the Cotton Valley play in East Texas, we drilled 120 gross wells in 2007 and added a sixth drilling rig in the second half of 2007. We are shifting focus to infill drilling on 20-acre spacing, which may increase proved reserves and production levels. In Appalachia, we drilled 41 gross wells in 2007, including 27 gross horizontal coalbed methane locations. In the Selma Chalk play in Mississippi, we drilled 73 gross wells in 2007, including two successful horizontal wells. We also have unconventional development programs in the Mid-Continent and some higher-impact exploratory prospects in the Gulf Coast.

PVR Coal and Natural Resource Management Segment Overview

The PVR coal and natural resource management segment primarily involves the management and leasing of coal and natural resource properties and the subsequent collection of royalties. PVR also earns revenues from the provision of fee-based coal preparation and loading services, from the sale of standing timber on its properties, from oil and gas royalty interests it owns and from coal transportation, or wheelage, fees.

As of December 31, 2007, PVR owned or controlled approximately 818 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. As of December 31, 2007, approximately 89% of PVR's proven and probable coal reserves were "steam" coal used primarily by electric generation utilities, and the remaining 11% were metallurgical coal used primarily by steel manufacturers. PVR enters into long-term leases with experienced, third-party mine operators, providing them the right to mine its coal reserves in exchange for royalty payments. PVR actively works with its lessees to develop efficient methods to exploit its reserves and to maximize production from its properties. PVR does not operate any mines. In 2007, PVR's lessees produced 32.5 million tons of coal from its properties and paid PVR coal royalties revenues of $94.1 million, for an average royalty per ton of $2.89. Approximately 81% of PVR's coal royalties revenues in 2007 and 84% of PVR's coal royalties revenues in 2006 were derived from coal mined on its properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price. The balance of PVR's coal royalties revenues for the respective periods was derived from coal mined on its properties under leases containing fixed royalty rates that escalate annually. See "—Contracts—PVR Coal and Natural Resource Management Segment" for a description of PVR's coal leases.

PVR Natural Gas Midstream Segment Overview

The PVR natural gas midstream segment is engaged in providing gas processing, gathering and other related natural gas services. PVR owns and operates natural gas midstream assets located in Oklahoma and the panhandle of Texas. These assets include approximately 3,682 miles of natural gas gathering pipelines and three natural gas processing facilities having 160 MMcfd of total capacity. PVR's natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. PVR also owns a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines. PVR acquired its first natural gas midstream assets through the acquisition of Cantera Gas Resources, LLC, or Cantera, in March 2005.

In 2007, system throughput volumes at PVR's gas processing plants and gathering systems, including gathering-only volumes, were 67.8 Bcf, or approximately 186 MMcfd. In 2007, one of PVR's natural gas midstream customers, ConocoPhillips Company, accounted for 25% of PVR's natural gas midstream revenues and 13% of our total consolidated revenues.

Corporate and Other

Corporate and other primarily represents corporate functions.

Business Strategy

We intend to pursue the following business strategies:

- *Continue to grow through the drillbit.* We anticipate spending $474.8 million on development and exploratory drilling and related facilities in 2008. We currently plan to allocate $413.9 million, or 87% of this amount to development drilling activity in our core areas of the East Texas, Mid-Continent, Appalachia and Mississippi regions. We intend to apply the remaining $60.9 million, or 13%, to our exploratory activities in the Gulf Coast, East Texas, Mid-Continent and Appalachian regions. In addition, we are applying horizontal drilling technology in many of our development and exploration plays, which may result in increased reserve additions and higher production rates. Where practical, we collaborate with established industry partners in many of our exploration activities to better manage costs and operational risks.

- *Pursue selective acquisition opportunities in existing basins.* We intend to continue to pursue acquisitions of properties that we believe have primarily development potential and that are consistent with our lower-risk drilling strategies. Our experienced team of management and technical professionals consistently looks for new opportunities to increase reserves and production that complement our existing core properties. For example, in 2007 we acquired, in two transactions, properties with a total of 41.4 Bcfe of management estimated proved reserves located in the Cotton Valley play in East Texas for an aggregate purchase price of $66.9 million; properties with 18.8 Bcfe of management estimated proved reserves in eastern Oklahoma for $47.9 million; and properties with 11.2 Bcfe of management estimated proved reserves for a purchase price of $10.5 million in the Selma Chalk play in Mississippi. Management estimates that these four acquisitions added a total of 74.4 Bcfe of proved reserves and approximately 240 additional drilling locations to our inventory.

- *Manage risk exposure through an active hedging program.* We actively manage our exposure to commodity price fluctuations by hedging the commodity price risk for our expected proved developed production through the use of derivatives, typically costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our cash flow at risk, available hedge prices and our operating strategy. As of December 31, 2007, we had hedged approximately 35% and 19% of proved developed production for 2008 and the first through third quarters of 2009.

- *Assist PVR in growing its sources of cash flow.* PVR's management continues to focus on acquisitions and investments that increase and diversify its sources of long-term cash flow. During 2007, PVR acquired 60 million tons of coal reserves in two acquisitions for an aggregate purchase price of approximately $52 million. In addition, in 2007, PVR acquired approximately 62,000 acres of forestland in West Virginia for a purchase price of approximately $93 million and royalty interests in certain oil and gas leases relating to properties located in Kentucky and Virginia for a purchase price of approximately $31 million. The gain on the sale of royalty interests to PVR was eliminated in the consolidation of our financial statements. During 2007, PVR also expended $38.7 million on expansion projects to allow it to capitalize on opportunities to add new supplies of natural gas. The expansion projects included two natural gas processing facilities with a combined 140 MMcfd of inlet gas capacity, which are expected to commence operations in 2008. For a more detailed discussion of PVR's acquisitions, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions, Dispositions and Investments."

- *Utilize the advantages of our relationship with PVR.* During 2006, PVR began marketing our natural gas production in Louisiana, Oklahoma and Texas, replacing a third party marketing company and allowing us to realize higher prices for our oil and natural gas sold in that region. In 2007, PVR announced plans to construct a new 80 MMcfd gas processing plant in the Bethany Field in east Texas and entered into a gas gathering and processing agreement with us. The new east Texas plant will provide fee-based gas processing services to our oil and gas business, as well as other producers. In addition, as discussed above, we sold approximately $31 million of oil and gas royalty interests to PVR, allowing us to profitably dispose of non-core assets. The gain on the sale of royalty interests to PVR was eliminated in the consolidation of our financial statements. We will continue to look for ways to take advantage of our relationship with PVR in mutually beneficial ways.

Contracts

Oil and Gas Segment

Transportation. The majority of our natural gas production is transported to market on three major pipeline or transmission systems. NiSource Inc., Crosstex Energy Services L.P. and Duke Energy Corporation transported approximately 16%, 19% and 21% of our 2007 natural gas production. The remainder of our natural gas production was transported by several pipeline companies in Louisiana, Texas and West Virginia. In almost all cases, our natural gas is sold at interconnects with transmission pipelines.

We have entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to 15 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

Marketing. We generally sell our natural gas using spot market and short-term fixed price physical contracts. For the year ended December 31, 2007, two of our oil and gas customers, Crosstex Gulfcoast Marketing and Duke Energy Corporation, accounted for approximately 17% and 18% of our natural gas and oil and condensate revenues and 6% and 6% of our total consolidated revenues.

PVR Coal and Natural Resource Management Segment

PVR earns most of its coal royalties revenues under long-term leases that generally require its lessees to make royalty payments to it based on the higher of a percentage of the gross sales price or a fixed price per ton of coal they sell. The balance of PVR's coal royalties revenues are earned under long-term leases that require the lessees to make royalty payments to PVR based on fixed royalty rates which escalate annually. A typical lease either expires upon exhaustion of the leased reserves or has a five to ten-year base term, with the lessee having an option to extend the lease for at least five years after the expiration of the base term. Substantially all of PVR's leases require the lessee to pay minimum rental payments to PVR in monthly or annual installments, even if no mining activities are ongoing. These minimum rentals are recoupable, usually over a period from one to three years from the time of payment, against the production royalties owed to PVR once coal production commences.

Substantially all of PVR's leases impose obligations on the lessees to diligently mine the leased coal using modern mining techniques, indemnify PVR for any damages it incurs in connection with the lessee's mining operations, including any damages PVR may incur due to the lessee's failure to fulfill reclamation or other environmental obligations, conduct mining operations in compliance with all applicable laws, obtain its written consent prior to assigning the lease and maintain commercially reasonable amounts of general liability and other insurance. Substantially all of the leases grant PVR the right to review all lessee mining plans and maps, enter the leased premises to examine mine workings and conduct audits of lessees' compliance with lease terms. In the event of a default by a lessee, substantially all of the leases give PVR the right to terminate the lease and take possession of the leased premises.

In addition, PVR earns revenues under coal services contracts, timber contracts and oil and gas leases. PVR's coal services contracts generally provide that the users of PVR's coal services pay PVR a fixed fee per ton of coal processed at its facilities. All of PVR's coal services contracts are with lessees of PVR's coal reserves and these contracts generally have terms that run concurrently with the related coal lease. PVR's timber contracts generally provide that the timber companies pay us a fixed price per thousand board feet of timber harvested from our property. PVR receives royalties under its oil and gas leases based on a percentage of the revenues the producers receive for the oil and gas they sell.

PVR Natural Gas Midstream Segment

PVR's natural gas midstream business generates revenues primarily from gas purchase and processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. During the year ended December 31, 2007, PVR's natural gas midstream business generated a majority of its gross margin from two types of contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs: (i) percentage-of-proceeds and (ii) keep-whole arrangements. As of December 31, 2007, approximately 37% of PVR's system throughput volumes were processed under gas purchase/keep-whole contracts, 34% were processed under percentage-of-proceeds contracts, and 29% were processed under fee-based gathering contracts. A majority of the gas purchase/keep-whole and percentage-of-proceeds contracts include fee-based components such as gathering and compression charges. There is also a processing fee floor included in many of the gas purchase/keep-whole contracts that ensures a minimum processing margin should the actual margins fall below the floor.

Gas Purchase/Keep-Whole Arrangements. Under these arrangements, PVR generally purchases natural gas at the wellhead at either (i) a percentage discount to a specified index price, (ii) a specified index price less a fixed amount or (iii) a combination of (i) and (ii). PVR then gathers the natural gas to one of its plants where it is processed to extract the entrained NGLs, which are then sold to third parties at market prices. PVR resells the remaining natural gas to third parties at an index price which typically corresponds to the specified purchase index. Because the extraction of the NGLs from the natural gas during processing reduces the BTU content of the natural gas, PVR retains a reduced volume of gas to sell after processing. Accordingly, under these arrangements, PVR's revenues and gross margins increase as the price of NGLs increases relative to the price of natural gas, and its revenues and gross margins decrease as the price of natural gas increases relative to the price of NGLs. PVR has generally been able to mitigate its exposure in the latter case by requiring the payment under many of its gas purchase/keep-whole arrangements of minimum processing charges which ensure that PVR receives a minimum amount of processing revenues. The gross margins that PVR realizes under the arrangements described in clauses (i) and (iii) above also decrease in periods of low natural gas prices because these gross margins are based on a percentage of the index price.

Percentage-of-Proceeds Arrangements. Under percentage-of-proceeds arrangements, PVR generally gathers and processes natural gas on behalf of producers, sells the resulting residue gas and NGL volumes at market prices and remits to producers an agreed-upon percentage of the proceeds of those sales based on either an index price or the price actually received for the gas and NGLs. Under these types of arrangements, PVR's revenues and gross margins increase as natural gas prices and NGL prices increase, and its revenues and gross margins decrease as natural gas prices and NGL prices decrease.

Fee-Based Arrangements. Under fee-based arrangements, PVR receives fees for gathering, compressing and/or processing natural gas. The revenues PVR earns from these arrangements are directly dependent on the volume of natural gas that flows through its systems and are independent of commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, PVR's revenues from these arrangements would be reduced due to the related reduction in drilling and development of new supply.

In many cases, PVR provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of PVR's contracts vary based on gas quality conditions, the competitive environment at the time the contracts were signed and customer requirements. The contract mix and, accordingly, exposure to natural gas and NGL prices, may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

PVR is also engaged in natural gas marketing by aggregating third-party volumes and selling those volumes into interstate and intrastate pipeline systems such as Enogex and ONEOK and at market hubs accessed by various interstate pipelines. Connect Energy Services, LLC, a wholly-owned subsidiary of PVR, earned fees for marketing a portion of Penn Virginia Oil & Gas, L.P.'s natural gas production during 2007 and 2006. Penn Virginia Oil & Gas, L.P. is a wholly-owned subsidiary of us. The marketing agreement was effective September 1, 2006. Revenues from this business do not generate qualifying income for a publicly traded limited partnership, but PVR does not expect it to have an impact on its tax status, as it does not represent a significant percentage of PVR's operating income. For the years ended December 31, 2007 and 2006, natural gas marketing activities generated $4.6 million and $2.2 million in net revenues.

Commodity Derivative Contracts

Our oil and gas segment and the PVR natural gas midstream segment utilize costless collar, three-way option and swap derivative contracts to hedge against the variability in cash flows associated with forecasted oil and gas revenues and natural gas midstream revenues and cost of midstream gas purchased. The PVR natural gas midstream segment also utilizes swap derivative contracts to hedge against the variability in its "frac spread." PVR's frac spread is the spread between the purchase price for the natural gas PVR purchases from producers and the sale price for the NGLs that PVR sells after processing. PVR hedges against the variability in its frac spread by entering into swap derivative contracts to sell NGLs forward at a predetermined swap price and to purchase an equivalent volume of natural gas forward on an MMbtu basis. While the use of derivative instruments limits the risk of adverse price movements, their use also may limit future revenues or cost savings from favorable price movements.

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

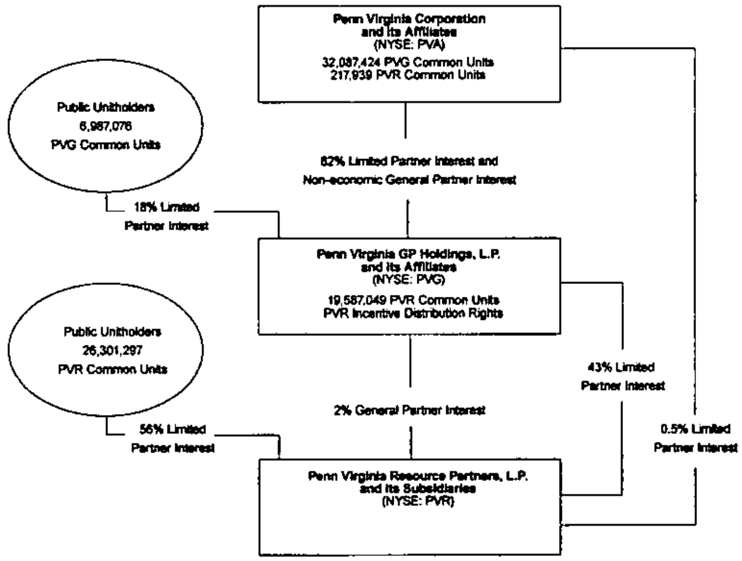
A three-way option contract consists of a collar contract as described above plus a put option contract sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put option price. By combining the collar contract with the additional put option, we are entitled to a net payment equal to the difference between the floor price of the collar contract and the additional put option price if the settlement price is equal to or less than the additional put option price. If the settlement price is greater than the additional put option price, the result is the same as it would have been with a collar contract only. This strategy enables us to increase the floor and the ceiling prices of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract.

See Note 11 in the Notes to Consolidated Financial Statements for a further description of our and PVR's derivatives programs.

Corporate Structure

As of December 31, 2007, we owned the general partner of PVG and an approximately 82% limited partner interest in PVG. PVG owns the general partner of PVR, which holds a 2% general partner interest in PVR and all the incentive distribution rights, and an approximately 42% limited partner interest in PVR. We directly owned an additional 0.5% limited partner interest in PVR as of December 31, 2007. The following diagram depicts our ownership of PVG and PVR as of December 31, 2007:



Because we control the general partner of PVG, the financial results of PVG are included in our consolidated financial statements. Because PVG controls the general partner of PVR, the financial results of PVR are included in PVG's consolidated financial statements. However, PVG and PVR function with capital structures that are independent of each other and us, with each having publicly traded common units and PVR having its own debt instruments. PVG does not currently have any debt instruments. While we report consolidated financial results of PVR's coal and natural resources management and natural gas midstream businesses, the only cash we receive from those businesses is in the form of cash distributions we receive from PVG and PVR in respect of our partner interests in each of them.

Partnership Distributions

PVG Cash Distributions

PVG paid cash distributions of $0.91 per common unit during the year ended December 31, 2007. In the first quarter of 2008, PVG paid a quarterly distribution of $0.32 ($1.28 on an annualized basis) per common unit with respect to the fourth quarter of 2007. For the remainder of 2008, PVG expects to pay quarterly distributions of at least $0.32 ($1.28 on an annualized basis) per common unit.

PVR Cash Distributions

PVR paid cash distributions of $1.66 per common and Class B unit during the year ended December 31, 2007. In the first quarter of 2008, PVR paid a quarterly distribution of $0.44 ($1.76 on an annualized basis) per common unit with respect to the fourth quarter of 2007. For the remainder of 2008, PVR expects to pay quarterly distributions of at least $0.44 ($1.76 on an annualized basis) per common unit.

PVR Incentive Distribution Rights

A wholly owned subsidiary of PVG is the general partner of PVR and, as such, holds certain incentive distribution rights which represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after PVR has paid minimum quarterly distributions and certain target distribution levels have been achieved. The minimum quarterly distribution is $0.25 per unit ($1.00 per unit on an annualized basis). PVR's general partner currently holds 100% of the incentive distribution rights, but may transfer these rights separately from its general partner interest to an affiliate (other than an individual) or to another entity as part of the merger or consolidation of the general partner with or into such entity or the transfer of all or substantially all of the general partner's assets to another entity without the prior approval of PVR's unitholders if the transferee agrees to be bound by the provisions of PVR's partnership agreement. Prior to September 30, 2011, other transfers of incentive distribution rights will require the affirmative vote of holders of a majority of PVR's outstanding common units. On or after September 30, 2011, the incentive distribution rights will be freely transferable.

PVG's ownership of PVR's incentive distribution rights entitles it to receive the following percentages of cash distributed by PVR as it reaches the following target cash distribution levels:

- 13% of all incremental cash distributed in a quarter after $0.275 has been distributed in respect of each common unit of PVR for that quarter;
- 23% of all incremental cash distributed after $0.325 has been distributed in respect of each common unit of PVR for that quarter; and
- the maximum sharing level of 48% of all incremental cash distributed after $0.375 has been distributed in respect of each common unit of PVR for that quarter.

Since 2001, PVR has increased its quarterly cash distribution 13 times from $0.25 per unit ($1.00 on an annualized basis) to $0.44 per unit ($1.76 on an annualized basis), which is its most recently declared distribution. These increased cash distributions by PVR have placed PVG at the third and maximum target cash distribution level as described above. As a consequence, any increase in cash distributions from PVR will allow PVG to share at the 48% level and the cash distributions PVG receives from PVR with respect to its indirect ownership of the incentive distribution rights will increase more rapidly than those with respect to its ownership of the general partner and limited partner interests. Because PVG is at the maximum target cash distribution level on the incentive distribution rights, future growth in distributions it receives from PVR will not result from an increase in the target cash distribution level associated with the incentive distribution rights.

Cash Distributions Received

Prior to PVG's initial public offering, or the PVG IPO, in December 2006, we indirectly owned common units representing an approximately 37% limited partner interest in PVR, as well the sole 2% general partner interest and all of the incentive distribution rights in PVR. In conjunction with the PVG IPO, we contributed our general partner interest, including our incentive distribution rights, and most of our limited partner interest in PVR to PVG in exchange for the general partner interest and a limited partner interest in PVG. PVG also purchased additional common units and Class B units of PVR with the proceeds of the PVG IPO.

We are currently entitled to receive quarterly cash distributions from PVG and PVR on our limited partner interests in PVG and PVR. We have historically received increasing distributions from our partner interests in PVG and PVR. As a result of our partner interests in PVG and PVR, we received total distributions from PVG and PVR in 2007, 2006 and 2005 as shown in the following table:

	Year Ended December 31,		
	2007	**2006**	**2005**
		(in thousands)	
Penn Virginia GP Holdings, L.P.	$29,200	$ —	$ —
Penn Virginia Resource Partners, L.P.	398	28,326	21,212
Total	$29,598	$28,326	$21,212

Based on PVG's and PVR's current annualized distribution rates of $1.28 and $1.76 per unit, we would receive aggregate annualized distributions of $41.5 million in respect of our partner interests.

We received total distributions from PVR of $28.3 million and $21.2 million in 2006 and 2005, allocated among our limited partner interest, general partner interest and incentive distribution rights in PVR as shown in the following table:

	Year Ended December 31,	
	2006	2005
	(in thousands)	
Limited partner units	$22,799	$19,281
General partner interest (2%)	1,254	1,021
Incentive distribution rights	4,273	910
Total	$28,326	$21,212

Competition

Oil and Gas Segment

The oil and natural gas industry is very competitive, and we compete with a substantial number of other companies that are large, well-established and have greater financial and operational resources than we do, which may adversely affect our ability to compete or grow our business. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations, electricity generation and the marketing of refined products. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Our competitive position depends on our geological, geophysical and engineering expertise, our financial resources, our ability to develop properties and our ability to select, acquire and develop proved reserves. We compete with other oil and natural gas companies to secure drilling rigs and other equipment necessary for the drilling and completion of wells and recruiting and retaining qualified personnel, including geologists, geo-physicists, engineers and other specialists. Such equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. We also compete with major and independent oil and gas companies in the marketing and sale of oil and natural gas, and the oil and natural gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers.

PVR Coal and Natural Resource Management Segment

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

PVR Natural Gas Midstream Segment

The ability to offer natural gas producers competitive gathering and processing arrangements and subsequent reliable service is fundamental to obtaining and keeping gas supplies for PVR's gathering systems. The primary concerns of the producer are:

- the pressure maintained on the system at the point of receipt;
- the relative volumes of gas consumed as fuel and lost;
- the gathering/processing fees charged;
- the timeliness of well connects;
- the customer service orientation of the gatherer/processor; and
- the reliability of the field services provided.

PVR experiences competition in all of its natural gas midstream markets. PVR's competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas. Many of PVR's competitors have greater financial resources and access to larger natural gas supplies than PVR does.

Government Regulation and Environmental Matters

The operations of our oil and gas business and PVR's coal and natural resource management business and natural gas midstream business are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted.

Oil and Gas Segment

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

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

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

The Energy Policy Act of 2005 amended the NGA and the NGPA and gave the FERC the authority to assess civil penalties of up to $1 million per day per violation for violations of rules, regulations, and orders issued under these acts. In addition, the FERC has issued regulations that make it unlawful for any entity in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of the FERC to use any manipulative or deceptive device or contrivance.

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

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

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

PVR Coal and Natural Resource Management Segment

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

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

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

Air Emissions. The Clean Air Act, or the CAA, and corresponding state and local laws and regulations affect all aspects of PVR's business, both directly and indirectly. The CAA directly impacts PVR's lessees' coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. There have been a series of recent federal rulemakings that are focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and additional measures required under U.S. Environmental Protection Agency, or the EPA, laws and regulations will make it more costly to build and operate coal-fired power plants and, depending on the requirements of individual state implementation plans, could make coal a less attractive fuel alternative in the planning and building of power plants in the future. Any reduction in coal's share of power generating capacity could negatively impact PVR's lessees' ability to sell coal, which could have a material effect on PVR's coal royalties revenues.

The EPA's Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility's sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or "scrubbers," or by reducing electricity generating levels.

The EPA has promulgated rules, referred to as the "NOx SIP Call," that require coal-fired power plants and other large stationary sources in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule, or CAIR, which will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010. CAIR requires these states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered "cap-and-trade" program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state. The stringency of the caps under CAIR may require many coal-fired sources to install additional pollution control equipment, such as wet scrubbers, to comply. This increased sulfur emission removal capability required by CAIR could result in decreased demand for lower sulfur coal, which may potentially drive down prices for lower sulfur coal.

In March 2005, the EPA finalized the Clean Air Mercury Rule, or CAMR, which was to establish a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. It was the subject of extensive controversy and litigation and, in February 2008, the U.S. Circuit Court of Appeals for the District of Columbia vacated CAMR. EPA has not yet indicated if it will appeal the decision or how it will proceed with the regulation of mercury emissions. Various states have promulgated or are considering more stringent emission limits on mercury emissions from coal-fired electric generating units.

The EPA has adopted new, more stringent national air quality standards for ozone and fine particulate matter. As a result, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. In March 2007, the EPA published final rules addressing how states would implement plans to bring regions designated as non-attainment for fine particulate matter into compliance with the new air quality standard. Under the EPA's final rule, states have until April 2008 to submit their implementation plans to the EPA for approval. Because coal mining operations and coal-fired electric generating facilities emit particulate matter, PVR's lessees' mining operations and their customers could be affected when the new standards are implemented by the applicable states.

Likewise, the EPA's regional haze program to improve visibility in national parks and wilderness areas required affected states to develop implementation plans by December 2007 that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. This program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas. In addition, this program may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide and particulate matter.

The U.S. Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the new source review provisions of the CAA. The EPA has alleged that certain modifications have been made to these facilities without first obtaining permits required under the new source review program. Several of these lawsuits have settled, but others remain pending. On April 2, 2007, the United States Supreme Court ruled in one such case, *Environmental Defense v. Duke Energy Corp.* The Court held that EPA is not required to use an "hourly rate test" in determining whether a modification to a coal burning utility requires a permit under the new source review program, thus allowing the EPA to apply a test based on average annual emissions. The use of an annual emissions test could subject more coal-fired utility modification projects to the permitting requirements of the CAA New Source Review Program, such as those that allow plants to run for more hours in a given year. However, Duke is expected to continue to contest remaining issues in the case, and so litigation in this and other pending cases will likely continue. Depending on the ultimate resolution of these cases, demand for PVR's coal could be affected, which could have an adverse effect on PVR's coal royalties revenues.

Carbon Dioxide Emissions. The Kyoto Protocol to the United Nations Framework Convention on Climate Change calls for developed nations to reduce their emissions of greenhouse gases to 5% below 1990 levels by 2012. Carbon dioxide, which is a major byproduct of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005 for those nations that ratified the treaty. In 2002, the United States withdrew its support for the Kyoto Protocol, and the United States is not participating in this treaty. Since the Kyoto Protocol became effective, there has been increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. In addition, on April 2, 2007 the United States Supreme Court held in *Massachusetts v. EPA* that unless the EPA affirmatively concludes that greenhouse gases are not causing climate change, the EPA must regulate greenhouse gas emissions from new automobiles under the CAA. The Supreme Court remanded the matter to the EPA for further consideration. This litigation did not directly concern the EPA's authority to regulate greenhouse gas emissions from stationary sources, such as coal mining operations or coal-fired power plants. However, the Court's decision is likely to influence another lawsuit currently pending in the U.S. Court of Appeals for the District of Columbia Circuit, involving a challenge to the EPA's decision not to regulate carbon dioxide from power plants and other stationary sources under a CAA new source performance standard rule, which specifies emissions limits for new facilities. The court remanded that question to EPA for further consideration in light of the ruling in *Massachusetts v. EPA*, but any decision in this case or any regulatory action by the EPA limiting greenhouse gas emissions from power plants could impact the demand for PVR's coal, which could have an adverse effect on PVR's coal royalties revenues.

The permitting of a number of proposed new coal-fired power plants has also recently been contested by environmental organizations for concerns related to greenhouse gas emissions from new plants. In October 2007, state regulators in Kansas became the first to deny an air emissions construction permit for a new coal-fired power plant based on the plant's projected emissions of carbon dioxide. State regulatory authorities in Florida and North Carolina have also rejected the construction of new coal-fired power plants based on the uncertainty surrounding the potential costs associated with greenhouse gas emissions from these plants under future laws limiting the emission of carbon dioxide. In addition, permits for several new coal-fired power plants without limits imposed on their greenhouse gas emissions have been appealed by environmental organizations to the U.S. EPA's Environmental Appeals Board.

Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. For example, in December 2005, seven northeastern states agreed to implement a regional cap-and-trade program, referred to as the Regional Greenhouse Gas Initiative, or the RGGI, to stabilize carbon dioxide emissions from regional power plants beginning in 2009. This initiative aims to reduce emissions of carbon dioxide to levels roughly corresponding to average annual emissions between 2000 and 2004. Massachusetts and Rhode Island agreed to join this group in February 2007 and Maryland agreed to join the group in April 2007. The members of RGGI agreed to seek to establish in statute and/or regulation a carbon dioxide trading program and have each state's component of the regional program effective no later than December 31, 2008. Following the RGGI model, seven Western states have also formed a regional greenhouse gas reduction initiative known as the Western Regional Climate Action Initiative, which calls for an overall reduction of regional greenhouse gas emissions from major industrial and commercial sources in participating states through trading of emissions credits beginning in 2012. Also, in 2006, the governor of California signed Assembly Bill 32 into law, requiring the California Air Resources Board to develop regulations and market mechanisms to reduce California's greenhouse gas emissions by 25% by 2020 with mandatory caps beginning in 2012 for significant sources.

Several different pieces of legislation were introduced in Congress in 2007 to reduce greenhouse gas emissions in the United States. Such or similar federal legislation could be taken in 2008 or later years. It is possible that future federal and state initiatives to control and put a price on carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact PVR's lessees' coal sales, and thereby have an adverse effect on PVR's coal royalties revenues.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977, or SMCRA, and similar state statutes establish minimum national operational, reclamation and closure standards for all aspects of surface mining, as well as most aspects of deep mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. SMCRA also imposes on mine operators the responsibility of restoring the land to its original state and compensating the landowner for types of damages occurring as a result of mining operations, and require mine operators to post performance bonds to ensure compliance with any reclamation obligations on the theory that PVR "owned" or "controlled" the mine operator in such a way for liability to attach. Regulatory authorities may attempt to assign the liabilities of PVR's coal lessees to another entity such as PVR if any of its lessees are not financially capable of fulfilling those obligations. To our knowledge, no such claims have been asserted against PVR to date. In conjunction with mining the property, PVR's coal lessees are contractually obligated under the terms of their leases to comply with all state and local laws, including SMCRA, with obligations including the reclamation and restoration of the mined areas by grading, shaping and reseeding the soil. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan. Additionally, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is 31.5 cents per ton on surface-mined coal and 13.5 cents per ton on underground-mined coal. This tax was set to expire on June 30, 2006, but the program was extended until September 30, 2021.

Federal and state laws require bonds to secure our lessees' obligations to reclaim lands used for mining and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for mining companies to secure new surety bonds without the posting of partial collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable. It is possible that surety bonds issuers may refuse to renew bonds or may demand additional collateral upon those renewals. Any failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on PVR's lessees' ability to produce coal, which could affect PVR's coal royalties revenues.

Hazardous Materials and Wastes. The Federal Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, or the Superfund law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

Some products used by coal companies in operations generate waste containing hazardous substances. PVR could become liable under federal and state Superfund and waste management statutes if its lessees are unable to pay environmental cleanup costs. CERCLA authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek recovery from the responsible classes of persons of the costs they incurred in connection with such response. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment. The Resource Conservation and Recovery Act, or RCRA, and corresponding state laws and regulations exclude many mining wastes from the regulatory definition of hazardous wastes. Currently, the management and disposal of coal combustion by-products are also not regulated at the federal level and not uniformly at the state level. If rules are adopted to regulate the management and disposal of these by-products, they could add additional costs to the use of coal as a fuel and may encourage power plant operators to switch to a different fuel.

Clean Water Act. PVR's coal lessees' operations are regulated under the Clean Water Act, or the CWA, with respect to discharges of pollutants, including dredged or fill material into waters of the United States. Individual or general permits under Section 404 of the CWA are required to conduct dredge or fill activities in jurisdictional waters of the United States. Surface coal mining operators obtain these permits to authorize such activities as the creation of slurry ponds, stream impoundments and valley fills. Uncertainty over what legally constitutes a navigable water of the United States within the CWA's regulatory scope may adversely impact the ability of PVR's coal lessees to secure the necessary permits for their mining activities. Some surface mining activities require a CWA Section 404 "dredge and fill" permit under the CWA for valley fills and the associated sediment control ponds. On June 5, 2007, in response to the U.S. Supreme Court's divided opinion in *Rapanos v. United States*, the EPA and the U.S. Army Corps of Engineers, or the Corps, issued joint guidance to EPA regions and Corps districts interpreting the geographic extent of regulatory jurisdiction under Section 404 of the CWA. Specifically, the guidance places jurisdictional water bodies into two groups: waters where the agencies will assert regulatory jurisdiction "categorically" and waters where the agencies will assert jurisdiction on a case-by-case basis following a "significant nexus analysis." It remains to be seen how this guidance will affect the permitting process for obtaining additional permits for valley fills and sediment ponds although it is likely to add uncertainty and delays in the issuance of new permits. Some valley fill surface mining activities have the potential to impact headwater streams that are not relatively permanent, which could therefore trigger a detailed "significant nexus analysis" to determine whether a Section 404 permit would be required. Such analyses could require the extensive collection of additional field data and could lead to delays in the issuance of CWA Section 404 permits for valley fill surface mining operations.

Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created additional uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. The Corps is authorized by Section 404 of the CWA to issue "nationwide" permits for specific categories of dredging and filling activities that are similar in nature and that are determined to have minimal adverse environmental effects. Nationwide Permit 21 authorizes the disposal of dredged or fill material from surface coal mining activities into the waters of the United States. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the Corps from issuing further permits pursuant to Nationwide Permit 21. While the decision was vacated by the Fourth Circuit Court of Appeals in November 2005, it has been remanded to the District Court for the Southern District of West Virginia for further proceedings. Moreover, a similar lawsuit has been filed in the U.S. District Court for the Eastern District of Kentucky that seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the Corps.

In the event similar lawsuits prove to be successful in adjoining jurisdictions, PVR's lessees may be required to apply for individual discharge permits pursuant to Section 404 of the CWA in areas where they would have otherwise utilized Nationwide Permit 21. Such a change could result in delays in PVR's lessees obtaining the required mining permits to conduct their operations, which could in turn have an adverse effect on PVR's coal royalties revenues.

Individual CWA Section 404 permits for valley fills associated with surface mining activities are also subject to certain legal challenges and uncertainty. On September 22, 2005, in the case *Ohio Valley Environmental Coalition ("OVEC") v. United States Army Corps of Engineers*, environmental group plaintiffs filed suit in the U.S. District Court for the Southern District of West Virginia challenging the Corps' decision to issue individual CWA Section 404 permits for certain mining projects. Alex Energy, Inc., or Alex Energy, a lessee of PVR that operates the Republic No. 2 Mine in Kanawha County, West Virginia, intervened as a defendant in this litigation when the plaintiffs' amended their complaint to add the December 22, 2005 individual CWA Section 404 permit for the Republic No. 2 Mine, or the Republic No. 2 Permit. On March 23, 2007, the district court rescinded several challenged CWA Section 404 permits, including the Republic No. 2 Permit, and remanded the permit applications to the Corps for further proceedings. In addition, the district court enjoined the permit holders, including Alex Energy, from all activities authorized under the rescinded permits. As part of the *OVEC* litigation, the environmental groups have also challenged the CWA Section 404 permit issued to Alex Energy for the Republic No. 1 Mine, also located in Kanawha County, West Virginia.

On April 10, 2007, Alex Energy filed a notice of appeal of the March 23, 2007 ruling to the United States Court of Appeals. On May 18, 2007, the Corps and the West Virginia Mining Association also filed notices of appeal as defendants. On April 20, 2007, the district court granted a limited stay of its previous order to allow certain valley fills already partially constructed where the receiving waters had been filled. This limited stay specifically allows Alex Energy to continue to use Valley Fill No. 1 with respect to the Republic No. 2 Mine; however, construction of the other valley fills and sediment ponds remain enjoined pending appeal. In December 2007, plaintiff environmental groups brought a similar suit against the issuance of a CWA Section 404 permit for a surface coal mine in the U.S. District Court for the Eastern District of Kentucky, alleging identical violations. The Corps has voluntarily suspended its consideration of the permit application in that case for agency re-evaluation. While the final outcome of these cases remains uncertain, if the *OVEC* lawsuit ultimately limits or prohibits the mining methods or operations of PVR's lessees, it could have an adverse effect on PVR's coal royalties revenues. In addition, it is possible that similar litigation affecting recently issued, pending or future individual or general CWA Section 404 permits relevant to the mining and related operations of PVR's lessees could adversely impact PVR's coal royalties revenues.

Total Maximum Daily Load, or TMDL, regulations under the CWA establish a process to calculate the maximum amount of a pollutant that a water body can receive and still meet state water quality standards and to allocate pollutant loads among the point- and non-point pollutant sources discharging into that water body. This process applies to those waters that states have designated as impaired (not meeting present water quality standards). Industrial dischargers, including coal mines, discharging to such waters will be required to meet new TMDL load allocations for these stream segments. The adoption of new TMDL-related allocations for streams to which PVR's lessees' coal mining operations discharge could require more costly water treatment and could adversely affect PVR's lessees' coal production.

The CWA also requires states to develop anti-degradation policies to ensure non-impaired water bodies in the state do not fall below applicable water quality standards. These and other regulatory developments may restrict PVR's lessees' ability to develop new mines or could require PVR's lessees to modify existing operations, which could have an adverse effect on PVR's coal business.

The Safe Drinking Water Act, or the SDWA, and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal slurries, fly ash and flue gas scrubber sludge, and by requiring permits to conduct such underground injection activities. In addition to establishing the underground injection control program, the SDWA also imposes regulatory requirements on owners and operators of "public water systems." This regulatory program could impact PVR's lessees' reclamation operations where subsidence or other mining-related problems require the provision of drinking water to affected adjacent homeowners.

Endangered Species Act. The Endangered Species Act and counterpart state legislation protect species threatened with possible extinction. Protection of threatened and endangered species may have the effect of prohibiting or delaying PVR's lessees from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species or their habitats. A number of species indigenous to areas where PVR's properties are located are protected under the Endangered Species Act. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect PVR's lessees' ability to mine coal from PVR's properties in accordance with current mining plans.

Mine Health and Safety Laws. The operations of PVR's coal lessees are subject to stringent health and safety standards that have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 resulted in increased operating costs and reduced productivity. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive health and safety standards on all mining operations. In addition, as part of the Mine Health and Safety Acts of 1969 and 1977, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung or pneumoconiosis and to some beneficiaries of miners who have died from this disease.

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

On June 15, 2006, the President signed the "Miner Act," which was new mining safety legislation that mandates improvements in mine safety practices, increases civil and criminal penalties for non-compliance, requires the creation of additional mine rescue teams and expands the scope of federal oversight, inspection and enforcement activities. Pursuant to the Miner Act, the Mine Safety Health Administration, or MSHA, has promulgated new emergency rules on mine safety and revised MSHA's civil penalty assessment regulations, which resulted in an across-the-board increase in penalties from the existing regulations. These requirements may add significant costs to PVR's lessees' operations, particularly for underground mines, and could affect the financial performance of PVR's lessees' operations.

Implementing and complying with these new laws and regulations could adversely affect PVR's lessees' coal production and could therefore have an adverse effect on PVR's coal royalties revenues.

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

Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws. Regulations also provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations which have outstanding environmental violations. Although, like other coal companies, PVR's lessees' have been cited for violations in the ordinary course of business, to our knowledge, none of them have had one of their permits suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

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

OSHA. PVR's lessees and PVR's own business are subject to OSHA. See "—Oil and Gas Segment—OSHA."

PVR Natural Gas Midstream Segment

General Regulation. PVR's natural gas gathering facilities generally are exempt from the FERC's jurisdiction under the NGA, but FERC regulation nevertheless could significantly affect PVR's gathering business and the market for its services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which PVR's gathering pipelines deliver. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

For example, the FERC will assert jurisdiction over an affiliated gatherer that acts to benefit its pipeline affiliate in a manner that is contrary to the FERC's policies concerning jurisdictional services adopted pursuant to the NGA. In addition, natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that the FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. PVR's gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. PVR's gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on PVR's natural gas midstream operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

In Texas, PVR's gathering facilities are subject to regulation by the Texas Railroad Commission, which has the authority to ensure that rates, terms and conditions of gas utilities, including certain gathering facilities, are just and reasonable and not discriminatory. PVR's operations in Oklahoma are regulated by the Oklahoma Corporation Commission, which prohibits PVR from charging any unduly discriminatory fees for its gathering services. We cannot predict whether PVR's gathering rates will be found to be unjust, unreasonable or unduly discriminatory.

PVR is subject to ratable take and common purchaser statutes in Texas and Oklahoma. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting PVR's right as an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and Texas and Oklahoma have adopted complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering rates and access. We cannot assure you that federal and state authorities will retain their current regulatory policies in the future.

Texas and Oklahoma administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, or the NGPSA, which requires certain pipelines to comply with safety standards in constructing and operating the pipelines, and subjects pipelines to regular inspections. In response to recent pipeline accidents, Congress and the U.S. Department of Transportation have instituted heightened pipeline safety requirements. Certain of PVR's gathering facilities are exempt from these federal pipeline safety requirements under the rural gathering exemption. We cannot assure you that the rural gathering exemption will be retained in its current form in the future.

Failure to comply with applicable regulations under the NGA, the NGPSA and certain state laws can result in the imposition of administrative, civil and criminal remedies.

Air Emissions. PVR's natural gas midstream operations are subject to the CAA and comparable state laws and regulations. See "—PVR Coal and Natural Resource Management Segment—Air Emissions." These laws and regulations govern emissions of pollutants into the air resulting from the activities of PVR's processing plants and compressor stations and also impose procedural requirements on how PVR conducts its natural gas midstream operations. Such laws and regulations may include requirements that PVR obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, strictly comply with the emissions and operational limitations of air emissions permits PVR is required to obtain or utilize specific equipment or technologies to control emissions. PVR's failure to comply with these requirements could subject it to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. PVR will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Hazardous Materials and Wastes. PVR's natural gas midstream operations could incur liability under CERCLA and comparable state laws resulting from the disposal or other release of hazardous substances or wastes originating from properties PVR owns or operates, regardless of whether such disposal or release occurred during or prior to PVR's acquisition of such properties. See "—PVR Coal and Natural Resource Management Segment—Hazardous Materials and Waste." Although petroleum, including natural gas and NGLs are generally excluded from CERCLA's definition of "hazardous substance," PVR's natural gas midstream operations do generate wastes in the course of ordinary operations that may fall within the definition of a "hazardous substance."

PVR's natural gas midstream operations generate wastes, including some hazardous wastes, which are subject to RCRA and comparable state laws. However, RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy. Unrecovered petroleum product wastes, however, may still be regulated under RCRA as solid waste. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas and NGLs in pipelines may also generate some hazardous wastes. Although PVR believes that it is unlikely that the RCRA exemption will be repealed in the near future, repeal would increase costs for waste disposal and environmental remediation at PVR's facilities.

PVR currently owns or leases numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas and NGLs. Although PVR believes that the operators of such properties used operating and disposal practices that were standard in the industry at the time, hydrocarbons or wastes may have been disposed of or released on or under such properties or on or under other locations where such wastes have been taken for disposal. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, PVR could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination, whether from prior owners or operators or other historic activities or spills) or to perform remedial plugging or pit closure operations to prevent future contamination. PVR has ongoing remediation projects underway at several sites, but it does not believe that the costs associated with such cleanups will have a material adverse impact on PVR's operations or revenues.

Water Discharges. PVR's natural gas midstream operations are subject to the CWA. See "—PVR Coal and Natural Resource Management Segment—Clean Water Act." Any unpermitted release of pollutants, including NGLs or condensates, from PVR's systems or facilities could result in fines or penalties as well as significant remedial obligations.

OSHA. PVR's natural gas midstream operations are subject to OSHA. See "—Oil and Gas Segment—OSHA."

Employees and Labor Relations

We and our subsidiaries had a total of 314 employees at December 31, 2007, including 129 employees who directly provide services for PVR. We consider our current employee relations to be favorable.

Available Information

Our internet address is http://www.pennvirginia.com. We make available free of charge on or through our internet website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Audit Committee Charter, Compensation and Benefits Committee Charter and Nominating and Governance Committee Charter and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, or the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission, or the SEC.

Executive Officers of the Company

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

Name	Age	Position with the Company
A. James Dearlove	60	President and Chief Executive Officer
Keith D. Horton	54	Executive Vice President
Ronald K. Page	57	Vice President
Frank A. Pici	52	Executive Vice President and Chief Financial Officer
Nancy M. Snyder	54	Executive Vice President, General Counsel and Corporate Secretary
H. Baird Whitehead	57	Executive Vice President

A. James Dearlove has served as our President and Chief Executive Officer since May 1996 and as a director since February 1996, as our President and Chief Operating Officer from 1994 to May 1996, as our Senior Vice President from 1992 to 1994 and as our Vice President from 1986 to 1992. Mr. Dearlove has also served as Chief Executive Officer and Chairman of the Board of PVG GP, LLC, the general partner of Penn Virginia GP Holdings, L.P., since September 2006 and as Chief Executive Officer and Chairman of the Board of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P., since July 2001 and December 2002. Mr. Dearlove also serves as a director of the National Council of Coal Lessors.

Keith D. Horton has served as our Executive Vice President and as a director since December 2000, as Vice President—Eastern Operations from February 1999 to December 2000, as Vice President from February 1996 to February 1999, as President of Penn Virginia Coal Company from February 1996 to October 2001, as Vice President of Penn Virginia Coal Company from March 1994 to February 1996, as Vice President of Penn Virginia Resources Corporation from January 1990 to December 1998 and as Manager, Coal Operations of Penn Virginia Resources Corporation from July 1982 to December 1989. Mr. Horton has also served as Co-President and Chief Operating Officer—Coal of Penn Virginia Resource GP, LLC since May 2006 and as President and Chief Operating Officer of Penn Virginia Resource GP, LLC from July 2001 to May 2006. Mr. Horton has also served as President of Penn Virginia Operating Co., LLC since September 2001. Mr. Horton serves as a director of the Virginia Mining Association, the Powell River Project and the Eastern Coal Council.

Ronald K. Page has served as our Vice President since May 2005 and as our Vice President, Corporate Development from July 2003 to May 2005. Mr. Page has also served as Co-President and Chief Operating Officer—Midstream of Penn Virginia Resource GP, LLC since May 2006 and as Vice President, Corporate Development of Penn Virginia Resource GP, LLC from July 2003 to May 2006. Mr. Page has also served as President of PVR Midstream LLC since January 2005. From January 1998 to May 2003, Mr. Page served in various positions with El Paso Field Services Company, including Vice President of Commercial Operations—Texas Pipelines and Processing from 2001 to 2003, Vice President of Business Development from 2000 to 2001 and Director of Business Development from 1999 to 2000.

Frank A. Pici has served as our Executive Vice President and Chief Financial Officer since September 2001. Mr. Pici has also served as Vice President and Chief Financial Officer and as a director of PVG GP, LLC since September 2006 and as Vice President and Chief Financial Officer and as a director of Penn Virginia Resource GP, LLC since September 2001 and October 2002. From 1996 to 2001, Mr. Pici served as Vice President—Finance and Chief Financial Officer of Mariner Energy, Inc., or Mariner, a Houston, Texas-based oil and gas exploration and production company, where he managed all financial aspects of Mariner, including accounting, tax, finance, banking, investor relations, planning and budgeting and information technology. From 1994 to 1996, Mr. Pici served as Corporate Controller of Cabot Oil & Gas Corporation, or Cabot, an oil and gas exploration and production company.

Nancy M. Snyder has served as our Executive Vice President since May 2006, as our Senior Vice President from February 2003 to May 2006, as our Vice President from December 2000 to February 2003 and as our General Counsel and Corporate Secretary since 1997. Ms. Snyder has also served as Vice President and General Counsel and as a director of PVG GP, LLC since September 2006 and as Vice President and General Counsel and as a director of Penn Virginia Resource GP, LLC since July 2001.

H. Baird Whitehead has served as our Executive Vice President since January 2001 and as President of Penn Virginia Oil & Gas Corporation since January 2001. Prior to joining the Company, Mr. Whitehead served in various positions with Cabot. From 1998 to 2001, Mr. Whitehead served as Senior Vice President during which time he oversaw Cabot's drilling, production and exploration activity in the Appalachian, Rocky Mountain, Mid-Continent and Gulf Coast areas. From 1992 to 1998, Mr. Whitehead served as Vice President and Regional Manager of Cabot's Appalachian business. From 1989 to 1992, Mr. Whitehead served as Vice President and Regional Manager of Cabot's Anadarko business unit.

Common Abbreviations and Definitions

The following are abbreviations and definitions commonly used in the coal and oil and gas industries that are used in this Annual Report on Form 10-K.

Bbl	a standard barrel of 42 U.S. gallons liquid volume
Bcf	one billion cubic feet
Bcfe	one billion cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
BTU	British thermal unit
CBM	coalbed methane
Developed acreage	lease acreage that is allocated or assignable to producing wells or wells capable of production
Development well	a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive
Dry hole	a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion of the well
Exploratory or exploration well	a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir
Gross acre or well	an acre or well in which a working interest is owned
Mbbl	one thousand barrels
Mbf	one thousand board feet
Mcf	one thousand cubic feet
Mcfe	one thousand cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
MMbbl	one million barrels
MMbf	one million board feet
MMbtu	one million British thermal units
MMcf	one million cubic feet
MMcfd	one million cubic feet per day
MMcfe	one million cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
Net acre or well	gross acres or wells multiplied by the owned working interest in those gross acres or wells

NGL	natural gas liquid
NYMEX	New York Mercantile Exchange
Present value of proved reserves	the present value (discounted at 10%) of estimated future cash flows from proved oil and natural gas reserves, as estimated by our independent engineers, reduced by additional estimated future operating expenses, development expenditures and abandonment costs (net of salvage value) associated therewith (before income taxes)
Probable coal reserves	those reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation
Productive wells	wells that are producing oil or gas or that are capable of production
Proved developed reserves	reserves that can be expected to be recovered through existing wells with existing equipment and operating methods
Proved reserves	those estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years
Proved undeveloped reserves	reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion
Proven coal reserves	those reserves for which: (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well defined, that the size, shape, depth and mineral content of reserves are well-established
Standardized measure	present value of proved reserves further reduced by the present value (discounted at 10%) of estimated future income taxes on cash flows using prices in effect at a fiscal year end and estimated future costs as of that fiscal year end. Prices are held constant throughout the life of the properties except where SEC guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations.
Undeveloped acreage	lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether such acreage contains estimated net proved reserves
Working interest	a cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease

Item 1A *Risk Factors*

Our business and operations are subject to a number of risks and uncertainties as described below. However, the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, financial condition or results of operations. If any of the following risks actually occur, our business, financial condition or results of operations could suffer.

Risks Related to Our Oil and Gas Business

Natural gas and crude oil prices are volatile, and a substantial or extended decline in prices would hurt our profitability and financial condition.

Our revenues, operating results, cash flow, profitability, future rate of growth and the carrying value of our oil and gas properties depend heavily on prevailing market prices for natural gas and crude oil. Historically, natural gas and crude oil prices have been volatile, and they are likely to continue to be volatile. Wide fluctuations in natural gas and crude oil prices may result from relatively minor changes in the supply of and demand for oil and gas, market uncertainty and other factors that are beyond our control, including:

- domestic and foreign supplies of oil and natural gas;
- political and economic conditions in oil or gas producing regions;
- overall domestic and foreign economic conditions;
- prices and availability of alternative fuels;
- the availability of transportation facilities;
- weather conditions; and
- domestic and foreign governmental regulation.

Some of our projections and estimates are based on assumptions as to the future prices of natural gas and crude oil. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future will likely differ from our estimates. Any substantial or extended decline in the actual prices of natural gas or crude oil would have a material adverse effect on our financial position and results of operations (including reduced cash flow and borrowing capacity and possible asset impairment), the quantities of natural gas and crude oil reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operations. We have historically succeeded in substantially replacing reserves through acquisitions, exploration and development. We have conducted such activities on our existing oil and gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from such activities at acceptable costs. Lower oil and gas prices may further limit the types of reserves that can be developed at acceptable costs. Lower prices also decrease our cash flows and may cause us to reduce capital expenditures. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves if cash flows from operations are reduced and external sources of capital become limited or unavailable. In addition, exploration and development activities involve numerous risks that may result in dry holes, the failure to produce oil and gas in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than those we have consummated to date. However, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources substantially greater than those available to us. We cannot ensure that we will successfully consummate any acquisition, that we will be able to acquire producing oil and gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

We may not be able to fund our planned capital expenditures.

We make, and will continue to make, substantial capital expenditures to find, acquire, develop, exploit and produce oil and natural gas reserves. Our capital expenditures for oil and gas properties were $520.4 million for 2007, and we have budgeted total capital expenditures of approximately $475 million in 2008. If oil and gas prices decrease or we encounter operating difficulties that result in our cash flow from operations being less than expected, we may have to reduce the capital we can spend unless we raise additional funds through debt or equity financing. Debt or equity financing, cash generated by operations or borrowing capacity may not be available to us in sufficient amounts or on acceptable terms to meet these requirements.

Future cash flows and the availability of financing will be subject to a number of variables, such as:

- our success in locating and producing new reserves;
- the level of production from existing wells; and
- prices of oil and natural gas.

Issuing equity securities to satisfy our financing requirements could cause substantial dilution to existing shareholders. Debt financing could lead to us being more vulnerable to competitive pressures and economic downturns.

If our revenues were to decrease due to lower oil and natural gas prices, decreased production or other reasons, and if we could not obtain capital through our revolving credit facility or otherwise, our ability to execute our development plans, replace our reserves or maintain production levels could be greatly limited.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive natural gas or oil reserves will be found. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- shortages or delays in the availability of drilling rigs and the delivery of equipment;
- shortages in experienced labor;
- failure to secure necessary regulatory approvals and permits;
- fires, explosions, blow-outs and surface cratering; and
- adverse weather conditions.

The prevailing prices of oil and gas also affect the cost of and the demand for drilling rigs, production equipment and related services. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays which jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that natural gas or oil is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry wells or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, nor can we be sure that our overall drilling success rate or our drilling success rate for activity within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our results of operations and financial condition. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.

We are exposed to the credit risk of our customers, and nonpayment or nonperformance by our customers would reduce our cash flows.

We are subject to risk from loss resulting from our customers' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of revenues from our oil and gas segment. In 2007, two of our oil and gas customers accounted for 35% of our natural gas and oil and condensate revenues and 12% of our total consolidated revenues. Any nonpayment or nonperformance by our oil and gas customers would reduce our cash flows.

Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for, and the production and transportation of oil and natural gas. These operating risks include:

- fires, explosions, blowouts, cratering and casing collapses;
- formations with abnormal pressures;
- pipeline ruptures or spills;
- uncontrollable flows of oil, natural gas or well fluids;
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases; and
- natural disasters.

Any of these risks could result in substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. In addition, under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our financial condition and operations.

Our business depends on transportation facilities owned by others.

We deliver substantially all of our oil and natural gas production through pipelines that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines as well as gathering systems and processing facilities. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and market our oil and natural gas.

Estimates of oil and natural gas reserves are not precise.

This Annual Report on Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and, therefore, changes often occur as these variables evolve and commodity prices fluctuate.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

At December 31, 2007, approximately 41% of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

You should not assume that the present value of estimated future net cash flows (standardized measure) referred to herein is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided herein. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for us.

We have limited control over the activities on properties we do not operate.

Other companies operate a portion of our net production. In 2007, other companies operated approximately 17% of our net production. Our success in properties operated by others will depend upon a number of factors outside of our control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

Certain working interest owners in our properties have the right to control the timing of drilling activities on our properties under certain circumstances.

Under certain circumstances, certain of the other working interest owners in our properties have the right to limit the amount of drilling activities that can take place on our properties at any given time. If these working interest owners chose to exercise this right, we could be required to scale back anticipated drilling activities on the affected properties. In such an event, production from the affected properties would be deferred, thereby decreasing production from the properties in the short-term.

Our producing property acquisitions carry significant risks.

Acquisition of producing oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. The success of any acquisition will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future oil and gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results, and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Responses to recent coal mining accidents could have an adverse effect on our operations.

Our conventional and CBM drilling operations in Appalachia take place in close proximity to coal mining operations. Recent coal mining disasters in West Virginia and Kentucky have received state and national attention that is resulting in increased scrutiny of current safety practices and procedures at and around coal mining operations. This scrutiny could result in the promulgation of more stringent regulations for the permitting of oil and gas wells in close proximity to coal mining operations, which could make it more difficult, time consuming and costly for us to obtain such permits and could adversely affect our natural gas production and reduce our oil and natural gas revenues.

Derivative transactions may limit our potential gains and involve other risks.

In order to manage our exposure to price risks in the sale of our oil and natural gas, we periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of two years or less. While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains if oil or natural gas prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how oil or natural gas prices fluctuate in the future.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

In addition, derivative instruments involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and gas are subject to extensive federal, state and local laws and regulations, including complex environmental laws. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals or a failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations, we may be charged with remedial costs. Laws and regulations protecting the environment have become more stringent in recent years, and may, in some circumstances, result in liability for environmental damage regardless of negligence or fault. In addition, pollution and similar environmental risks generally are not fully insurable. These liabilities and costs could have a material adverse effect on our financial condition and results of operations. See Item 1, "Business—Government Regulation and Environmental Matters—Oil and Gas Segment—Environmental Matters."

Risks Related to Our Ownership Interests in PVG and PVR

We are not the only partners of PVG and PVR, and PVG's and PVR's respective partnership agreements require them to distribute all available cash to their respective partners, including public unitholders.

PVG and PVR are publicly traded limited partnerships. We own PVG GP, LLC, the sole general partner of PVG. As of December 31, 2007, we also owned an approximately 82% limited partner interest in PVG. As of December 31, 2007, PVG owned approximately 44% of PVR, consisting of a 2% general partner interest and an approximately 42% limited partner interest in PVR, as well as the incentive distribution rights in PVR. We directly owned an additional 0.5% limited partner interest in PVR as of December 31, 2007. The remainder of the outstanding limited partner interests in each of PVG and PVR are owned by public unitholders. Although PVG's and PVR's respective partnership agreements require them to distribute, on a quarterly basis, 100% of their available cash to their respective unitholders of record and their respective general partners, we are not the only limited partners of PVG and PVR and, therefore, we receive only our proportionate share of cash distributions from each of PVG and PVR based on our partner interests in each of them. The remainder of the quarterly cash distributions are distributed, pro rata, to the public unitholders.

For each of PVG and PVR, available cash is generally all cash on hand at the end of each quarter, after payment of fees and expenses and the establishment of cash reserves by their respective general partners. PVG's and PVR's general partners determine the amount and timing of cash distributions by PVG and PVR and have broad discretion to establish and make additions to the respective partnership's reserves or the reserves of the respective partnership's operating subsidiaries in amounts the general partner determines to be necessary or appropriate:

- to provide for the proper conduct of the business and the businesses of the operating subsidiaries (including reserves for future capital expenditures and for anticipated future credit needs);
- to provide funds for distributions to the respective unitholders and the respective general partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any loan or other agreements.

Accordingly, cash distributions we receive on our partner interests in PVG and PVR may be reduced at any time, or we may not receive any cash distributions from PVG or PVR, which would in turn reduce our cash available to service our debt.

PVG's ability to make distributions to us is entirely dependent upon PVG's receiving distributions from PVR, and the amount of cash that PVR will be able to distribute to its unitholders, including PVG, principally depends upon the amount of cash it can generate from its coal and natural gas midstream businesses.

PVG's earnings and cash flow consist exclusively of cash distributions from PVR. Consequently, a significant decline in PVR's earnings or cash distributions would have a negative impact on its distributions to its partners, including us. The amount of cash that PVR will be able to distribute to its partners, including PVG, each quarter principally depends upon the amount of cash it can generate from its coal and natural resource management and natural gas midstream businesses. The amount of cash that PVR will generate will fluctuate from quarter to quarter based on, among other things:

- the amount of coal its lessees are able to produce;
- the price at which its lessees are able to sell the coal;
- its lessees' timely receipt of payment from their customers;
- the amount of natural gas transported in its gathering systems;
- the amount of throughput in its processing plants;
- the price of natural gas;
- the price of NGLs;
- the relationship between natural gas and NGL prices;
- the fees it charges and the margins it realizes for its natural gas midstream services; and

- its hedging activities.

In addition, the actual amount of cash that PVR will have available for distribution will depend on other factors, some of which are beyond its control, including:

- the level of capital expenditures it makes;
- the cost of acquisitions, if any;
- its debt service requirements;
- fluctuations in its working capital needs;
- restrictions on distributions contained in its debt agreements;
- prevailing economic conditions; and
- the amount of cash reserves established by its general partner in its sole discretion for the proper conduct of its business.

Because of these factors, PVR may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. If PVR reduces its per unit distribution, PVG will have less cash available for distribution to its unitholders, including us, and would probably be required to reduce its per unit distribution to its unitholders, including us. You should also be aware that the amount of cash that PVR has available for distribution depends primarily upon PVR's cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, PVR may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records profits.

In addition, the timing and amount, if any, of an increase or decrease in distributions by PVR to its unitholders will not necessarily be comparable to the timing and amount of any changes in distributions made by PVG. PVG's ability to distribute cash received from PVR to its unitholders, including us, is limited by a number of factors, including:

- restrictions on distributions contained in any future debt agreements;
- PVG's estimated general and administrative expenses, including expenses it will incur as a result of being a public company as well as other operating expenses;
- expenses of PVR's general partner and PVR;
- reserves necessary for PVG to make the necessary capital contributions to maintain its 2% general partner interest in PVR, as required by PVR's partnership agreement upon the issuance of additional partnership securities by PVR; and
- reserves PVG's general partner believes prudent for PVG to maintain the proper conduct of its business or to provide for future distributions by PVG.

A reduction in PVR's distributions will disproportionately affect the amount of cash distributions to which PVG is currently entitled, and, consequently, will affect the amount of cash distributions PVG is able to make to its unitholders, including us.

PVG's ownership of the incentive distribution rights in PVR, through PVG's ownership of PVR's general partner, the holder of the incentive distribution rights, entitles PVG to receive its pro rata share of specified percentages of total cash distributions made by PVR with respect to any particular quarter only in the event that PVR distributes more than $0.275 per unit for such quarter. As a result, the holders of PVR's common units have a priority over the holders of PVR's incentive distribution rights to the extent of cash distributions by PVR up to and including $0.275 per unit for any quarter.

PVG's incentive distribution rights entitle it to receive increasing percentages, up to 48%, of incremental cash distributions above $1.50 per unit, on an annualized basis, distributed by PVR. Because PVG is at the maximum target cash distribution level on the incentive distribution rights, future growth in distributions PVG receives from PVR, and in distributions we receive from PVG, will not result from an increase in the target cash distribution level associated with the incentive distribution rights. Furthermore, a decrease in the amount of distributions by PVR to less than $0.375 per unit per quarter would reduce PVG's percentage of the incremental cash distributions above $0.325 per common unit per quarter from 48% to 23%, consequently resulting in less cash available to PVG to distribute to its unitholders, including us. A decrease in the amount of distribution by PVR and, consequently, PVG may be caused by a variety of circumstances. PVR may generate less cash available for distributions or determine to create larger reserves in computing cash available for distribution. Even if cash available for distribution remained stable, PVG and PVR may determine to modify the incentive distribution rights to reduce the percentage of incremental cash distributions such incentive distribution rights are entitled to receive.

PVR may issue additional limited partner interests or other equity securities, which may increase the risk that PVR will not have sufficient available cash to maintain or increase its cash distribution level, which in turn may reduce the available cash that PVG has to distribute to its unitholders, including us.

PVR has wide latitude to issue additional limited partner interests on the terms and conditions established by its general partner. PVG receives cash distributions from PVR on the general partner interest, incentive distribution rights and the limited partner interest that PVG holds. Because a majority of the cash PVG receives from PVR is attributable to PVG's ownership of the incentive distribution rights, payment of distributions on additional PVR limited partner interests may increase the risk that PVR will be unable to maintain or increase its quarterly cash distribution per unit, which in turn may reduce the amount of incentive distributions PVG receives and the available cash that PVG has to distribute to its unitholders, including us.

Conflicts of interest may arise because the board of directors of the respective general partners of PVG and PVR have a fiduciary duty to manage the general partners in a manner that is beneficial to their owners, and at the same time, in a manner that is beneficial to the respective unitholders of PVG and PVR.

We own the sole general partner of PVG and PVG owns the sole general partner of PVR. PVG and PVR are publicly traded limited partnerships. Each of the board of directors of the general partners owes a fiduciary duty to the respective unitholders of PVG and PVR, and not just to us and PVG as owners of the general partners. As a result of these conflicts, the board of directors of the general partners of PVG and PVR may favor the interests of the public unitholders of PVG and PVR over the interests of the respective owners of the general partners.

Our ability to sell our common units of PVG, and PVG's ability to sell its partner interests in PVR, may be limited by securities law restrictions and liquidity constraints.

As of December 31, 2007, we owned 32,087,424 common units of PVG and PVG owned 19,587,049 common units of PVR, all of which are unregistered and restricted securities within the meaning of Rule 144 under the Securities Act of 1933, or the Securities Act. Unless we or PVG were to register these units, we or PVG are limited to selling into the market in any three-month period an amount of PVG common units or PVR common units that does not exceed the greater of 1% of the total number of common units outstanding or the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale. In addition, PVG faces contractual limitations on its ability to sell its general partner interest and incentive distribution rights in PVR and the market for such interests is illiquid.

Congress is considering proposed legislation that may, if enacted, negatively impact the value of our limited partner interests in PVG by precluding PVG from qualifying for treatment as a partnership for U.S. federal income tax purposes under the publicly traded partnership rules.

In response to recent public offerings of interests in the management operations of private equity funds and hedge funds, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704(d) Internal Revenue Code and changing the characterization of certain types of income received from partnerships. In particular, one proposal recharacterizes certain income and gain received with respect to "investment service partnership interests" as ordinary income for the performance of services, which may not be treated as qualifying income for publicly traded partnerships. As such proposal is currently interpreted, a significant portion of PVG's interests in PVR may be viewed as an investment service partnership interest. Although we are unable to predict whether the proposed legislation, or any other proposals, will ultimately be enacted, the enactment of any such legislation could negatively impact the value of our limited partner interests in PVG.

Risks Related to PVR's Coal and Natural Resource Management Business

If PVR's lessees do not manage their operations well, their production volumes and PVR's coal royalties revenues could decrease.

PVR depends on its lessees to effectively manage their operations on its properties. PVR's lessees make their own business decisions with respect to their operations, including decisions relating to:

- the method of mining;
- credit review of their customers;
- marketing of the coal mined;
- coal transportation arrangements;
- negotiations with unions;
- employee hiring and firing;
- employee wages, benefits and other compensation;
- permitting;
- surety bonding; and
- mine closure and reclamation.

If PVR's lessees do not manage their operations well, their production could be reduced, which would result in lower coal royalties revenues to PVR and could adversely affect PVR's ability to make its quarterly distributions.

The coal mining operations of PVR's lessees are subject to numerous operational risks that could result in lower coal royalties revenues.

PVR's coal royalties revenues are largely dependent on the level of production from its coal reserves achieved by its lessees. The level of PVR's lessees' production is subject to operating conditions or events that may increase PVR's lessees' cost of mining and delay or halt production at particular mines for varying lengths of time and that are beyond their or its control, including:

- the inability to acquire necessary permits;
- changes or variations in geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposit;
- changes in governmental regulation of the coal industry;
- mining and processing equipment failures and unexpected maintenance problems;
- adverse claims to title or existing defects of title;
- interruptions due to power outages;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions;
- employee injuries or fatalities; and
- fires and explosions.

Any interruptions to the production of coal from PVR's reserves could reduce its coal royalties revenues and adversely affect its ability to make its quarterly distributions. In addition, PVR's coal royalties revenues are based upon sales of coal by its lessees to their customers. If PVR's lessees do not receive payments for delivered coal on a timely basis from their customers, their cash flow would be adversely affected, which could cause PVR's cash flow to be adversely affected and could adversely affect PVR's ability to make its quarterly distributions.

A substantial or extended decline in coal prices could reduce PVR's coal royalties revenues and the value of PVR's coal reserves.

A substantial or extended decline in coal prices from recent levels could have a material adverse effect on PVR's lessees' operations (including mine closures) and on the quantities of coal that may be economically produced from its properties. This, in turn, could reduce PVR's coal royalties revenues, its coal services revenues and the value of its coal reserves. Additionally, volatility in coal prices could make it difficult to estimate with precision the value of PVR's coal reserves and any coal reserves that PVR may consider for acquisition.

PVR depends on a limited number of primary operators for a significant portion of its coal royalties revenues and the loss of or reduction in production from any of PVR's major lessees could reduce its coal royalties revenues.

PVR depends on a limited number of primary operators for a significant portion of its coal royalties revenues. In 2007, five primary operators, each with multiple leases, accounted for 65% of PVR's coal royalties revenues and 7% of our total consolidated revenues. If any of these operators enters bankruptcy or decides to cease operations or significantly reduce its production, PVR's coal royalties revenues could be reduced.

A failure on the part of PVR's lessees to make coal royalty payments could give PVR the right to terminate the lease, repossess the property or obtain liquidation damages and/or enforce payment obligations under the lease. If PVR repossessed any of its properties, PVR would seek to find a replacement lessee. PVR may not be able to find a replacement lessee and, if it finds a replacement lessee, PVR may not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing lessee could be subject to bankruptcy proceedings that could further delay the execution of a new lease or the assignment of the existing lease to another operator. If PVR enters into a new lease, the replacement operator might not achieve the same levels of production or sell coal at the same price as the lessee it replaced. In addition, it may be difficult for PVR to secure new or replacement lessees for small or isolated coal reserves, since industry trends toward consolidation favor larger-scale, higher technology mining operations to increase productivity rates.

PVR's coal business will be adversely affected if PVR is unable to replace or increase its coal reserves through acquisitions.

Because its reserves decline as its lessees mine its coal, PVR's future success and growth depends, in part, upon its ability to acquire additional coal reserves that are economically recoverable. If PVR is unable to negotiate purchase contracts to replace or increase its coal reserves on acceptable terms, its coal royalties revenues will decline as its coal reserves are depleted. In addition, if PVR is unable to successfully integrate the companies, businesses or properties it is able to acquire, its coal royalties revenues may decline and PVR could, therefore, experience a material adverse effect on its business, financial condition or results of operations. If PVR acquires additional coal reserves, there is a possibility that any acquisition could be dilutive to earnings and reduce its ability to make distributions to unitholders or to pay interest on, or the principal of, its debt obligations. Any debt PVR incurs to finance an acquisition may similarly affect its ability to make distributions to unitholders or to pay interest on, or the principal of, its debt obligations. PVR's ability to make acquisitions in the future also could be limited by restrictions under its existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

PVR's lessees could satisfy obligations to their customers with coal from properties other than PVR's, depriving PVR of the ability to receive amounts in excess of the minimum coal royalty payments.

PVR does not control its lessees' business operations. PVR's lessees' customer supply contracts do not generally require its lessees to satisfy their obligations to their customers with coal mined from PVR's reserves. Several factors may influence a lessee's decision to supply its customers with coal mined from properties PVR does not own or lease, including the royalty rates under the lessee's lease with PVR, mining conditions, transportation costs and availability and customer coal quality specifications. If a lessee satisfies its obligations to its customers with coal from properties PVR does not own or lease, production under its lease will decrease, and PVR will receive lower coal royalties revenues.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal mined from PVR's properties.

Transportation costs represent a significant portion of the total cost of coal for the customers of PVR's lessees. Increases in transportation costs could make coal a less competitive source of energy or could make coal produced by some or all of PVR's lessees less competitive than coal produced from other sources. On the other hand, significant decreases in transportation costs could result in increased competition for PVR's lessees from coal producers in other parts of the country or increased imports from offshore producers.

PVR's lessees depend upon rail, barge, trucking, overland conveyor and other systems to deliver coal to their customers. Disruption of these transportation services due to weather-related problems, strikes, lockouts, bottlenecks, mechanical failures and other events could temporarily impair the ability of PVR's lessees to supply coal to their customers. PVR's lessees' transportation providers may face difficulties in the future and impair the ability of its lessees to supply coal to their customers, thereby resulting in decreased coal royalties revenues to PVR.

PVR's lessees could experience labor disruptions, and PVR's lessees' workforces could become increasingly unionized in the future.

Two of PVR's lessees each has one mine operated by unionized employees. One of the mines operated by unionized employees was PVR's second largest mine on the basis of coal production as of December 31, 2007. All of PVR's lessees could become increasingly unionized in the future. If some or all of PVR's lessees' non-unionized operations were to become unionized, it could adversely affect their productivity and increase the risk of work stoppages. In addition, PVR's lessees' operations may be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against its lessees' operations. Any further unionization of PVR's lessees' employees could adversely affect the stability of production from its coal reserves and reduce its coal royalties revenues.

PVR's coal reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of PVR's coal reserves.

PVR's estimates of its coal reserves may vary substantially from the actual amounts of coal its lessees may be able to economically recover. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond PVR's control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data;
- the amount of ultimately recoverable coal in the ground;
- the effects of regulation by governmental agencies; and
- future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

Actual production, revenues and expenditures with respect to PVR's coal reserves will likely vary from estimates, and these variations may be material. As a result, you should not place undue reliance on the coal reserve data provided by PVR.

Any change in fuel consumption patterns by electric power generators away from the use of coal could affect the ability of PVR's lessees to sell the coal they produce and thereby reduce PVR's coal royalties revenues.

According to the U.S. Department of Energy, domestic electric power generation accounts for approximately 90% of domestic coal consumption. The amount of coal consumed for domestic electric power generation is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants such as nuclear, natural gas, fuel oil and hydroelectric power and environmental and other governmental regulations. PVR believes that most new power plants will be built to produce electricity during peak periods of demand. Many of these new power plants will likely be fired by natural gas because of lower construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of the CAA may result in more electric power generators shifting from coal to natural gas-fired power plants. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal and Natural Resource Management Segment—Air Emissions."

Extensive environmental laws and regulations affecting electric power generators could have corresponding effects on the ability of PVR's lessees to sell the coal they produce and thereby reduce PVR's coal royalties revenues.

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants, which are the ultimate consumers of the coal PVR's lessees produce. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. There is also continuing pressure on state and federal regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. As a result of these current and proposed laws, regulations and trends, electricity generators may elect to switch to other fuels that generate less of these emissions, possibly further reducing demand for the coal that PVR's lessees produce and thereby reducing its coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal and Natural Resource Management Segment—Air Emissions."

Delays in PVR's lessees obtaining mining permits and approvals, or the inability to obtain required permits and approvals, could have an adverse effect on PVR's coal royalties revenues.

Mine operators, including PVR's lessees, must obtain numerous permits and approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. The public has the right to comment on many permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required by PVR's lessees to conduct operations may not be issued, maintained or renewed, may not be issued or renewed in a timely fashion, or may involve requirements that restrict PVR's lessees' ability to economically conduct their mining operations. Limitations on PVR's lessees' ability to conduct their mining operations due to the inability to obtain or renew necessary permits, or due to uncertainty, litigation or delays associated with the eventual issuance of these permits, could have an adverse effect on its coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal and Natural Resource Management Segment—Mining Permits and Approvals."

Uncertainty over the precise parameters of the Clean Water Act's regulatory scope and a recent federal district court decision may adversely impact PVR's coal lessees' ability to secure the necessary permits for their valley fill surface mining activities.

To dispose of mining overburden generated from surface mining activities, PVR's lessees often need to obtain government approvals, including Clean Water Act Section 404 permits to construct valley fills and sediment control ponds. Ongoing uncertainty over which waters are subject to the Clean Water Act may adversely impact PVR's lessees' ability to secure these necessary permits. In addition, a recent decision by a United States District Court in West Virginia invalidated a permit issued to one of PVR's lessees for the Republic No. 2 Mine and enjoined its lessee, Alex Energy, Inc., from taking any further actions under this permit. Although this ruling has been appealed, uncertainty over the correct legal standard for issuing Section 404 permits may lead to rulings invalidating other permits, additional challenges to various permits and additional delays and costs in applying for and obtaining new permits. Unless this decision is overturned or further limited in subsequent proceedings, the ruling and its collateral consequences could ultimately have an adverse effect on PVR's coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal and Natural Resource Management Segment—Clean Water Act," for more information about the litigation described above.

PVR's lessees' mining operations are subject to extensive and costly laws and regulations, which could increase operating costs and limit its lessees' ability to produce coal, which could have an adverse effect on PVR's coal royalties revenues.

PVR's lessees are subject to numerous and detailed federal, state and local laws and regulations affecting coal mining operations, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Numerous governmental permits and approvals are required for mining operations. PVR's lessees are required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment. The costs, liabilities and requirements associated with these regulations may be significant and time-consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations (or judicial interpretations of existing laws and regulations) may be adopted in the future that could materially affect PVR's lessees' mining operations, either through direct impacts such as new requirements impacting its lessees' existing mining operations, or indirect impacts such as new laws and regulations that discourage or limit coal consumers' use of coal. Any of these direct or indirect impacts could have an adverse effect on PVR's coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal and Natural Resource Management Segment."

Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, PVR does not believe violations by its lessees can be eliminated completely. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens and, to a lesser extent, the issuance of injunctions to limit or cease operations. PVR's lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If PVR's lessees are required to pay these costs and liabilities and if their financial viability is affected by doing so, then their mining operations and, as a result, PVR's coal royalties revenues and its ability to make distributions, could be adversely affected.

Recent mining accidents in West Virginia and Kentucky have received national attention and instigated responses at the state and national level that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal and Natural Resource Management Segment—Mine Health and Safety Laws," for a more detailed discussion of recently enacted legislation that addresses mine safety equipment, training and emergency reporting requirements. Implementing and complying with these new laws and regulations could adversely affect PVR's lessees' coal production and could therefore have an adverse effect on PVR's coal royalties revenues and its ability to make distributions.

Risks Related to PVR's Natural Gas Midstream Business

The success of PVR's natural gas midstream business depends upon its ability to find and contract for new sources of natural gas supply.

In order to maintain or increase system throughput levels on PVR's gathering systems and asset utilization rates at its processing plants, PVR must contract for new natural gas supplies. The primary factors affecting PVR's ability to connect new supplies of natural gas to its gathering systems include the level of drilling activity creating new gas supply near its gathering systems, PVR's success in contracting for existing natural gas supplies that are not committed to other systems and PVR's ability to expand and increase the capacity of its systems. PVR may not be able to obtain additional contracts for natural gas supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. PVR has no control over the level of drilling activity in its areas of operations, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, PVR has no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital.

PVR's natural gas midstream assets, including its gathering systems and processing plants, are connected to natural gas reserves and wells for which the production will naturally decline over time. PVR's cash flows associated with these systems will decline unless it is able to secure new supplies of natural gas by connecting additional production to these systems. A material decrease in natural gas production in PVR's areas of operation, as a result of depressed commodity prices or otherwise, would result in a decline in the volume of natural gas PVR handles, which would reduce its revenues and operating income. In addition, PVR's future growth will depend, in part, upon whether it can contract for additional supplies at a greater rate than the rate of natural decline in PVR's currently connected supplies.

The profitability of PVR's natural gas midstream business is dependent upon prices and market demand for natural gas and NGLs, which are beyond PVR's control and have been volatile.

PVR is subject to significant risks due to fluctuations in natural gas commodity prices. During 2007, PVR generated a majority of its gross processing margin from two types of contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs—percentage-of-proceeds and gas purchase/keep-whole arrangements. See Item 1, "Business—Contracts—PVR Natural Gas Midstream Segment."

Virtually all of the natural gas gathered on PVR's Crescent System and Hamlin System is contracted under percentage-of-proceeds arrangements. The natural gas gathered on PVR's Beaver System is contracted primarily under either percentage-of proceeds or gas purchase/keep-whole arrangements. Under both types of arrangements, PVR provides gathering and processing services for natural gas received. Under percentage-of-proceeds arrangements, PVR generally sells the NGLs produced from the processing operations and the remaining residue gas at market prices and remits to the producers an agreed upon percentage of the proceeds based upon an index price for the gas and the price received for the NGLs. Under these arrangements, revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have a material adverse effect on PVR's results of operations. Under gas purchase/keep-whole arrangements, PVR generally buys natural gas from producers based upon an index price and then sells the NGLs and the remaining residue gas to third parties at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the volume of natural gas available for sale, profitability is dependent on the value of those NGLs being higher than the value of the volume of gas reduction or "shrink." Under these arrangements, revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs. Accordingly, a change in the relationship between the price of natural gas and the price of NGLs could have a material adverse effect on PVR's results of operations.

In the past, the prices of natural gas and NGLs have been extremely volatile, and PVR expects this volatility to continue. The markets and prices for residue gas and NGLs depend upon factors beyond PVR's control. These factors include demand for oil, natural gas and NGLs, which fluctuates with changes in market and economic conditions, and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Acquisitions and expansions may affect PVR's business by substantially increasing the level of its indebtedness and contingent liabilities and increasing the risks of being unable to effectively integrate these new operations.

From time to time, PVR evaluates and acquires assets and businesses that it believes complement its existing operations. PVR may encounter difficulties integrating these acquisitions with its existing businesses without a loss of employees or customers, a loss of revenues, an increase in operating or other costs or other difficulties. In addition, PVR may not be able to realize the operating efficiencies, competitive advantages, cost savings or other benefits expected from these acquisitions. Future acquisitions may require substantial capital or the incurrence of substantial indebtedness. As a result, PVR's capitalization and results of operations may change significantly following an acquisition. Future acquisitions might not generate increases in PVR's cash distributions to its unitholders.

Expanding PVR's natural gas midstream business by constructing new gathering systems, pipelines and processing facilities subjects PVR to construction risks.

One of the ways PVR may grow its natural gas midstream business is through the construction of additions to existing gathering, compression and processing systems. The construction of a new gathering system or pipeline, the expansion of an existing pipeline through the addition of new pipe or compression and the construction of new processing facilities involve numerous regulatory, environmental, political and legal uncertainties beyond PVR's control and require the expenditure of significant amounts of capital. If PVR undertakes these projects, they may not be completed on schedule, or at all, or at the budgeted cost. Moreover, PVR's revenues may not increase immediately upon the expenditure of funds on a particular project. For example, the construction of gathering facilities requires the expenditure of significant amounts of capital, which may exceed PVR's estimates. Generally, PVR may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, PVR may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. As a result, there is the risk that new facilities may not be able to attract enough natural gas to achieve PVR's expected investment return, which could adversely affect its financial position or results of operations and its ability to make distributions to us.

If PVR is unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then PVR may be unable to fully execute its growth strategy and its cash flows could be reduced.

The construction of additions to PVR's existing gathering assets may require PVR to obtain new rights-of-way before constructing new pipelines. PVR may be unable to obtain rights-of-way to connect new natural gas supplies to its existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for PVR to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then PVR's cash flows could be reduced.

PVR is exposed to the credit risk of its natural gas midstream customers, and nonpayment or nonperformance by PVR's customers would reduce its cash flows.

PVR is subject to risk of loss resulting from nonpayment or nonperformance by its natural gas midstream customers. PVR depends on a limited number of customers for a significant portion of its natural gas midstream revenues. In 2007, three of PVR's natural gas midstream customers accounted for 53% of PVR's natural gas midstream revenues and 27% of our total consolidated revenues. Any nonpayment or nonperformance by PVR's natural gas midstream customers would reduce its cash flows.

Any reduction in the capacity of, or the allocations to, PVR in interconnecting third-party pipelines could cause a reduction of volumes processed, which could adversely affect PVR's revenues and cash flows.

PVR is dependent upon connections to third-party pipelines to receive and deliver residue gas and NGLs. Any reduction of capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures or other causes could result in reduced volumes gathered and processed in PVR's natural gas midstream facilities. Similarly, if additional shippers begin transporting volumes of residue gas and NGLs on interconnecting pipelines, PVR's allocations in these pipelines could be reduced. Any reduction in volumes gathered and processed in PVR's facilities could adversely affect its revenues and cash flows.

Natural gas derivative transactions may limit PVR's potential gains and involve other risks.

In order to manage PVR's exposure to price risks in the marketing of its natural gas and NGLs, PVR periodically enters into natural gas and NGL price hedging arrangements with respect to a portion of its expected production. PVR's hedges are limited in duration, usually for periods of two years or less. However, in connection with acquisitions, sometimes PVR's hedges are for longer periods. These hedging transactions may limit PVR's potential gains if natural gas or NGL prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, PVR may end up hedging too much or too little, depending upon how natural gas or NGL prices fluctuate in the future.

In addition, derivative transactions may expose PVR to the risk of financial loss in certain circumstances, including instances in which:

- PVR's production is less than expected;
- there is a widening of price basis differentials between delivery points for PVR's production and the delivery point assumed in the hedge arrangement;
- the counterparties to PVR's futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts natural gas or NGL prices.

In addition, derivative instruments involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

PVR's natural gas midstream business involves many hazards and operational risks, some of which may not be fully covered by insurance.

PVR's natural gas midstream operations are subject to the many hazards inherent in the gathering, compression, treating, processing and transportation of natural gas and NGLs, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs and other hydrocarbons; and
- fires and explosions.

These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of PVR's related operations. PVR's natural gas midstream operations are concentrated in Texas and Oklahoma, and a natural disaster or other hazard affecting these areas could have a material adverse effect on its operations. PVR is not fully insured against all risks incident to its natural gas midstream business. PVR does not have property insurance on all of its underground pipeline systems that would cover damage to the pipelines. PVR is not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect PVR's operations and financial condition.

Federal, state or local regulatory measures could adversely affect PVR's natural gas midstream business.

PVR owns and operates an 11-mile interstate natural gas pipeline that, pursuant to the NGA, is subject to the jurisdiction of the FERC. The FERC has granted PVR waivers of various requirements otherwise applicable to conventional FERC-jurisdictional pipelines, including the obligation to file a tariff governing rates, terms and conditions of open access transportation service. The FERC has determined that PVR will have to comply with the filing requirements if the natural gas company ever desires to apply for blanket transportation authority to transport third-party gas on the 11-mile pipeline. The FERC may revoke these waivers at any time.

PVR's natural gas gathering facilities generally are exempt from the FERC's jurisdiction under the NGA, but the FERC regulation nevertheless could change and significantly affect PVR's gathering business and the market for its services. For a more detailed discussion of how regulatory measures affect PVR's natural gas gathering systems, see Item 1, "Business—Government Regulation and Environmental Matters—PVR Natural Gas Midstream Segment."

Failure to comply with applicable federal and state laws and regulations can result in the imposition of administrative, civil and criminal remedies.

PVR's natural gas midstream business is subject to extensive environmental regulation.

Many of the operations and activities of PVR's gathering systems, plants and other facilities are subject to significant federal, state and local environmental laws and regulations. These include, for example, laws and regulations that impose obligations related to air emissions and discharge of wastes from PVR's facilities and the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by PVR or the prior owners of its natural gas midstream business or locations to which it or they have sent wastes for disposal. These laws and regulations can restrict or impact PVR's business activities in many ways, including restricting the manner in which it disposes of substances, requiring pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in PVR's natural gas midstream business due to its handling of natural gas and other petroleum products, air emissions related to its natural gas midstream operations, historical industry operations, waste disposal practices and the use by the prior owners of its natural gas midstream business of natural gas flow meters containing mercury. For example, an accidental release from one of PVR's pipelines or processing facilities could subject it to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase PVR's compliance costs and the cost of any remediation that may become necessary. PVR may incur material environmental costs and liabilities. Insurance may not provide sufficient coverage in the event an environmental claim is made. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Natural Gas Midstream Segment."

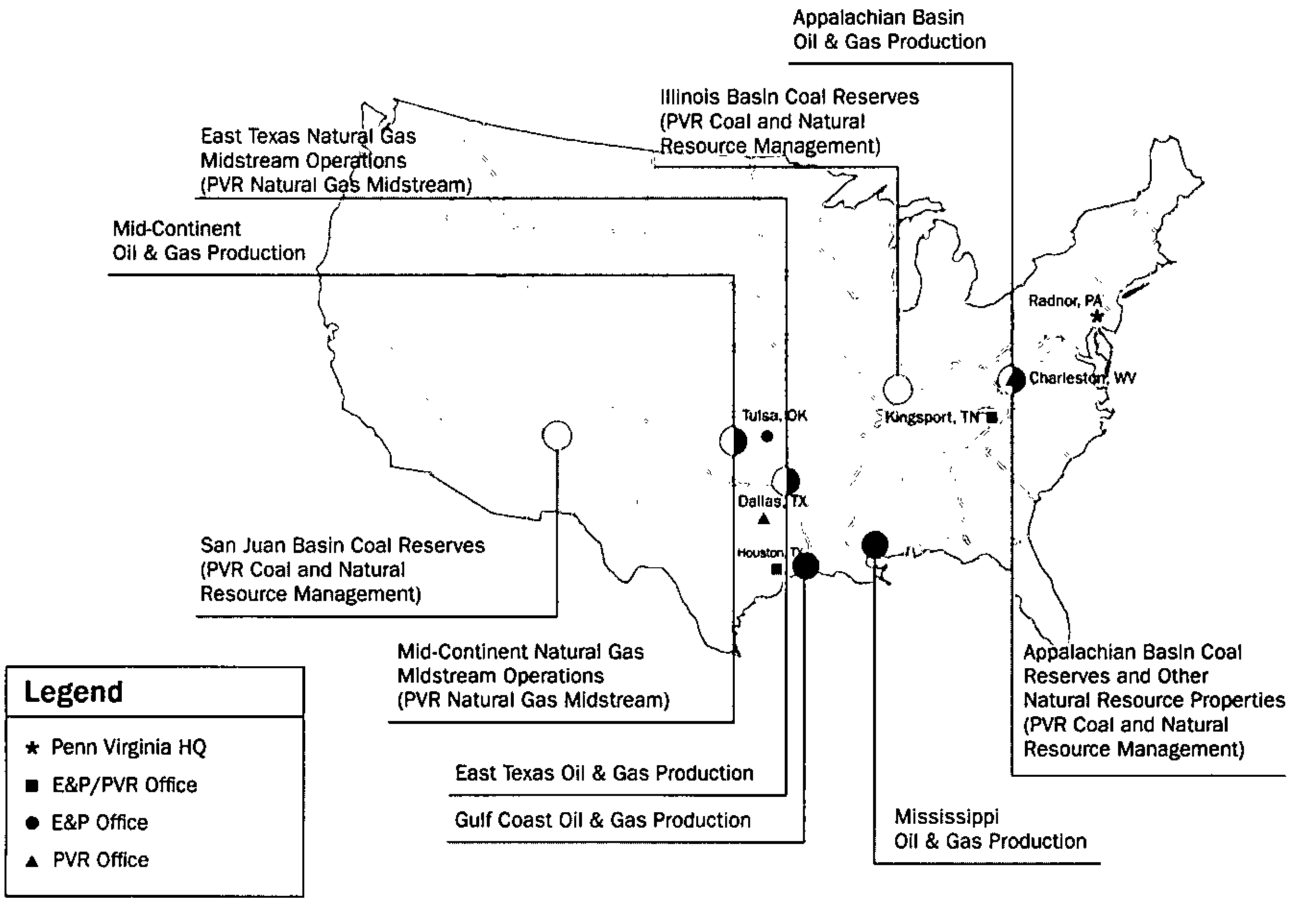
Item 1B *Unresolved Staff Comments*

We received no written comments from the SEC staff regarding our periodic or current reports under the Exchange Act within 180 days before the end of our fiscal year ended December 31, 2007.

Item 2 *Properties*

Title to Properties

The following map shows the general locations of our oil and gas production and exploration, PVR's coal reserves and related infrastructure investments and PVR's natural gas gathering and processing systems as of December 31, 2007:



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

Facilities

We are headquartered in Radnor, Pennsylvania, with additional offices in Oklahoma, Tennessee, Texas and West Virginia. All of our office facilities are leased, except for PVR's West Virginia office, which it owns. We believe that our properties are adequate for our current needs.

Oil and Gas Properties

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

Production and Pricing

The following table sets forth production, average sales prices and production costs with respect to our oil and gas properties for the years ended December 31, 2007, 2006 and 2005:

	2007	2006	2005
Production			
Oil and condensate (Mbbls)	461	382	302
Natural gas (MMcf)	37,802	28,968	25,550
Total production (MMcfe)	40,569	31,260	27,362
Average realized prices			
Natural gas ($/Mcf):			
Natural gas revenues, as reported	$ 6.94	$ 7.35	$ 8.31
Derivatives (gains) losses included in natural gas revenues	(0.01)	(0.02)	0.55
Natural gas revenues before impact of derivatives	6.93	7.33	8.86
Cash settlements on natural gas derivatives	0.39	0.37	(0.55)
Natural gas revenues, adjusted for derivatives	$ 7.32	$ 7.70	$ 8.31
Oil and condensate ($/Bbl):			
Oil and condensate revenues, as reported	$ 60.97	$ 55.59	$ 45.67
Derivatives (gains) losses included in oil and condensate revenues	1.09	1.20	2.84
Oil and condensate revenues before impact of derivatives	62.06	56.79	48.51
Cash settlements on crude oil derivatives	(1.59)	(0.58)	(2.84)
Oil and condensate revenues, adjusted for derivatives	$ 60.47	$ 56.21	$ 45.67
Production expenses ($/Mcfe)			
Lease operating	$ 1.15	$ 0.88	$ 0.63
Taxes other than income	0.44	0.38	0.48
General and administrative	0.40	0.41	0.34
Total production expenses	$ 1.99	$ 1.66	$ 1.45

Proved Reserves

The following table presents certain information regarding our proved reserves as of December 31, 2007, 2006 and 2005. The proved reserve estimates presented below were prepared by Wright and Company, Inc., independent petroleum engineers. For additional information regarding estimates of proved reserves, the preparation of such estimates by Wright and Company, Inc. and other information about our oil and gas reserves, see the Supplemental Information on Oil and Gas Producing Activities (Unaudited). Our estimates of proved reserves in the following table are consistent with those filed by us with other federal agencies.

	Natural Gas	Oil and Condensate	Natural Gas Equivalents	Standardized Measure (1)	Year-End Prices Used (2)	
	(Bcf)	(MMbbl)	(Bcfe)	($ millions)	$/MMBtu	$/Bbl
2007						
Developed	373	4.5	399	$187		
Undeveloped	215	10.7	281	788		
Total	588	15.2	680	$975	$6.80	$95.95
2006						
Developed	326	3.0	345	$545		
Undeveloped	131	1.9	142	60		
Total	457	4.9	487	$605	$5.64	$61.05
2005						
Developed	267	2.0	279	$833		
Undeveloped	92	0.9	98	203		
Total	359	2.9	377	$1,036	$10.08	$61.04

(1) Standardized measure is the present value of proved reserves further reduced by the present value (discounted at 10%) of estimated future income taxes on cash flows using prices in effect at a fiscal year end and estimated future costs as of

that fiscal year end. For information on the changes in the standardized measure of discounted future net cash flows, see the Supplemental Information on Oil and Gas Producing Activities (unaudited).

(2) Natural gas and oil prices were based on sales prices per Mcf and Bbl in effect at year end, with the representative price of natural gas adjusted for basis premium and BTU content to arrive at the appropriate net price.

In accordance with the SEC's guidelines, the engineers' estimates of future net revenues from our properties and the standardized measure thereof are based on oil and natural gas sales prices in effect as of December 31, 2007, and estimated future costs as of December 31, 2007. The prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. Prices for oil and gas are subject to substantial seasonal fluctuations as well as fluctuations resulting from numerous other factors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Proved reserves are the estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. Therefore, the standardized measure amounts shown above should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. The information set forth in the foregoing tables includes revisions of certain volumetric reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in production prices.

Production and Reserves by Region

The following table sets forth by region the estimated quantities of proved reserves as of December 31, 2007:

	Proved Reserves as of December 31, 2007		
Region	**Proved Reserves**	**% of Total Proved Reserves**	**% Proved Developed**
	(Bcfe)		
Appalachia	133	20%	90%
Mississippi	139	20%	73%
East Texas	292	43%	34%
Mid-Continent	80	12%	61%
Gulf Coast	36	5%	86%
Total	680	100%	

The following table sets forth by region the average daily production and total production for the years ended December 31, 2007, 2006 and 2005:

Region	Average Daily Production for the Year Ended December 31, 2007	2006	2005	Total Production for the Year Ended December 31, 2007	2006	2005
		(MMcfe)			(MMcf)	
Appalachia	34.0	35.0	37.8	12,424	12,759	13,812
Mississippi	20.7	17.6	14.2	7,551	6,411	5,185
East Texas	21.9	12.5	15.5	7,986	4,546	5,648
Mid-Continent	11.3	3.4	7.4	4,131	1,248	2,717
Gulf Coast	23.2	17.3	—	8,477	6,296	—
Total	111.1	85.8	74.9	40,569	31,260	27,362

Acreage

The following table sets forth our developed and undeveloped acreage at December 31, 2007. The acreage is located primarily in the Appalachian, Mississippi, East Texas, Mid-Continent and Gulf Coast regions of the United States.

	Gross Acreage	Net Acreage
	(in thousands)	
Developed	720	671
Undeveloped	932	617
Total	1,652	1,288

Wells Drilled

The following table sets forth the gross and net numbers of exploratory and development wells that we drilled during the years ended December 31, 2007, 2006 and 2005. The number of wells drilled refers to the number of wells reaching total depth at any time during the respective year. Net wells equals the number of gross wells multiplied by our working interest in each of the gross wells. Productive wells represent either wells which were producing or which were capable of commercial production.

	2007 Gross	2007 Net	2006 Gross	2006 Net	2005 Gross	2005 Net
Development						
Productive	265	198.5	187	138.9	163	130.8
Non-productive	6	5.1	3	2.4	3	3.0
Total development	271	203.6	190	141.3	166	133.8
Exploratory						
Productive	11	5.2	13	7.2	6	2.9
Non-productive	3	1.6	6	2.3	3	3.0
Under evaluation	4	2.6	1	1.0	3	2.5
Total exploratory	18	9.4	20	10.5	12	8.4
Total	289	213.0	210	151.8	178	142.2

The four exploratory wells under evaluation at the end of 2007 included two Devonian Shale wells in West Virginia, one New Albany Shale well in Illinois and one horizontal coalbed methane well in West Virginia. We expect to determine the commercial viability of these wells in 2008. At December 31, 2007, we had capitalized costs of $4.3 million related to these wells.

The exploratory well under evaluation at the end of 2006 was a Cotton Valley well in Texas. In 2007, we determined that this well was commercially viable and reclassified $1.1 million to wells, equipment and facilities based on the determination of proved reserves. At December 31, 2006, we had capitalized costs of $1.1 million related to this well.

The three exploratory wells under evaluation at the end of 2005 included two New Albany Shale wells in Illinois and a Bakken Dolomite horizontal oil well in Montana. In 2006, we determined that these wells were not commercially viable, resulting in a $3.8 million write-off.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we had a working interest at December 31, 2007. Productive wells are producing wells or wells capable of commercial production.

Operated Wells		Non-Operated Wells		Total	
Gross	Net	Gross	Net	Gross	Net
1,484	1,332	519	74	2,003	1,406

In addition to the above working interest wells, we own royalty interests in 2,429 gross wells.

Coal Reserves and Production

As of December 31, 2007, PVR owned or controlled approximately 818 million tons of proven and probable coal reserves located on approximately 397,000 acres (including fee and leased acreage) in Illinois, Kentucky, New Mexico, Virginia and West Virginia. PVR's coal reserves are in various surface and underground mine seams located on the following properties:

- Central Appalachia Basin: properties located in eastern Kentucky, southwestern Virginia and southern West Virginia;
- Northern Appalachia Basin: properties located in northern West Virginia;
- Illinois Basin: properties located in southern Illinois and western Kentucky; and
- San Juan Basin: properties located in the four corners area of New Mexico.

Coal reserves are coal tons that can be economically extracted or produced at the time of determination considering legal, economic and technical limitations. All of the estimates of PVR's coal reserves are classified as proven and probable reserves. Proven and probable reserves are defined as follows:

Proven Coal Reserves. Proven coal reserves are coal reserves for which: (i) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; (ii) grade and/or quality are computed from the results of detailed sampling; and (iii) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well defined, that the size, shape, depth and mineral content of reserves are well-established.

Probable Coal Reserves. Probable coal reserves are coal reserves for which quantity and grade and/or quality are computed from information similar to that used for proven coal reserves, but the sites for inspection, sampling and measurement are more widely spaced or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven coal reserves, is high enough to assume continuity between points of observation.

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

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

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

The following tables set forth production data and reserve information with respect to each of PVR's properties:

Property	Production for the Year Ended December 31, 2007	2006	2005
		(tons in millions)	
Central Appalachia	18.8	20.2	19.0
Northern Appalachia	4.2	5.0	5.0
Illinois Basin	3.8	2.5	1.4
San Juan Basin	5.7	5.1	4.8
Total	32.5	32.8	30.2

Property	Proven and Probable Reserves as of December 31, 2007					
	Underground	Surface	Total	Steam	Metallurgical	Total
			(tons in millions)			
Central Appalachia	413.8	155.5	569.3	481.1	88.2	569.3
Northern Appalachia	29.6	0.1	29.7	29.7	—	29.7
Illinois Basin	156.6	11.9	168.5	168.5	—	168.5
San Juan Basin	—	50.9	50.9	50.9	—	50.9
Total	600.0	218.4	818.4	730.2	88.2	818.4

The following table sets forth the coal reserves PVR owns and leases with respect to each of its coal properties as of December 31, 2007:

Property	Owned	Leased	Total
		(tons in millions)	
Central Appalachia	428.1	141.2	569.3
Northern Appalachia	29.7	—	29.7
Illinois Basin	139.5	29.0	168.5
San Juan Basin	47.0	3.9	50.9
Total	644.3	174.1	818.4

The following table sets forth PVR's coal reserve activity for each of its coal properties for the years ended December 2007, 2006 and 2005:

	2007	2006	2005
		(tons in millions)	
Reserves—beginning of year	765.4	689.1	557.3
Purchase of coal reserves	60.0	96.2	162.1
Tons mined by lessees	(32.5)	(32.8)	(30.2)
Revisions of estimates and other	25.5	12.9	(0.1)
Reserves—end of year	818.4	765.4	689.1

Other Natural Resource Management Assets

Coal Preparation and Loading Facilities

PVR generates coal services revenues from fees it charges to its lessees for the use of its coal preparation and loading facilities, which are located in Virginia, West Virginia and Kentucky. The facilities provide efficient methods to enhance lessee production levels and exploit PVR's coal reserves.

Timber and Oil and Gas Royalty Interests

PVR owns approximately 220,000 acres of forestland in Kentucky, Virginia and West Virginia. Approximately 28% of PVR's forestland is located on the 62,000 acres in West Virginia that PVR acquired in September 2007. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments," for a discussion of PVR's forestland acquisition. The balance of PVR's forestland is located on properties that also contain its coal reserves.

PVR owns royalty interests in approximately 11.2 Bcfe of proved oil and gas reserves located on approximately 165,000 acres in Kentucky, Virginia and West Virginia. Approximately 40% of PVR's oil and gas royalty interests are associated with the leases of property in eastern Kentucky and southwestern Virginia that PVR acquired in October 2007. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions, Dispositions and Investments," for a discussion of PVR's oil and gas royalty interest acquisition.

Natural Gas Midstream Systems

PVR's natural gas midstream operations currently include three natural gas gathering and processing systems and a stand-alone natural gas gathering system, including: (i) the Beaver/Perryton gathering and processing facilities in the Texas/Oklahoma panhandle area, (ii) the Crescent gathering and processing facilities in central Oklahoma, (iii) the Hamlin gathering and processing facilities in west-central Texas and (iv) the Arkoma gathering system in eastern Oklahoma. These systems include approximately 3,682 miles of natural gas gathering pipelines and three natural gas processing facilities, which have 160 MMcfd of total capacity. PVR's natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. PVR owns, leases or has rights-of-way to the properties where the majority of its natural gas midstream facilities are located.

The following table sets forth information regarding PVR's natural gas midstream assets:

Asset	Type	Approximate Length (Miles)	Approximate Number of Wells Connected	Current Processing Capacity (MMcfd)	Year Ended December 31, 2007 Average System Throughput (MMcfd)	Year Ended December 31, 2007 Utilization of Processing Capacity (%)
Beaver/Perryton System	Gathering pipelines and processing facility	1,421	1,044	100	126 (1)	100%
Crescent System	Gathering pipelines and processing facility	1,680	865	40	20	50%
Hamlin System	Gathering pipelines and processing facility	503	220	20	7	37%
Arkoma System	Gathering pipelines	78	79	—	13 (2)	
		3,682	2,208	160	166	

(1) Includes gas processed at other systems connected to the Beaver/Perryton System via the pipeline acquired in June 2006.

(2) Gathering-only volumes.

PVR expects to place a new Spearman natural gas processing plant in service by April 2008. The Spearman natural gas processing plant will have 60 MMcfd of inlet capacity. The Spearman natural gas processing plant will process gas gathered on the Spearman system. The new Spearman plant will create space in the Beaver natural gas processing plant for the gas that is currently bypassing the Beaver plant.

General. PVR is currently constructing a new natural gas gathering system located in the southeast portion of Harrison County, Texas (the Crossroads System). The Crossroads natural gas processing plant will have 80 MMcfd of inlet capacity. The Crossroads System will consist of approximately eight miles of natural gas gathering pipelines, ranging in size from eight to twelve inches in diameter, and the Crossroads natural gas processing plant. The Crossroads System will also include approximately 19 miles of six-inch NGL pipeline to transport the NGLs produced at the Crossroads plant to Panola Pipeline. The Crossroads System is expected to begin operations by April 2008.

Item 3 ***Legal Proceedings***

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject. See Item 1, "Business—Government Regulation and Environmental Matters," for a more detailed discussion of our material environmental obligations.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2007.

Part II

Item 5 ***Market for the Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities***

Market Information

Our common stock is traded on the NYSE under the symbol "PVA." The high and low sales prices (composite transactions) and dividends paid for each fiscal quarter in 2007 and 2006 were as follows:

Quarter Ended	Sales Price (1) High	Sales Price (1) Low	Cash Dividends Declared (1)
December 31, 2007	$49.56	$40.94	$0.05625
September 30, 2007	$44.50	$35.68	$0.05625
June 30, 2007	$43.25	$36.51	$0.05625
March 31, 2007	$37.16	$31.95	$0.05625
December 31, 2006	$38.35	$29.87	$0.05625
September 30, 2006	$36.33	$30.14	$0.05625
June 30, 2006	$38.61	$29.90	$0.05625
March 31, 2006	$36.23	$28.30	$0.05625

(1) On May 8, 2007, our board of directors approved a two-for-one split of our common stock in the form of a 100% dividend payable on June 19, 2007 to shareholders of record on June 12, 2007. Shareholders received one additional share of common stock for each share held on the record date. The sales prices and quarterly dividends have been adjusted to give retroactive effect to the stock split.

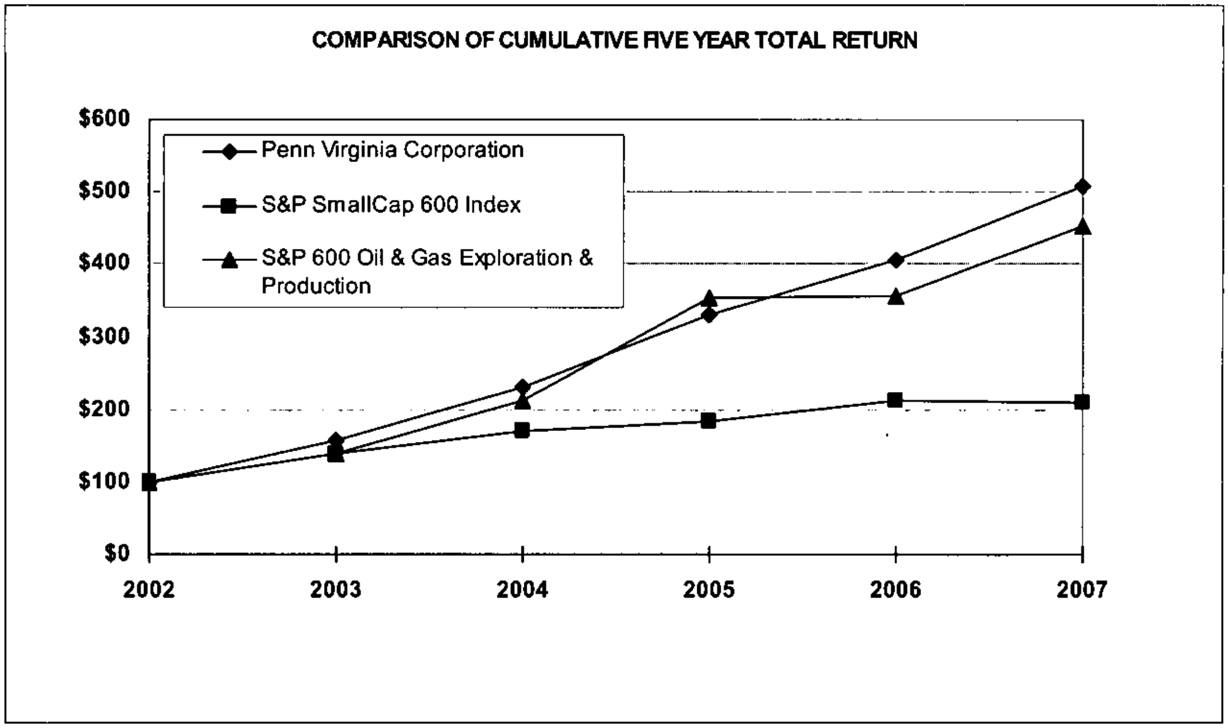
Equity Holders

As of February 22, 2008, there were 546 record holders and approximately 7,650 beneficial owners (held in street name) of our common stock.

Performance Graph

The following graph compares our five-year cumulative total shareholder return (assuming reinvestment of dividends) with the cumulative total return of the Standard & Poor's Oil and Gas Exploration & Production 600 Index and the Standard & Poor's SmallCap 600 Index. There are six companies in the Standard & Poor's Oil and Gas Exploration & Production 600 Index: Cabot Oil & Gas Corporation, Penn Virginia Corporation, Petroleum Development Corporation, St. Mary Land & Exploration Company, Stone Energy Corporation and Swift Energy Company. The graph assumes $100 is invested on January 1, 2003 in us and each index at December 31, 2002 closing prices.

Comparison of Five-Year Cumulative Total Return
Penn Virginia Corporation, S&P SmallCap 600 Index and
S&P Exploration & Production 600 Index



	2003	2004	2005	2006	2007
Penn Virginia Corporation	156.35	230.98	329.77	404.94	507.38
S&P SmallCap 600 Index	138.79	170.22	183.30	211.01	210.38
S&P Oil & Gas Exploration & Production 600 Index	138.85	211.55	354.09	357.30	452.48

Item 6 ***Selected Financial Data***

The following selected historical financial information was derived from our audited consolidated financial statements as of December 31, 2007, 2006, 2005, 2004 and 2003, and for each of the years then ended. The selected financial data should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data."

	Year Ended December 31,				
	2007	2006	2005 (4)	2004	2003
	(in thousands, except share data)				
Revenues	$ 852,950	$ 753,929	$ 673,864	$ 228,425	$ 181,284
Operating income (1)	$ 192,624	$ 170,532	$ 162,017	$ 80,796	$ 62,101
Net income	$ 50,754	$ 75,909	$ 62,088	$ 33,355	$ 28,522
Per common share: (2)					
Net income, basic	$ 1.33	$ 2.03	$ 1.67	$ 0.91	$ 0.80
Net income, diluted	$ 1.32	$ 2.01	$ 1.66	$ 0.91	$ 0.79
Dividends paid	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23
Cash flows provided by operating activities	$ 313,030	$ 275,819	$ 231,407	$ 146,365	$ 109,704
Total assets	$ 2,253,461	$ 1,633,149	$ 1,251,546	$ 783,335	$ 683,733
Long-term debt, net of current portion	$ 751,153	$ 428,214	$ 325,846	$ 188,926	$ 154,286
Minority interest in PVG (3)	$ 179,162	$ 438,372	$ 313,524	$ 182,891	$ 190,508
Shareholders' equity (3)	$ 810,098	$ 382,425	$ 310,308	$ 252,860	$ 211,648

(1) Operating income in 2004 included a $7.5 million loss on assets held for sale. Operating income in 2007, 2006, 2005, 2004 and 2003 included impairment charges of $2.5 million, $8.5 million, $4.8 million, $0.7 million and $0.4 million related to our oil and gas properties.

(2) For comparative purposes, amounts per common share in 2003 have been adjusted for the effect of a two-for-one stock split on June 10, 2004 and amounts per common share in 2006, 2005, 2004 and 2003 have been adjusted for the effect of a two-for-one stock split on June 19, 2007.

(3) The decrease in minority interest and consequent increase in shareholders' equity is primarily due to the gain on the sale of PVG and PVR units. We recognized a gain in paid-in capital of $104.1 million in May 2007 when all junior securities of PVG or PVR ceased to be outstanding. See Note 6, "Gain on Sale of Subsidiary Units" in the Notes to the Consolidated Financial Statements.

(4) The 2005 column includes the results of operations of our natural gas midstream segment since March 3, 2005, the closing date of the acquisition of Cantera.

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

The following discussion and analysis of the financial condition and results of operations of Penn Virginia Corporation and its subsidiaries should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 8, "Financial Statements and Supplementary Data." Our discussion and analysis include the following items:

- Overview of Business
- Acquisitions, Dispositions and Investments
- Liquidity and Capital Resources
- Contractual Obligations
- Off-Balance Sheet Arrangements
- Results of Operations
- Summary of Critical Accounting Policies and Estimates
- Environmental Matters
- Recent Accounting Pronouncements
- Forward-Looking Statements

Overview of Business

We are an independent oil and gas company primarily engaged in the exploration, development and production of natural gas and oil in various onshore U.S. regions including East Texas, the Mid-Continent, Appalachia, Mississippi and the Gulf Coast. We also indirectly own partner interests in PVR, a publicly traded limited partnership which is engaged in the coal and natural resource management and natural gas midstream businesses. Our ownership interests in PVR are held principally through our general partner interest and our 82% limited partner interest in PVG, a publicly traded limited partnership. PVG owns 100% of the general partner of PVR, which holds a 2% general partner interest in PVR, and an approximately 42% limited partner interest in PVR.

We are engaged in three primary business segments: (1) oil and gas, (2) coal and natural resource management and (3) natural gas midstream. We operate our oil and gas segment. PVR operates our coal and natural resource management and natural gas midstream segments and is consolidated by PVG. We consolidate PVG's results into our financial statements. In 2007, we had an approximately 82% interest in PVG's net income. Our operating income was $192.6 million in 2007, compared to $170.5 million in 2006 and $162.0 million in 2005. In 2007, the oil and gas segment contributed $104.0 million, or 54%, to operating income, the PVR coal and natural resource management segment contributed $69.0 million, or 36%, to operating income, and the PVR natural gas midstream segment contributed $48.9 million, or 25%, to operating income. Corporate and other functions resulted in $29.3 million of operating expenses. The following table presents a summary of certain financial information relating to our segments:

	Oil and Gas	PVR Coal and Natural Resource Management	PVR Natural Gas Midstream	Corporate and Other	Consolidated
			(in thousands)		
For the Year Ended December 31, 2007:					
Revenues	$ 303,241	$ 111,639	$ 437,806	$ 264	$ 852,950
Operating costs and expenses	109,449	20,138	370,070	28,560	528,217
Impairment of oil and gas properties	2,586	-	-	-	2,586
Depreciation, depletion and amortization	87,223	22,463	18,822	1,015	129,523
Operating income (loss)	$ 103,983	$ 69,038	$ 48,914	$ (29,311)	$ 192,624
For the Year Ended December 31, 2006:					
Revenues	$ 235,956	$ 112,981	$ 404,910	$ 82	$ 753,929
Operating costs and expenses	86,369	19,138	358,440	16,716	480,663
Impairment of oil and gas properties	8,517	-	-	-	8,517
Depreciation, depletion and amortization	56,237	20,399	17,094	487	94,217
Operating income (loss)	$ 84,833	$ 73,444	$ 29,376	$ (17,121)	$ 170,532
For the Year Ended December 31, 2005:					
Revenues	$ 226,819	$ 95,755	$ 350,593	$ 697	$ 673,864
Operating costs and expenses	80,669	16,121	321,509	11,826	430,125
Impairment of oil and gas properties	4,785	-	-	-	4,785
Depreciation, depletion and amortization	45,885	17,890	12,738	424	76,937
Operating income (loss)	$ 95,480	$ 61,744	$ 16,346	$ (11,553)	$ 162,017

Oil and Gas Segment

We have a geographically diverse asset base with core areas of operation in East Texas, the Mid-Continent, Appalachia, Mississippi and the South Louisiana and South Texas Gulf Coast regions of the United States. As of December 31, 2007, we had proved natural gas and oil reserves of approximately 680 Bcfe, of which 87% were natural gas and 59% were proved developed. As of December 31, 2007, 95% of our proved reserves were located in primarily longer-lived, lower-risk basins in East Texas, the Mid-Continent, Appalachia and Mississippi. Wells in these regions are generally characterized by predictable production profiles. Our Gulf Coast properties, representing 5% of proved reserves, are shorter-lived and have higher impact drilling prospects that provide a complementary counterbalance to our longer-lived assets. In 2007, we produced 40.6 Bcfe, a 30% increase compared to 31.3 Bcfe in 2006. As of December 31, 2007, we operated approximately 95% of the net wells in which we held a working interest. In the three years ended December 31, 2007, we drilled 677 gross (507.0 net) wells, of which 95% were successful in producing natural gas in commercial quantities.

We have grown our reserves and production primarily through development and exploratory drilling, complemented by strategic acquisitions. In 2007, we added 255 Bcfe of proved reserves, 71% of which was added through the drillbit, for a total reserve replacement rate of 628% of production. In 2007, capital expenditures in our oil and gas segment were $520.4 million, of which $333.2 million, or 64%, was related to development drilling and facilities, $141.9 million, or 27%, was related to acquisitions and $45.3 million, or 8%, was related to exploratory activity. During 2007, we acquired properties with 74.4 Bcfe of proved reserves and sold properties with 21.5 Bcfe of proved reserves. For a more detailed discussion of our acquisitions, see "—Acquisitions, Dispositions and Investments."

As of December 31, 2007, we owned 1.3 million net acres of leasehold interests, approximately 48% of which were undeveloped. We have identified approximately 571 proved undeveloped locations and over 1,500 additional potential drilling locations, of which more than half are located in the Cotton Valley play in East Texas and the Mid-Continent. Many of our proved undeveloped locations and additional potential drilling locations are direct offsets or extensions from existing production. We believe our existing undeveloped acreage position represents approximately ten years of drilling opportunities based on our current drilling rate. We believe our recent property acquisitions provide additional opportunities for identifying new locations.

Our operations include both conventional and unconventional developmental drilling opportunities, as well as some exploratory prospects. In the Cotton Valley play in East Texas, we drilled 120 gross wells in 2007 and added a sixth drilling rig in the second half of 2007. We are shifting focus to infill drilling on 20-acre spacing, which may increase proved reserves and production levels. In Appalachia, we drilled 41 gross wells in 2007, including 27 gross horizontal coalbed methane locations. In the Selma Chalk play in Mississippi, we drilled 73 gross wells in 2007, including two successful horizontal wells. We also have unconventional development programs in the Mid-Continent and some higher-impact exploratory prospects in the Gulf Coast.

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.

PVR Coal and Natural Resource Management Segment

As of December 31, 2007, PVR owned or controlled approximately 818 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. As of December 31, 2007, approximately 89% of PVR's proven and probable coal reserves were "steam" coal used primarily by electric generation utilities, and the remaining 11% were metallurgical coal used primarily by steel manufacturers. PVR enters into long-term leases with experienced, third-party mine operators, providing them the right to mine its coal reserves in exchange for royalty payments. PVR actively works with its lessees to develop efficient methods to exploit its reserves and to maximize production from its properties. PVR does not operate any mines. In 2007, PVR's lessees produced 32.5 million tons of coal from its properties and paid PVR coal royalties revenues of $94.1 million, for an average royalty per ton of $2.89. Approximately 81% of PVR's coal royalties revenues in 2007 and 84% of PVR's coal royalties revenues in 2006 were derived from coal mined on its properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price. The balance of PVR's coal royalties revenues for the respective periods was derived from coal mined on its properties under leases containing fixed royalty rates that escalate annually. In 2007, five lessees accounted for 65% of PVR's coal royalties revenues and 7% of our total consolidated revenues.

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. New legislation or regulations have been or 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 lessee's customers to change operations significantly or incur substantial costs. See Item 1A, "Risk Factors." To a lesser extent, coal prices also impact coal royalties revenues. Generally, as coal prices change, PVR's average royalty per ton also changes because the majority of PVR's lessees pay royalties based on the gross sales prices of the coal mined. Most of PVR's coal is sold by its lessees under contracts with a duration of one year or more; therefore, changes to PVR's average royalty occur as its lessees' contracts are renegotiated. Coal prices, especially in Central Appalachia where the majority of PVR's coal is produced, increased significantly from the beginning of 2004 through most of 2006. The price increase during that period was primarily the result of increased electricity demand, rebuilding of inventories and decreasing coal production in Central Appalachia. In the second half of 2006 and continuing into 2007, coal prices decreased from the historically high levels experienced in the previous two and one half years, due to higher than normal coal inventories at electric utilities and milder than normal winter weather. Coal prices increased significantly in the fourth quarter of 2007 after remaining nearly stagnant since late 2006. The global markets for most types of coal remain strong. Continued demand from emerging countries and the increased consumption domestically have created a strong global picture. U.S.-produced coal enjoyed increased demand abroad during 2007 as dwindling supplies and the decline of the dollar made U.S.-exported coal more attractive. Pricing appears strong heading into 2008 primarily due to increasing global demand and supply difficulties.

PVR also earns revenues from the provision of fee-based coal preparation and loading services, from the sale of standing timber on its properties, from oil and gas royalty interests it owns and from coal transportation, or wheelage, fees.

PVR's management continues to focus on acquisitions that increase and diversify its sources of cash flow. During 2007, PVR acquired 60 million tons of coal reserves in two acquisitions for an aggregate purchase price of approximately $52 million. In addition, in 2007, PVR acquired approximately 62,000 acres of forestland in West Virginia for a purchase price of approximately $93 million to expand its existing timber business. In 2007, PVR also acquired royalty interests in certain oil and gas leases relating to properties located in Kentucky and Virginia for a purchase price of approximately $31 million to expand its existing oil and gas royalty interest business. For a more detailed discussion of PVR's acquisitions, see "—Acquisitions, Dispositions and Investments."

PVR Natural Gas Midstream Segment

PVR owns and operates natural gas midstream assets located in Oklahoma and the panhandle of Texas. These assets include approximately 3,682 miles of natural gas gathering pipelines and three natural gas processing facilities having 160 MMcfd of total capacity. PVR's natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. PVR also owns a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines. PVR acquired its first natural gas midstream assets through the acquisition of Cantera in March 2005.

In 2007, system throughput volumes at PVR's gas processing plants and gathering systems, including gathering-only volumes, were 67.8 Bcf, or approximately 186 MMcfd. In 2007, three of PVR's natural gas midstream customers accounted for 53% of PVR's natural gas midstream revenues and 27% of our total consolidated revenues.

Revenues, profitability and the future rate of growth of the PVR natural gas midstream segment are highly dependent on market demand and prevailing NGL and natural gas prices. Historically, changes in the prices of most NGL products have 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.

PVR continually seeks new supplies of natural gas to both offset the natural declines in production from the wells currently connected to its systems and to increase system throughput volumes. 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 contracting for natural gas that has been released from competitors' systems. During 2007, PVR expended $38.7 million on expansion projects to allow it to capitalize on such opportunities. The expansion projects include two natural gas processing facilities with a combined 140 MMcfd of inlet gas capacity.

Corporate and Other

Corporate and other primarily represents corporate functions.

Ownership of and Relationship with PVG and PVR

As of December 31, 2007, we owned the general partner of PVG and an approximately 82% limited partner interest in PVG. PVG owns the general partner of PVR, which holds a 2% general partner interest in PVR and all the incentive distribution rights, and an approximately 42% limited interest in PVR. We directly owned an additional 0.5% limited partner interest in PVR as of December 31, 2007. The diagram in Item 1, "Business—Corporate Structure" depicts our ownership of PVG and PVR as of December 31, 2007.

Penn Virginia, PVG and PVR are publicly traded on the New York Stock Exchange under the symbols "PVA," "PVG" and "PVR." Because we control the general partner of PVG, the financial results of PVG are included in our consolidated financial statements. Because PVG controls the general partner of PVR, the financial results of PVR are included in PVG's condensed consolidated financial statements. However, PVG and PVR function with capital structures that are independent of each other and us, with each having publicly traded common units and PVR having its own debt instruments. PVG does not currently have any debt instruments. While we report consolidated financial results of PVR's coal and natural resources management and natural gas midstream businesses, the only cash we received from those businesses is in the form of cash distributions from PVG.

We are currently entitled to receive quarterly cash distributions from PVG and PVR on our limited partner interests in PVG and PVR. We have historically received increasing distributions from our partner interests in PVG and PVR. As a result of our partner interests in PVG and PVR, we received total distributions from PVG and PVR in 2007, 2006 and 2005 as shown in the following table:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Penn Virginia GP Holdings, L.P.	$29,200	$ —	$ —
Penn Virginia Resource Partners, L.P.	398	28,326	21,212
Total	$29,598	$28,326	$21,212

Based on PVG's and PVR's current annualized distribution rates of $1.28 and $1.76 per unit, we would receive aggregate annualized distributions of $41.5 million in respect of our partner interests.

Acquisitions, Dispositions and Investments

Oil and Gas Segment

In October 2007, we acquired lease rights to property covering 4,800 acres located in east Texas, with estimated proved reserves of 21.9 Bcfe. The purchase price was $44.9 million in cash and was funded with long-term debt under our revolving credit facility.

In October 2007, we sold to PVR oil and gas royalty interests associated with leases of property in eastern Kentucky and southwestern Virginia with estimated proved reserves of 8.7 Bcfe at January 1, 2007. The sale price was $31.0 million in cash, and the proceeds of the sale were used to repay borrowings under our revolving credit facility. The gain on the sale and the related depletion expenses have been eliminated in the consolidation of our financial statements.

In September 2007, we sold non-operated working interests in oil and gas properties located in eastern Kentucky and southwestern Virginia, with estimated proved reserves of 13.3 Bcfe. The sale price was $29.1 million in cash, and the proceeds of the sale were used to repay borrowings under our revolving credit facility. We recognized a gain of $12.4 million on the sale, which is reported in the revenues section of our consolidated statements of income.

In August 2007, we acquired lease rights to property covering approximately 22,700 acres located in eastern Oklahoma, with estimated proved reserves of 18.8 Bcfe. The purchase price was $47.9 million in cash and was funded with long-term debt under our revolving credit facility.

In July 2007, we acquired lease rights to property covering approximately 4,000 acres located in east Texas, with estimated proved reserves of 19.5 Bcfe. The purchase price was $22.0 million in cash and was funded with long-term debt under our revolving credit facility.

In June 2006, we acquired 100% of the capital stock of Crow Creek Holding Corporation, or Crow Creek. Crow Creek was a privately owned independent exploration and production company with operations primarily in the Oklahoma portions of the Arkoma and Anadarko Basins. Crow Creek's assets included estimated net proved reserves of 42.7 Bcfe, approximately 85% of which were natural gas. The purchase price was $71.5 million in cash and was funded with long-term debt under our revolving credit facility.

PVR Coal and Natural Resource Management Segment

In October 2007, PVR purchased from us oil and gas royalty interests associated with leases of property in eastern Kentucky and southwestern Virginia and with estimated proved reserves of 8.7 Bcfe at January 1, 2007. The purchase price was $31.0 million in cash and was funded with long-term debt under PVR's revolving credit facility. The effects of the $31.0 million purchase were eliminated in the consolidation of our financial statements.

In September 2007, PVR acquired fee ownership of approximately 62,000 acres of forestland in northern West Virginia. The purchase price was $93.3 million in cash and was funded with long-term debt under PVR's revolving credit facility.

In June 2007, PVR acquired a combination of fee ownership and lease rights to approximately 51 million tons of coal reserves, along with a preparation plant and coal handling facilities. The property is located on approximately 17,000 acres in western Kentucky. The purchase price was $42.0 million in cash and was funded with long-term debt under PVR's revolving credit facility.

In May 2006, PVR acquired lease rights to approximately 69 million tons of coal reserves. The reserves are located on approximately 20,000 acres in southern West Virginia. The purchase price was $65.0 million and was funded with long-term debt under PVR's revolving credit facility.

In July 2005, PVR acquired fee ownership of approximately 94 million tons of coal reserves. The reserves are located along the Green River in the western Kentucky portion of the Illinois Basin. The purchase price was $62.4 million in cash and the assumption of $3.3 million of deferred income and was funded with long-term debt under PVR's revolving credit facility.

PVR Natural Gas Midstream Segment

PVR is currently constructing an 80 MMcfd gas processing plant and related pipelines (the Crossroads System) in east Texas. The processing plant is expected to be placed into service by April 2008. The processing plant will provide fee-based gas processing services to our oil and gas business, as well as other producers. The plant and related facilities are expected to cost approximately $22 million and are being funded with long-term debt under PVR's revolving credit facility.

In June 2006, PVR completed the acquisition of approximately 115 miles of gathering pipelines and related compression facilities in Texas and Oklahoma. These assets are contiguous to PVR's Beaver/Perryton System. The purchase price was $14.7 million and was funded with cash. Subsequently, PVR borrowed $14.7 million under its revolving credit facility to replenish the cash used for the acquisition.

In March 2005, PVR completed its acquisition of Cantera, a natural gas midstream gas gathering and processing company with primary locations in the Mid-Continent area of Oklahoma and the panhandle of Texas. Cash paid in connection with the acquisition was $199.2 million, net of cash received and including capitalized acquisition costs, which we funded with a $110 million term loan and with long-term debt under its revolving credit facility. PVR used the proceeds from our sale of common units in a subsequent public offering in March 2005 to repay the term loan in full and to reduce outstanding indebtedness under its revolving credit facility. See Note 3 in the Notes to Consolidated Financial Statements for pro forma financial information.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, Penn Virginia, PVG and PVR operate with independent capital structures. Since PVR's inception in 2001 and PVG's inception in 2006, with the exception of cash distributions paid to us by PVG and 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 PVG and PVR units. We expect that our cash needs and the cash needs of PVG and PVR will continue to be met independently of each other with a combination of these funding sources.

Cash Flows

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

The following table summarizes our cash flow statements for the years ended December 31, 2007 and 2006, consolidating our segments:

For the Year Ended December 31, 2007	Oil and Gas & Corporate	PVR Coal and PVR Midstream	Consolidated
Net cash provided by operating activities	$ 185,206	$ 127,824	$ 313,030
Cash flows from financing activities:			
Dividends paid	(8,499)	-	(8,499)
PVR distributions received (paid)	39,910	(89,649)	(49,739)
Debt borrowings (repayments), net	131,000	193,500	324,500
Gross proceeds from PVA stock offering	135,441	-	135,441
Cash received for stock warrants sold	18,187	-	18,187
Cash paid for convertible note hedges	(36,817)	-	(36,817)
Other	972	597	1,569
Net cash provided by financing activities	280,194	104,448	384,642
Net cash provided by operating and financing activities	465,400	232,272	697,672
Net cash used in investing activities	(459,301)	(224,182)	(683,483)
Net increase in cash and cash equivalents	$ 6,099	$ 8,090	$ 14,189

For the Year Ended December 31, 2006	Oil and Gas & Corporate	PVR Coal and PVR Midstream	Consolidated
Net cash provided by operating activities	$ 168,475	$ 107,344	$ 275,819
Cash flows from financing activities:			
Dividends paid	(8,398)	-	(8,398)
PVR distributions received (paid)	28,327	(66,954)	(38,627)
Debt borrowings (repayments), net	142,000	(37,100)	104,900
Proceeds from equity issuance	2,810	115,008	117,818
Other	5,623	(375)	5,248
Net cash provided by financing activities	170,362	10,579	180,941
Net cash provided by operating and financing activities	338,837	117,923	456,760
Net cash used in investing activities	(332,659)	(129,676)	(462,335)
Net increase (decrease) in cash and cash equivalents	$ 6,178	$ (11,753)	$ (5,575)

Cash provided by operating activities of the oil and gas segment and corporate increased by $16.7 million, or 10%, from $168.5 million in 2006 to $185.2 million in 2007. The overall increase in cash provided by operating activities in 2007 compared to 2006 was primarily attributable to increased natural gas and crude oil production, partially offset by increased consulting fees and staffing costs. Cash provided by operating activities of the oil and gas segment and corporate increased by $30.8 million, or 22%, from $137.7 million in 2005 to $168.5 million in 2006. The overall increase in cash provided by operating activities in 2006 compared to 2005 was primarily attributable to increased natural gas and crude oil production.

Cash provided by operating activities in the PVR coal and natural resource management and PVR natural gas midstream segments increased by $20.5 million, or 20%, from $107.3 million in 2006 to $127.8 million in 2007. The overall increase in cash provided by operating activities in 2007 compared to 2006 was primarily attributable to the increase in the PVR natural gas midstream segment's operating income, partially offset by increased cash outflows for derivative settlements. Cash provided by operating activities in the PVR coal and natural resource management and PVR natural gas midstream segments increased by $13.6 million, or 15%, from $93.7 million in 2005 to $107.3 million in 2006. The overall increase in cash provided by operating activities in 2006 compared to 2005 was primarily attributable to a higher average coal royalty per ton and cash flows from PVR's natural gas midstream business, which was acquired in March 2005, partially offset by increased cash outflows for derivative settlements.

Capital Expenditures

Capital expenditures, which comprise the primary portion of cash used in investing activities, totaled $753.3 million in 2007, compared to $472.0 million in 2006. The following table sets forth capital expenditures by segment during the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Oil and gas			
Proved property acquisitions	$ 88,174	$ 72,724	$ -
Development drilling	310,428	175,257	107,744
Exploration drilling	42,540	41,923	18,562
Seismic	2,773	6,238	7,836
Lease acquisition and other (1)	53,775	27,795	30,297
Pipeline, gathering, facilities	22,738	14,547	5,138
Total	520,428	338,484	169,577
Coal and natural resource management			
Acquisitions (2)	145,918	75,182	92,093
Expansion capital expenditures	85	15,103	5,657
Other property and equipment expenditures	84	100	351
Total	146,087	90,385	98,101
Natural gas midstream			
Acquisitions, net of cash acquired	-	14,626	199,223
Expansion capital expenditures	38,686	15,394	3,324
Other property and equipment expenditures	9,767	9,414	4,264
Total	48,453	39,434	206,811
Other	7,294	3,682	350
Total capital expenditures	$ 722,262	$ 471,985	$ 474,839

(1) Amount in 2006 excludes deferred tax assets of $32.3 million and acquisition of net liabilities other than property or equipment of $29.1 million related to the acquisition of Crow Creek.

(2) Amount in 2007 includes an $11.5 million lease receivable associated with the acquisition of fee ownership and lease rights to coal reserves in western Kentucky. Amount in 2007 excludes $31 million of royalty interests that PVR purchased from us. Amount in 2006 excludes the acquisition of assets and liabilities other than property or equipment of $1.2 million. Amount in 2005 excludes $10.4 million of equity issued and $0.7 million of liabilities assumed in connection with the acquisition of coal reserves in eastern Kentucky. Amount in 2005 also excludes $3.3 million of deferred income assumed in connection with the acquisition of coal reserves in western Kentucky.

In 2007, the oil and gas segment made aggregate capital expenditures of $520.4 million primarily for development drilling, proved property acquisitions and lease acquisitions. In September 2007, we sold non-operated working interests in oil and gas properties located in eastern Kentucky and southwestern Virginia for $29.1 million in cash. In 2006, the oil and gas segment made aggregate capital expenditures of $338.5 million primarily for development drilling, proved property acquisitions and exploratory drilling. In 2005, the oil and gas segment made aggregate capital expenditures of $169.6 million primarily for development drilling, lease acquisitions and exploratory drilling.

In 2007, PVR made aggregate capital expenditures of $225.5 million primarily for coal reserve acquisitions, a forestland acquisition, an oil and gas royalty interest acquisition and natural gas midstream gathering system expansion projects. In 2006, PVR made aggregate capital expenditures of $129.8 million primarily for coal reserve acquisitions, coal loadout facility construction projects, a natural gas midstream acquisition and natural gas midstream gathering system expansion projects. In 2005, PVR made aggregate capital expenditures of $304.9 million primarily for the acquisition of its natural gas midstream business and coal reserve acquisitions. Other investments in 2005 included a $4.1 million purchase of railcars that PVR previously leased and $4.4 million of natural gas gathering system additions.

We funded oil and gas and other capital expenditures in 2007 with borrowings under our revolving credit facility, cash provided by operating activities, the issuance of common stock and convertible notes and proceeds from the sales of oil and gas working and royalty interests. We funded oil and gas and other capital expenditures in 2006 with cash provided by operating activities and borrowings under our revolving credit facility. We funded oil and gas and other capital expenditures in 2005 with cash provided by operating activities and borrowings under our revolving credit facility. Borrowings under our revolving credit facility and cash provided by operating activities funded our capital expenditures in 2005.

PVR funded capital expenditures in 2007 with cash provided by operating activities and borrowings under its revolving credit facility. PVR funded capital expenditures in 2006 with cash provided by operating activities, borrowings under its revolving credit facility, proceeds from the sale of common and Class B units to PVG and a contribution from its general partner to maintain its 2% general partner interest. PVR funded capital expenditures in 2005 with cash provided by operating activities, borrowings under its revolving credit facility, proceeds from its secondary public offering of common units and a contribution from its general partner to maintain its 2% general partner interest in PVR.

We had $131.0 million of net borrowings, comprised of repayments of $99.0 million under our revolving credit facility and borrowings of $230.0 million under our convertible senior subordinated notes.in 2007. This is compared to net borrowings of $142.0 million under our revolving credit facility in 2006. As a result of our partner interests in PVG and PVR, we received cash distributions of $29.6 million in 2007, compared to $28.3 million of cash distributions in 2006 and $21.2 million of cash distributions in 2005. Funds from both of these sources were primarily used for capital expenditures. In addition, proceeds from the sales of our oil and gas working interests in 2007 were used to repay borrowings under our revolving credit facility.

PVR had $193.5 of net borrowings in 2007, comprised of net borrowings of $204.5 million under the PVR revolving credit facility and net repayments of $11.0 million under the PVR senior unsecured notes. This is compared to $37.1 million of net repayments in 2006, comprised of net repayments of $28.8 million under the PVR revolving credit facility and net repayments of $8.3 million under the PVR senior unsecured notes. Funds from the borrowings in 2007 and 2006 were primarily used for capital expenditures.

In January 2008, PVG declared a $0.32 per unit quarterly distribution for the three months ended December 31, 2007, or $1.28 per unit on an annualized basis, of which we will receive $10.3 million, or $41.2 million on an annualized basis, as a result of our limited partner interest in PVG. This distribution was paid on February 19, 2008 to unitholders of record at the close of business on February 4, 2008. The portion of PVR's distribution paid to PVG serves as the basis for PVG's distribution to its unitholders, including us.

Long-Term Debt

Revolving Credit Facility. As of December 31, 2007, we had $122.0 million outstanding under our $479 million revolving credit facility, or the Revolver, that matures in December 2010. The Revolver is secured by a portion of our proved oil and gas reserves. The Revolver is available to us for general purposes, including working capital, capital expenditures and acquisitions, and includes a $20 million sublimit for the issuance of letters of credit. We had outstanding letters of credit of $0.3 million as of December 31, 2007. Effective with the closing of our offering of convertible senior subordinated notes on December 5, 2007, the commitments and borrowing base under the Revolver automatically decreased from $525 million to $479 million. At the current $479 million limit on the Revolver, and given our outstanding balance of $122.0 million, net of $0.3 million of letters of credit, we could borrow up to $356.6 million. In 2007, we incurred commitment fees of $0.2 million on the unused portion of the Revolver. We capitalized $3.7 million of interest cost incurred in 2007. The Revolver is governed by a borrowing base calculation. Our borrowing base is currently $479 million and is redetermined semi-annually. We have the option to elect interest at (i) the London Inter Bank Offering Rate, or the LIBOR, plus a Eurodollar margin ranging from 1.00% to 1.75%, based on the ratio of our outstanding borrowings to the borrowing base or (ii) the greater of the prime rate or federal funds rate plus a margin of up to 0.50%. The weighted average interest rate on borrowings outstanding under the Revolver during 2007 was 6.7%.

The financial covenants under the Revolver require us to not exceed specified debt-to-EBITDAX (as defined in the Revolver) and EBITDAX-to-interest expense ratios 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 December 31, 2007, we were in compliance with all of our covenants under the Revolver.

Convertible Senior Subordinated Notes. As of December 31, 2007, we had $230.0 million of convertible senior subordinated notes, or the Convertible Notes, outstanding. The Convertible Notes bear interest at a rate of 4.50% per year payable semiannually in arrears on May 15 and November 15 of each year, beginning on May 15, 2008.

The Convertible Notes are convertible into cash up to the principal amount thereof and shares of our common stock, if any, in respect of the excess conversion value, based on an initial conversion rate of 17.3160 shares of common stock per $1,000 principal amount of the Convertible Notes (which is equal to an initial conversion price of approximately $57.75 per share of common stock), subject to adjustment, and, if not converted or repurchased earlier, will mature on November 15, 2012. Holders of Convertible Notes may convert their Convertible Notes at their option prior to the close of business on the business day immediately preceding September 15, 2012 only under the following circumstances: (1) during any fiscal quarter beginning after December 31, 2007 (and only during such fiscal quarter), if the last reported sale price per share of common stock for at least 20 trading days (whether or not consecutive) in the 30 consecutive trading days ending on the last trading day of the immediately preceding fiscal quarter is greater than or equal to 130% of the then applicable conversion price on each such trading day; (2) during the five business day period after any ten consecutive trading day period in which the trading price per $1,000 principal amount of the Convertible Notes for each day of such period was less than 98% of the product of the last reported sale price per share of common stock and the then applicable conversion rate on each such day; or (3) upon the occurrence of certain corporate events set forth in the indenture governing the Convertible Notes. On and after September 15, 2012 until the close of business on the third business day immediately preceding November 15, 2012, holders of the Convertible Notes may convert their Convertible Notes at any time, regardless of the foregoing circumstances.

The holders of the Convertible Notes who convert their Convertible Notes in connection with a make-whole fundamental change, as defined in the indenture governing the Convertible Notes, may be entitled to an increase in the conversion rate as specified in the indenture governing the Convertible Notes. Additionally, in the event of a fundamental change, as defined in the indenture governing the Convertible Notes, the holders of the Convertible Notes may require us to purchase all or a portion of their Convertible Notes at a purchase price equal to 100% of the principal amount of the Convertible Notes, plus accrued and unpaid interest, if any.

The Convertible Notes are our unsecured senior subordinated obligations, ranking junior in right of payment to any of our senior indebtedness and to any of our secured indebtedness to the extent of the value of the assets securing such indebtedness and equal in right of payment to any of our future unsecured senior subordinated indebtedness. The Convertible Notes will rank senior in right of payment to any of our future junior subordinated indebtedness and will structurally rank junior to all existing and future indebtedness of our subsidiaries.

Credit Facility. We have a credit facility with a financial institution, which had no borrowings against it as of December 31, 2007. The facility is effective through August 31, 2008 and is renewable annually. The facility consists of a working capital facility in the amount of $10 million. An additional $10 million facility is available upon bank approval. The interest rate on the working capital facility is equal to the LIBOR plus 1.00% and the interest rate on the additional facility is equal to the LIBOR plus an applicable margin ranging from 1.00% to 1.50%.

Interest Rate Swaps. We have entered into interest rate swap agreements, or the Revolver Swaps, to establish fixed rates on a portion of the outstanding borrowings under the Revolver until December 2010. The notional amounts of the Revolver Swaps total $50 million. We will pay a weighted average fixed rate of 5.34% on the notional amount, and the counterparties will pay a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings in interest expense. After considering the applicable margin of 1.00% in effect as of December 31, 2007, the total interest rate on the $50 million portion of Revolver borrowings covered by the Revolver Swaps was 6.34% at December 31, 2007.

PVR Revolving Credit Facility. As of December 31, 2007, PVR had $347.7 million outstanding under its unsecured $450 million revolving credit facility, or the PVR Revolver, that matures in December 2011. The PVR Revolver is available to PVR for general purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. PVR had outstanding letters of credit of $1.6 million as of December 31, 2007. At the current $450 million limit on the PVR Revolver, and given the outstanding balance of $347.7 million, net of $1.6 million of letters of credit, PVR could borrow up to $100.7 million. In 2007, PVR incurred commitment fees of $0.3 million on the unused portion of the PVR Revolver. The interest rate under the PVR Revolver fluctuates based on the ratio of PVR's total indebtedness-to-EBITDA. Interest is payable at a base rate plus an applicable margin of up to 0.75% if PVR selects the base rate borrowing option under the PVR Revolver or at a rate derived from the LIBOR plus an applicable margin ranging from 0.75% to 1.75% if PVR selects the LIBOR-based borrowing option. The weighted average interest rate on borrowings outstanding under the PVR Revolver during 2007 was 6.2%.

The financial covenants under the PVR Revolver require PVR not to exceed specified debt-to-consolidated EBITDA and consolidated EBITDA-to-interest expense ratios. The PVR Revolver prohibits PVR from making distributions to its partners if any potential default, or event of default, as defined in the PVR Revolver, occurs or would result from the 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 its business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. As of December 31, 2007, PVR was in compliance with all of its covenants under the PVR Revolver.

PVR Senior Unsecured Notes. As of December 31, 2007, PVR owed $64.0 million under its senior unsecured notes, or the PVR Notes. The PVR Notes bear interest at a fixed rate of 6.02% and mature in March 2013, with semi-annual principal and interest payments. The PVR Notes are equal in right of payment with all of PVR's other unsecured indebtedness, including the PVR Revolver. The PVR Notes require PVR to obtain an annual confirmation of its credit rating, with a 1.00% increase in the interest rate payable on the PVR Notes in the event that its credit rating falls below investment grade. In March 2007, PVR's investment grade credit rating was confirmed by Dominion Bond Rating Services. The PVR Notes contain various covenants similar to those contained in the PVR Revolver. As of December 31, 2007, PVR was in compliance with all of its covenants under the PVR Notes.

PVR Interest Rate Swaps. PVR has entered into interest rate swap agreements, or the PVR Revolver Swaps, to establish fixed rates on a portion of the outstanding borrowings under the PVR Revolver. Until March 2010, the notional amounts of the PVR Revolver Swaps total $160 million. From March 2010 to December 2011, the notional amounts of the PVR Revolver Swaps total $100 million. Until March 2010, PVR will pay a weighted average fixed rate of 4.33% on the notional amount, and the counterparties will pay a variable rate equal to the three-month LIBOR. From March 2010 to December 2011, PVR will pay a weighted average fixed rate of 4.40% on the notional amount, and the counterparties will 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% in effect as of December 31, 2007, the total interest rate on the $160 million portion of PVR Revolver borrowings covered by the PVR Revolver Swaps was 5.58% at December 31, 2007.

Future Capital Needs and Commitments

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, East Texas and the Mid-Continent with relatively moderate risk, potentially higher return development projects and exploration prospects in south Texas and south Louisiana. We expect to continue to execute a program dominated by relatively low risk, moderate return development drilling and, to a lesser extent, higher risk, higher return exploration drilling, supplemented periodically with acquisitions.

We have budgeted oil and gas segment capital expenditures of $474.8 million in 2008. These expenditures are expected to be funded primarily by operating cash flow, cash distributions received from PVG and PVR and from the Revolver as needed. 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 operating activities and sources of debt financing are sufficient to fund our 2008 planned oil and gas capital expenditure program.

We believe our portfolio of assets provides us with opportunities for organic growth in 2008 which will require capital in excess of our internal sources. We expect to continue to rely on the Revolver to fund a large portion of our capital needs, supplemented by the issuance of additional debt and equity securities as needed.

Currently, PVG has no capital requirements. In the future, we may decide to facilitate PVR acquisitions by providing additional debt or equity to PVR.

Part of PVR's strategy is to make acquisitions and other capital expenditures which increase cash available for distribution to its unitholders. PVR's ability to make these acquisitions in the future will depend in part on the availability of debt financing and on its ability to periodically use equity financing through the issuance of new common units, which will depend on various factors, including prevailing market conditions, interest rates and its financial condition and credit rating at the time. In 2008, PVR anticipates making capital expenditures, excluding acquisitions, of approximately $23 million, including approximately $21 million for natural gas midstream system expansion projects and maintenance capital expenditures and approximately $2 million for coal services projects and other property and equipment. PVR intends to fund these capital expenditures with a combination of cash flows provided by operating activities and borrowings under the PVR Revolver. PVR makes quarterly cash distributions of its available cash, generally defined as all of its cash and cash equivalents on hand at the end of each quarter less cash reserves. PVR believes that it will continue to have adequate liquidity to fund future recurring operating and investing activities. Short-term cash requirements, such as operating expenses and quarterly distributions to PVR's general partner and unitholders, are expected to be funded through operating cash flows. 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.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2007:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	Thereafter
			(in thousands)		
Revolving credit facility	$122,000	$ —	$122,000	$ —	$ —
Convertible senior subordinated notes	230,000	—	—	230,000	—
PVR revolving credit facility	347,700	—	—	347,700	—
PVR senior unsecured notes	64,400	12,700	27,500	19,900	4,300
Asset retirement obligations	7,873	172	343	343	7,015
Derivatives	46,078	43,048	3,030	—	—
Interest expense	150,188	41,964	81,920	26,175	129
Unrecognized tax benefits (1)	9,852	1,466	—	—	8,386
Natural gas midstream activities (2)	40,307	11,838	10,913	10,202	7,354
Rental commitments (3)	22,524	8,641	9,208	4,675	—
Oil and gas activities (4)	24,346	9,555	10,557	2,162	2,072
Total contractual obligations	$1,065,268	$129,384	$265,471	$641,157	$29,256

(1) See Note 16, "Income Taxes," in the Notes to Consolidated Financial Statements for a further description of this liability.
(2) Commitments for natural gas midstream activities relate to firm transportation agreements.
(3) Rental commitments primarily relate to equipment and building leases and leases of coal reserve-based properties which PVR subleases, or intends to sublease, to third parties. The obligation with respect to leased properties which PVR subleases expires when the property has been mined to exhaustion or the lease has been canceled. The timing of mining by third party operators is difficult to estimate due to numerous factors. See Item 1A, "Risk Factors." We believe that the future rental commitments cannot be estimated with certainty; however, based on current knowledge and historical trends, PVR believes that it will incur $0.9 million in rental commitments annually until the reserves have been exhausted.
(4) Commitments for oil and gas activities relate to firm transportation agreements and drilling contracts.

Off-Balance Sheet Arrangements

At December 31, 2007, we did not have any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We are, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships.

Results of Operations

Selected Financial Data—Consolidated

The following table sets forth a summary of certain consolidated financial data for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands, except per share data)		
Revenues	$ 852,950	$ 753,929	$ 673,864
Expenses	660,326	583,397	511,847
Operating income	$ 192,624	$ 170,532	$ 162,017
Net income	$ 50,754	$ 75,909	$ 62,088
Earnings per share, basic	$ 1.33	$ 2.03	$ 1.67
Earnings per share, diluted	$ 1.32	$ 2.01	$ 1.66
Cash flows provided by operating activities	$ 313,030	$ 275,819	$ 231,407

Operating income increased in 2007 compared to 2006 primarily due to a $49.3 million increase in natural gas revenues, a $6.9 million increase in oil and condensate revenues, a $21.8 million increase in natural gas midstream gross processing margin, a $12.4 million gain on the sale of properties and an $5.7 million decrease in exploration expenses, partially offset by a $35.3 million increase in depreciation, depletion and amortization expenses, or DD&A, a $17.4 million increase in general and administrative expenses, a $20.2 million increase in operating expenses and a $4.1 million decrease in coal royalties revenues. Operating income increased in 2006 compared to 2005 primarily due to a $23.4 million increase in natural gas midstream gross processing margin, a $15.4 million increase in coal royalties revenues and a $6.6 million decrease in exploration expenses, partially offset by a $14.7 million increase in operating expenses and a $13.0 million increase in general and administrative expenses.

Net income decreased in 2007 compared to 2006 primarily due to a $66.8 million increase in derivative losses and a $12.6 million increase in interest expense, partially offset by the $22.1 million increase in operating income and the related $19.5 million net decrease in income tax expense. Net income increased in 2006 compared to 2005 primarily due to the $8.5 million increase in operating income and a $34.4 million increase in derivative gains, partially offset by a $9.5 million increase in interest expense and the related $9.3 million net increase in income tax expense.

The assets, liabilities and earnings of PVG are fully consolidated in our financial statements, with the public unitholders' interest (18% as of December 31, 2007) reflected as a minority interest in our consolidated financial statements. The assets, liabilities and earnings of PVR are fully consolidated in PVG's financial statements, with the public unitholders' interest (45%, after the effect of incentive distribution rights, as of December 31, 2007) reflected as minority interest in PVG's consolidated financial statements.

Oil and Gas Segment

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

The following table sets forth a summary of certain financial and other data for our oil and gas segment and the percentage change for the years ended December 31, 2007 and 2006:

	Year Ended December 31, 2007	Year Ended December 31, 2006	% Change	Year Ended December 31, 2006	Year Ended December 31, 2005
	(in thousands, except as noted)			(per Mcfe) (1)	
Revenues					
Natural gas	$ 262,169	$ 212,919	23%	$ 6.94	$ 7.35
Oil and condensate	28,117	21,237	32%	60.97	55.59
Other income	12,955	1,800	620%		
Total revenues	303,241	235,956	29%	7.47	7.55
Expenses					
Operating	46,713	27,403	70%	1.15	0.88
Taxes other than income	17,847	11,810	51%	0.44	0.38
General and administrative	16,281	12,826	27%	0.40	0.41
Production costs	80,841	52,039	55%	1.99	1.66
Exploration	28,608	34,330	(17%)	0.71	1.10
Impairment of oil and gas properties	2,586	8,517	(70%)	0.06	0.27
Depreciation, depletion and amortization	87,223	56,237	55%	2.15	1.80
Total expenses	199,258	151,123	32%	4.91	4.83
Operating income	$ 103,983	$ 84,833	23%	$ 2.56	$ 2.71
Production					
Natural gas (MMcf)	37,802	28,968	30%		
Oil and condensate (Mbbl)	461	382	21%		
Total production (MMcfe)	40,569	31,260	30%		

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

Production. Approximately 93% of production in 2007 and 2006 was natural gas. Total production increased by 9.3 Bcfe, or 30%, from 31.3 Bcfe in 2006 to 40.6 Bcfe in 2007 primarily due to increased production in the East Texas, Mid-Continent, Mississippi and Gulf Coast regions, partially offset by decreased production in the Appalachian region.

The following table summarizes total natural gas, oil and condensate production and total natural gas, oil and condensate revenues by region for the years ended December 31, 2007 and 2006:

Region	Natural Gas, Oil and Condensate Production, Year Ended December 31, 2007	2006	Natural Gas, Oil and Condensate Revenues, Year Ended December 31, 2007	2006
	(MMcfe)		(in thousands)	
Appalachia	12,426	12,759	$86,936	$96,683
Mississippi	7,551	6,411	53,737	47,801
Gulf Coast	8,477	6,296	65,300	48,596
East Texas	7,986	4,546	59,333	33,656
Mid-Continent	4,129	1,248	24,980	7,420
Total	40,569	31,260	$290,286	$234,156

We drilled a total of 289 gross (213.0 net) wells during 2007, including 271 gross (203.6 net) development wells and 18 gross (9.4 net) exploratory wells. All wells were successful except six gross (5.1 net) development wells, and three gross (1.6 net) exploratory wells, with four (2.6 net) wells under evaluation at December 31, 2007.

Revenues. Natural gas revenues increased by $49.3 million, or 23%, from $212.9 million in 2006 to $262.2 million in 2007. Of the $49.3 million increase, $64.9 million was the result of increased natural gas production, partially offset by a $15.6 million decrease resulting from lower realized prices for natural gas. Our average realized price received for natural gas decreased by $0.41 per Mcf, or 6%, from $7.35 per Mcf in 2006 to $6.94 per Mcf in 2007. Oil and condensate revenues increased by $6.9 million, or 32%, from $21.2 million in 2006 to $28.1 million in 2007. Of the $6.9 million increase, $4.4

million was the result of increased oil and condensate production and $2.5 million was the result of higher realized prices for crude oil. Our average realized price received for oil increased by $5.38 per Bbl, or 10%, from $55.59 per Bbl in 2006 to $60.97 per Bbl in 2007.

Natural gas, oil and condensate revenues are derived from the sale of our oil and gas production, which is net of the effects of the settlement of derivative contracts that previously followed hedge accounting. Settlement of our derivative contracts that do not follow hedge accounting has no effect on our reported revenues. Beginning in May 2006, none of our derivative contracts follow hedge accounting. Our revenues may vary significantly from period to period as a result of changes in commodity prices or production volumes. As part of our risk management strategy, we use derivative 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. The following table shows a summary of the effects of derivative activities on revenues and realized prices for the years ended December 31, 2007 and 2006:

	Year Ended December 31,			
	2007	2006	2007	2006
	(in thousands)		(per Mcf)	
Natural gas revenues, as reported	$ 262,169	$ 212,919	$ 6.94	$ 7.35
Derivatives (gains) losses included in natural gas revenues	(222)	(448)	(0.01)	(0.02)
Natural gas revenues before impact of derivatives	261,947	212,471	6.93	7.33
Cash settlements on natural gas derivatives	14,863	10,711	0.39	0.37
Natural gas revenues, adjusted for derivatives	$ 276,810	$ 223,182	$ 7.32	$ 7.70
	(in thousands)		(per Bbl)	
Crude oil revenues, as reported	$ 28,117	$ 21,237	$ 60.97	$ 55.59
Derivatives (gains) losses included in oil and condensate revenues	502	457	1.09	1.20
Oil and condensate revenues before impact of derivatives	28,619	21,694	62.06	56.79
Cash settlements on crude oil derivatives	(735)	(222)	(1.59)	(0.58)
Oil and condensate revenues, adjusted for derivatives	$ 27,884	$ 21,472	$ 60.47	$ 56.21

Other Income. Other income increased by $11.2 million, or 620%, from $1.8 million in 2006 to $13.0 million in 2007, primarily due to a $12.4 million gain on our September 2007 sale of non-operated working interests in oil and gas properties.

Expenses. Aggregate operating costs and expenses increased by $41.7 million, or 28%, from $151.1 million in 2006 to $199.0 million in 2007 primarily due to increases in operating expenses, taxes other than income, general and administrative expenses and DD&A expenses, partially offset by a decrease in exploration expenses and the impairment of properties.

Operating expenses increased by $19.3 million, or 70%, from $27.4 million, or $0.88 per Mcfe, in 2006 to $46.7 million, or $1.15 per Mcfe, in 2007. In addition to a general increase in oilfield service costs and activity in all operating areas, the increase was due to the 30% production increase and additional expenses in a number of operating areas related to workovers, water disposal, gathering, compression and maintenance.

Taxes other than income increased by $6.0 million, or 51%, from $11.8 million in 2006 to $17.8 million in 2007 primarily due to the 24% increase in oil and gas revenues and a severance tax credit received in 2006 related to production in the Cotton Valley play in East Texas and property tax adjustments in West Virginia.

General and administrative expenses increased by $3.5 million, or 27%, from $12.8 million in 2006 to $16.3 million in 2007 primarily due to an expansion of operations across the oil and gas segment, increased drilling activity and acquisitions, increased consulting costs and increased staffing and benefits costs. General and administrative costs, on a Mcfe basis, remained relatively constant at $0.40 in 2007 compared with $0.41 in 2006.

Exploration expenses in the years ended December 31, 2007 and 2006 consisted of the following:

	Year Ended December 31, 2007	2006
	(in thousands)	
Dry hole costs	$11,689	$15,178
Geological and geophysical	2,769	6,237
Unproved leasehold	13,036	9,410
Other	1,114	3,505
Total	$28,608	$34,330

Exploration expenses decreased by $5.7 million, or 17%, from $34.3 million in 2006 to $28.6 million in 2007 primarily due to decreases in dry hole costs and geological and geophysical costs, partially offset by an increase in unproved leasehold expenses. Dry hole costs decreased primarily due to write-offs of three exploratory wells in 2007 compared to eight wells in 2006. Geological and geophysical expenses decreased primarily due to a decrease in core-hole drilling, as well as a reduction in seismic purchases. Unproved leasehold expenses increased primarily due to a $2.7 million write-off of a prospect in the Williston Basin. Other costs decreased primarily due to a decrease in delay rental payments. In 2006, we incurred $1.8 million of delay rent charges caused by drilling delays in Louisiana.

We recorded $2.6 million of impairment charges in 2007 related to changes in estimates of the reserve bases of fields on certain properties in Oklahoma and Texas. We recorded $8.5 million of impairment charges in 2006 related to changes in estimates of reserve bases of certain fields in Louisiana, Texas and West Virginia.

DD&A expenses increased by $31.0 million, or 55%, from $56.2 million in 2006 to $87.2 million in 2007 primarily due to the 30% increase in equivalent production and higher depletion rates. Our average depletion rate increased from $1.80 per Mcfe in 2006 to $2.15 per Mcfe in 2007 primarily due to increased development costs and the sale of and reduced contributions from properties with lower depletion rates..

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

The following table sets forth a summary of certain financial and other data for our oil and gas segment and the percentage change for the years ended December 31, 2006 and 2005:

	2006	2005	% Change	2006	2005
	(in thousands, except as noted)			(per Mcfe)	
Revenues					
Natural gas	$ 212,919	$ 212,427	0%	$ 7.35	$ 8.31
Oil and condensate	21,237	13,792	54%	55.59	45.67
Other income	1,800	600	200%		
Total revenues	235,956	226,819	4%	7.55	8.29
Expenses					
Operating	27,403	17,300	58%	0.88	0.63
Taxes other than income	11,810	13,188	(10%)	0.38	0.48
General and administrative	12,826	9,264	38%	0.41	0.34
Production costs	52,039	39,752	31%	1.67	1.45
Exploration	34,330	40,917	(16%)	1.10	1.50
Impairment of oil and gas properties	8,517	4,785	78%	0.27	0.17
Depreciation, depletion and amortization	56,237	45,885	23%	1.80	1.68
Total expenses	151,123	131,339	15%	4.83	4.80
Operating income	$ 84,833	$ 95,480	(11%)	$ 2.71	$ 3.49
Production					
Natural gas (MMcf)	28,968	25,550	13%		
Oil and condensate (thousand barrels)	382	302	26%		
Total production (MMcfe)	31,260	27,362	14%		

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

Production. Approximately 93% of production in 2006 and 2005 was natural gas. Total production increased by 3.9 Bcfe, or 14%, from 27.4 Bcfe in 2005 to 31.3 Bcfe in 2006 primarily due to new production from increased drilling, including the Cotton Valley play in East Texas, the Selma Chalk development play in Mississippi and the success of our Fannett exploration prospect in south Texas drilled in the second quarter of 2005. The Mid-Continent region, acquired through the acquisition of Crow Creek in June 2006, added 1.2 Bcfe to 2006 production. Production increases were partially offset by normal field declines and water disposal issues, which resulted in shutting in or temporarily delaying production from some of our horizontal CBM wells in Appalachia.

We drilled a total of 210 gross (151.8 net) wells during 2006, including 190 gross (141.3 net) development wells and 20 gross (10.5 net) exploratory wells. All but three gross (2.4 net) development wells were successful. Thirteen exploratory wells (7.2 net) were successful, six exploratory wells (2.3 net) were not successful and one gross and net exploratory well is currently being tested. We have completed testing on three other exploratory wells that were under evaluation as of December 31, 2005 and have determined in 2006 that all three wells were unsuccessful. We wrote off $3.7 million of drilling costs in the third quarter of 2006 related to these wells.

The following table summarizes total natural gas, oil and condensate production and total natural gas, oil and condensate revenues by region for the years ended December 31, 2006 and 2005:

	Natural Gas, Oil and Condensate Production		Natural Gas, Oil and Condensate Revenues	
	Year Ended December 31,		Year Ended December 31,	
Region	2006	2005	2006	2005
	(MMcfe)		(in thousands)	
Appalachia	12,759	13,812	$96,683	$113,360
Mississippi	6,411	5,185	47,801	48,063
Gulf Coast	6,296	5,648	48,596	41,991
East Texas	4,546	2,717	33,656	22,805
Mid-Continent	1,248	—	7,420	—
Total	31,260	27,362	$234,156	$226,219

Revenues. Natural gas revenues increased slightly from $212.4 million in 2005 to $212.9 million in 2006. A $28.4 million increase in natural gas revenues resulting from increased natural gas production was almost fully offset by a $27.9 million decrease in natural gas revenues resulting from lower realized prices for natural gas. Our average realized price received for natural gas decreased by $0.96 per Mcf, or 12%, from $8.31 per Mcf in 2005 to $7.35 per Mcf in 2006. Oil and condensate revenues increased by $7.4 million, or 54%, from $13.8 million in 2005 to $21.2 million in 2006. Of the $7.4 million increase, $3.7 million was the result of increased oil and condensate production and $3.8 million was the result of higher realized prices for crude oil. Our average realized price received for oil increased by $9.92 per Bbl, or 22%, from $45.67 per Bbl in 2005 to $55.59 per Bbl in 2006.

Natural gas, oil and condensate revenues are derived from the sale of our oil and gas production, which is net of the effects of the settlement of derivative contracts that follow hedge accounting. Settlement of our derivative contracts that do not follow hedge accounting has no effect on our reported revenues. Beginning in May 2006, none of our derivative contracts follow hedge accounting. Our revenues may vary significantly from period to period as a result of changes in commodity prices or production volumes. As part of our risk management strategy, we use derivative 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. The following table shows a summary of the effects of derivative activities on revenues and realized prices for the years ended December 31, 2006 and 2005:

	Year Ended December 31,			
	2006	2005	2006	2005
	(in thousands)		(per Mcf)	
Natural gas revenues, as reported	$ 212,919	$ 212,427	$ 7.35	$ 8.31
Derivatives (gains) losses included in natural gas revenues	(448)	14,049	(0.02)	0.55
Natural gas revenues before impact of derivatives	212,471	226,476	7.33	8.86
Cash settlements on natural gas derivatives	10,711	(14,049)	0.37	(0.55)
Natural gas revenues, adjusted for derivatives	$ 223,182	$ 212,427	$ 7.70	$ 8.31
	(in thousands)		(per Bbl)	
Crude oil revenues, as reported	$ 21,237	$ 13,792	$ 55.59	$ 45.67
Derivatives (gains) losses included in oil and condensate revenues	457	857	1.20	2.84
Oil and condensate revenues before impact of derivatives	21,694	14,649	56.79	48.51
Cash settlements on crude oil derivatives	(200)	(857)	(0.52)	(2.84)
Oil and condensate revenues, adjusted for derivatives	$ 21,494	$ 13,792	$ 56.27	$ 45.67

Expenses. Aggregate operating costs and expenses increased by $19.8 million, or 15%, from $131.3 million in 2005 to $151.1 million in 2006 primarily due to increases in operating expenses, general and administrative expenses, impairment expense and DD&A expenses, partially offset by decreases in taxes other than income and exploration expenses.

Operating expenses increased by $10.1 million, or 58%, from $17.3 million, or $0.63 per Mcfe, in 2005 to $27.4 million, or $0.88 per Mcfe, in 2006 primarily due to 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 decreased by $1.4 million, or 11%, from $13.2 million in 2005 to $11.8 million in 2006 primarily due to a severance tax refund related to production in the Cotton Valley play, partially offset by higher severance taxes as a result of increased production.

General and administrative expenses increased by $3.5 million, or 38%, from $9.3 million in 2005 to $12.8 million in 2006 primarily due to increased payroll costs as a result of wage increases and new personnel and consulting fees.

Exploration expenses in the years ended December 31, 2006 and 2005 consisted of the following:

	Year Ended December 31,	
	2006	2005
	(in thousands)	
Dry hole costs	$15,178	$11,379
Geological and geophysical	6,237	7,739
Unproved leasehold	9,410	17,761
Other	3,505	4,038
Total	$34,330	$40,917

Exploration expenses decreased by $6.6 million, or 16%, from $40.9 million in 2005 to $34.3 million in 2006 primarily due to unproved leasehold and dry hole costs related to an exploratory well in south Texas that was determined to be unsuccessful in the second quarter of 2005. Dry hole costs increased primarily due to the write-off of exploratory wells. Geological and geophysical expenses decreased primarily due to the time of seismic data purchases. Unproved leasehold expenses decreased primarily due to the write-off of a well in South Texas in 2005. Other costs decreased primarily due to a decrease in delay rental payments.

We recorded $8.5 million of impairment charges in 2006 related to changes in estimates of reserve bases of certain fields in Louisiana, Texas and West Virginia. We recorded $4.8 million of impairment charges in 2005 related to changes in estimates of reserve bases of certain fields in Texas.

DD&A expenses increased by $10.4 million, or 23%, from $45.9 million in 2005 to $56.2 million in 2006 primarily due to the 14% increase in equivalent production and higher average depletion rates. Our average depletion rate increased from

$1.68 per Mcfe in 2005 to $1.80 per Mcfe in 2006 primarily due to 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.

PVR Coal and Natural Resource Management Segment

Year Ended December 31, 2007 Compared With Year Ended December 31, 2006

The following table sets forth a summary of certain financial and other data for the PVR coal and natural resource management segment and the percentage change for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		%	
	2007	2006	Change	
	(in thousands, except as noted)			
Financial Highlights				
Revenues				
Coal royalties	$ 94,140	$ 98,163	(4%)	$ 4,023
Coal services	7,252	5,864	24%	$ (1,388)
Timber	1,711	1,024	67%	$ (687)
Oil and gas royalty	1,864	957	95%	$ (907)
Other	6,672	6,973	(4%)	$ 301
Total revenues	111,639	112,981	(1%)	$ 1,342
Expenses				
Coal royalties	5,540	6,927	(20%)	$ 1,387
Other operating	2,531	1,673	51%	$ (858)
Taxes other than income	1,110	934	19%	$ (176)
General and administrative	10,957	9,604	14%	$ (1,353)
Depreciation, depletion and amortization	22,463	20,399	10%	$ (2,064)
Total expenses	42,601	39,537	8%	$ (3,064)
Operating income	$ 69,038	$ 73,444	(6%)	$ 4,406
Operating Statistics				
Royalty coal tons produced by lessees (tons in thousands)	32,528	32,778	(1%)	
Average royalty per ton ($/ton)	$ 2.89	$ 2.99	(3%)	

Revenues. Coal royalties revenues decreased by $4.1 million, or 4%, from $98.2 million in 2006 to $94.1 million in 2007 primarily due to a lower average royalty per ton. Tons produced by PVR's lessees remained relatively constant from 2006 to 2007. The mix of production in 2007 shifted from 2006, with higher lessee production in the Illinois Basin and the San Juan Basin, which have lower average royalties per ton, partially offset by lower lessee production in Central Appalachia, which has higher average royalties per ton. Primarily due to the combination of increased production in the relatively lower average royalty rate Illinois Basin and reduced production in Central Appalachia, PVR's average royalty per ton decreased by $0.10, or 3%, from $2.99 in 2006 to $2.89 in 2007.

The following table summarizes coal production and coal royalties revenues by property for the years ended December 31, 2007 and 2006:

Region	Coal Production Year Ended December 31, 2007	Coal Production Year Ended December 31, 2006	Coal Royalties Revenues Year Ended December 31, 2007	Coal Royalties Revenues Year Ended December 31, 2006
	(tons in thousands)		(in thousands)	
Central Appalachia	18,827	20,156	$68,815	$76,542
Northern Appalachia	4,194	5,009	6,434	7,314
Illinois Basin	3,779	2,540	7,432	4,768
San Juan Basin	5,728	5,073	11,459	9,539
Total	32,528	32,778	$94,140	$98,163

Coal services revenues increased by $1.4 million, or 24%, from $5.9 million in 2006 to $7.3 million in 2007 primarily due to the completed construction of a coal services facility in Knott County, Kentucky, which began operations in October 2006. Timber revenues increased by $0.7 million, or 67%, from $1.0 million in 2006 to $1.7 million in 2007 primarily due to the increased harvesting resulting from PVR's September 2007 forestland acquisition. Oil and gas royalty revenues increased by $0.9 million, or 95%, from $1.0 million in 2006 to $1.9 million in 2007 primarily due to the increased royalties resulting from PVR's October 2007 oil and gas royalty interest acquisition. Other revenues, which consisted primarily of wheelage fees, forfeiture income and management fee income, remained relatively constant from 2006 to 2007.

Expenses. Coal royalties expense decreased by $1.4 million, or 20%, from $6.9 million in 2006 to $5.5 million in 2007 primarily due to a decrease in production from properties PVR subleases in Central Appalachia. Other operating expenses increased by $0.8 million, or 51%, from $1.7 million in 2006 to $2.5 million in 2007 primarily due to an increase in mine maintenance and core-hole drilling expenses on PVR's Central Appalachian and Illinois Basin properties. General and administrative expenses increased by $1.4 million, or 14%, from $9.6 million in 2006 to $11.0 million in 2007 primarily due to increased staffing costs. DD&A expenses increased by $2.1 million, or 10%, from $20.4 million in 2006 to $22.5 million in 2007 primarily due to increased depletion resulting from PVR's forestland acquisition in September 2007. In addition, PVR began depreciating its coal services facility in Knott County, Kentucky, which began operations in October 2006.

Year Ended December 31, 2006 Compared With Year Ended December 31, 2005

The following table sets forth a summary of certain financial and other data for the PVR coal and natural resource management segment and the percentage change for the years ended December 31, 2006 and 2005:

	Year Ended December 31, 2006	Year Ended December 31, 2005	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Coal royalties	$ 98,163	$ 82,725	19%
Coal services	5,864	5,230	12%
Timber	1,024	776	32%
Oil and gas royalty	957	1,444	(34%)
Other	6,973	5,580	25%
Total revenues	112,981	95,755	18%
Expenses			
Coal royalties	6,927	4,151	67%
Other operating	1,673	1,604	4%
Taxes other than income	934	1,129	(17%)
General and administrative	9,604	9,237	4%
Depreciation, depletion and amortization	20,399	17,890	14%
Total expenses	39,537	34,011	16%
Operating income	$ 73,444	$ 61,744	19%
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	32,778	30,227	8%
Average royalty per ton ($/ton)	$ 2.99	$ 2.74	9%

Revenues. Coal royalties revenues increased by $15.5 million, or 19%, from $82.7 million in 2005 to $98.2 million in 2006 primarily due to a higher average royalty per ton and increased production. Tons produced by PVR's lessees increased by 2.6 million tons, or 8%, from 30.2 million tons in 2005 to 32.8 million tons in 2006, and PVR's average royalty per ton increased $0.25, or 9%, from $2.74 in 2005 to $2.99 in 2006. Coal production by PVR's lessees increased primarily due to the addition of production from the Illinois Basin reserves PVR acquired in July 2005 and increased production on PVR's Central Appalachian property due to additional property PVR acquired in May 2006. The average royalty per ton increased primarily due to a greater percentage of coal being produced from certain price-sensitive leases and, for most of 2006, stronger market conditions for coal resulting in higher prices.

The following table summarizes coal production and coal royalties revenues by property for the years ended December 31, 2006 and 2005:

Region	Coal Production Year Ended December 31, 2006	2005	Coal Royalties Revenues Year Ended December 31, 2006	2005
	(tons in thousands)		(in thousands)	
Central Appalachia	20,156	18,996	$76,542	$64,645
Northern Appalachia	5,009	4,958	7,314	6,973
Illinois Basin	2,540	1,449	4,768	2,709
San Juan Basin	5,073	4,824	9,539	8,398
Total	32,778	30,227	$98,163	$82,725

Coal services revenues increased by $0.7 million, or 12%, from $5.2 million in 2005 to $5.9 million in 2006 primarily due to increased equity earnings from PVR's coal handling joint venture and increased revenues from coal handling facilities that processed higher volumes. PVR's facility on its Central Appalachian property began operations in October 2006 and contributed $0.2 million to coal services revenues in 2006. Timber revenues increased by $0.2 million, or 32%, from $0.8 million in 2005 to $1.0 million in 2006 primarily due to an increase in forestland cutting in 2006. Cutting in 2005 was lower than in 2006 due to weather conditions. Oil and gas royalty revenues decreased by $0.4 million, or 34%, from $1.4 million in 2005 to $1.0 million in 2006 primarily due to a decrease in production and pricing. Other revenues increased by $1.4 million, or 25%, from $5.6 million in 2005 to $7.0 million in 2006 primarily due to a $0.9 million increase in revenues for the management of certain coal properties, a $1.1 million increase in forfeiture income due to timing of lease terms, a $0.4 million increase in railcar rental income related to railcars PVR purchased in June 2005 and a $0.6 million increase in wheelage fees primarily as a result of PVR's April 2005 coal reserve acquisition, partially offset the $1.5 million PVR received in 2005 from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents.

Expenses. Coal royalties expense increased by $2.7 million, or 67%, from $4.2 million in 2005 to $6.9 million in 2006 primarily due to production on PVR's subleased Central Appalachian property acquired in May 2006. This increase was partially offset by a decrease in production from other subleased properties primarily resulting from the movement of longwall mining operations at one of these properties. Fluctuations in production on subleased properties have a direct impact on coal royalties expense. Other operating expenses increased by $0.1 million, or 4%, from $1.6 million in 2005 to $1.7 million in 2006 primarily due to an increase in core-hole drilling expenses. General and administrative expenses increased by $0.4 million, or 4%, from $9.2 million in 2005 to $9.6 million in 2006 primarily due to absorbing operations related to PVR's 2005 and 2006 acquisitions, increased professional fees and payroll costs relating to evaluating acquisition opportunities and increased reimbursement to PVR's general partner for shared corporate overhead costs. DD&A expenses increased by $2.5 million, or 14%, from $17.9 million in 2005 to $20.4 million in 2006 primarily due to the increase in production and a higher depletion rate on recently acquired reserves.

PVR Natural Gas Midstream Segment

Year Ended December 31, 2007 Compared With Year Ended December 31, 2006

The following table sets forth a summary of certain financial and other data for the PVR natural gas midstream segment and the percentage change for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		
	2007	2006	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Residue gas	$ 242,129	$ 259,764	(7%)
Natural gas liquids	172,144	130,675	32%
Condensate	13,889	9,989	39%
Gathering and transportation fees	5,012	2,287	119%
Total natural gas midstream revenues	433,174	402,715	8%
Producer services	4,632	2,195	111%
Total revenues	437,806	404,910	8%
Expenses			
Cost of midstream gas purchased	343,293	334,594	3%
Operating	12,893	11,403	13%
Taxes other than income	1,926	1,420	36%
General and administrative	11,958	11,023	8%
Depreciation and amortization	18,822	17,094	10%
Total operating expenses	388,892	375,534	4%
Operating income	$ 48,914	$ 29,376	67%
Operating Statistics			
System throughput volumes (MMcf)	67,810	61,995	9%
Gross processing margin	$ 89,881	$ 68,121	32%

Gross Processing Margin. PVR's gross processing margin is the difference between its natural gas midstream revenues and its cost of midstream gas purchased. Natural gas midstream revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from system throughput volumes received, condensate collected and sold and gathering and other fees primarily from natural gas volumes connected to PVR's gas processing plants. Cost of midstream gas purchased consisted of amounts payable to third-party producers for natural gas purchased under percentage-of-proceeds and gas purchase/keep-whole contracts.

Natural gas midstream revenues increased by $30.5 million, or 8%, from $402.7 million in 2006 to $433.2 million in 2007. Cost of midstream gas purchased increased by $8.7 million, or 3%, from $334.6 million in 2006 to $343.3 million in 2007. PVR's gross processing margin increased by $21.8 million, or 32%, from $68.1 million in 2006 to $89.9 million in 2007. The gross processing margin increase was a result of a higher fractionation or "frac" spread, which is the difference between the price of NGLs sold and the cost of natural gas purchased on a per MMbtu basis, during 2007 and higher volumes of processed gas. Processed gas is the portion of the system throughput volumes that is actually processed at a processing facility. The increase in processed gas was attributable to PVR's success in contracting and connecting new supply to our facilities. Much of this new gas is a result of continued successful development by the producers operating in the vicinity of PVR's systems. Additionally, the pipeline acquired in 2006 allowed PVR to connect a number of gathering systems directly to its Beaver plant, bring its utilization of processing capacity to 100%. Gathering and transportation revenues benefited from a short-term gathering contract that was entered into and completed during the third quarter of 2007. These gathered volumes contributed to PVR's overall system throughput increase, but did not result in a corresponding increase in throughput volumes at our processing plants because the volumes were delivered off of the gathering system prior to reaching the processing facility. System throughput volumes at PVR's gas processing plants and gathering systems increased by 16 MMcfd, or 9%, from 170 MMcfd in 2006 to 186 MMcfd in 2007.

During 2007, PVR generated a majority of its gross processing margin from contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs. See Item 1, "Business—Contracts—PVR Natural Gas Midstream Segment," for a discussion of the types of contracts utilized by the PVR natural gas midstream segment. As part of PVR's risk management strategy, PVR uses derivative financial instruments to economically hedge NGLs sold and natural gas purchased. The following table shows a summary of the effects of derivative activities on PVR's gross processing margin for the years ended December 31, 2007 and 2006:

	Year Ended December 31,	
	2007	2006
	(in thousands)	
Gross processing margin, as reported	$ 89,881	$ 68,121
Derivatives expenses included in gross processing margin	4,595	1,953
Gross processing margin before impact of derivatives	94,476	70,074
Cash settlements on derivatives	(17,779)	(19,436)
Gross processing margin, adjusted for derivatives	$ 76,697	$ 50,638

Producer Services Revenues. Producer services revenues increased by $2.4 million, or 111%, from $2.2 million in 2006 to $4.6 million in 2007 primarily due to an increase in collected agent fees for the marketing of our natural gas production.

Expenses. Total operating costs and expenses remained relatively constant in 2007 compared to 2006.

Operating expenses increased by $1.5 million, or 13%, from $11.4 million in 2006 to $12.9 million in 2007 primarily due to a full year of operations in 2007 on the pipeline PVR acquired in 2006 and increased compressor rentals. General and administrative expenses increased by $0.9 million, or 8%, from $11.0 million in 2006 to $11.9 million in 2007 primarily due to increased staffing costs. Taxes other than income increased by $0.5 million, or 36%, from $1.4 million in 2006 to $1.9 million in 2007. Depreciation and amortization expenses increased by $1.7 million, or 10%, from $17.1 million in 2006 to $18.8 million in 2007. Increases in both taxes other than income and depreciation and amortization expenses were primarily due to capital spending on organic growth and acquisition opportunities occurring in both 2006 and 2007.

Year Ended December 31, 2006 Compared With Year Ended December 31, 2005

PVR began operating its natural gas midstream segment on March 3, 2005 with the acquisition of Cantera's natural gas midstream business. The results of operations of the PVR natural gas midstream segment since that date are discussed below.

The following table sets forth a summary of certain financial and other data for the PVR natural gas midstream segment and the percentage change for the years ended December 31, 2006 and 2005:

	Year Ended December 31,		
	2006	2005 (1)	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Residue gas	$ 259,764	$ 233,208	11%
Natural gas liquids	130,675	106,453	23%
Condensate	9,989	7,322	36%
Gathering and transportation fees	2,287	1,674	37%
Total natural gas midstream revenues	402,715	348,657	16%
Producer services	2,195	1,936	13%
Total revenues	404,910	350,593	15%
Expenses			
Cost of midstream gas purchased	334,594	303,912	10%
Operating	11,403	9,347	22%
Taxes other than income	1,420	1,268	12%
General and administrative	11,023	6,982	58%
Depreciation and amortization	17,094	12,738	34%
Total operating expenses	375,534	334,247	12%
Operating income	$ 29,376	$ 16,346	80%
Operating Statistics			
System throughput volumes (MMcf)	61,995	43,729	42%
Gross processing margin	$ 68,121	$ 44,745	52%

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

The financial and other data presented in the table above for 2005 include ten months of operations of PVR's natural gas midstream business. One of the primary reasons for the significant differences in PVR's results of operations for 2006 as compared to 2005 is that the 2006 data includes 12 full months of operations of PVR's natural gas midstream business.

Gross Processing Margin. Natural gas midstream revenues increased by $54.0 million, or 16%, from $348.7 million in 2005 to $402.7 million in 2006. Cost of midstream gas purchased increased by $30.7 million, or 10%, from $303.9 million in 2005 to $334.6 million in 2006. Cost of midstream gas purchased for 2006 was a $4.6 million non-cash charge to reserves for amounts related to balances assumed as part of the acquisition of Cantera. PVR's gross processing margin increased by $23.4 million, or 52%, from $44.7 million in 2005 to $68.1 million in 2006 primarily due to an additional two months of operations in 2006, higher average NGL and condensate prices and the overall increase in system throughput volumes in 2006 over 2005. System throughput volumes at PVR's gas processing plants and gathering systems increased by 27 MMcfd, or 19%, from 143 MMcfd in 2005 to 170 MMcfd in 2006.

During 2006, PVR generated a majority of its gross processing margin from contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs. See Item 1, "Business—PVR's Contracts—PVR Natural Gas Midstream Segment," for a discussion of the types of contracts utilized by the PVR natural gas midstream segment. As part of PVR's risk management strategy, PVR uses derivative financial instruments to economically hedge NGLs sold and natural gas purchased. The following table shows a summary of the effects of derivative activities on PVR's gross processing margin for the years ended December 31, 2006 and 2005:

	Year Ended December 31,	
	2006	2005
	(in thousands)	
Gross processing margin, as reported	$ 68,121	$ 44,745
Derivatives expenses included in gross processing margin	1,953	(988)
Gross processing margin before impact of derivatives	70,074	43,757
Cash settlements on derivatives	(19,436)	(4,752)
Gross processing margin, adjusted for derivatives	$ 50,638	$ 39,005

Producer Services Revenues. Producer services revenues remained relatively constant from 2006 to 2007.

Expenses. Operating costs and expenses increased due to an additional two months of activity in 2006 related to the PVR natural gas midstream segment that were not present in 2005, as well as due to increases in cost of midstream gas purchased, operating expenses, taxes other than income, general and administrative expenses and depreciation and amortization expenses.

Operating expenses increased by $2.1 million, or 22%, from $9.3 million in 2005 to $11.4 million in 2006 primarily due to rent and maintenance costs associated with additional compressors. General and administrative expenses increased by $4.0 million, or 58%, from $7.0 million in 2005 to $11.0 million in 2006 primarily due to additional personnel added to support the business and recent acquisitions and increased reimbursement to PVR's general partner for shared corporate overhead costs from $0.8 million in 2005 to $2.4 million in 2006. Depreciation and amortization expenses increased by $4.4 million, or 34%, from $12.7 million in 2005 to $17.1 million in 2006 primarily due to depreciation on the pipeline acquired in June 2006 and recent gathering system expansions.

Corporate and Other

Our corporate and other results consist of corporate operating expenses, interest expense, derivative gains and losses and minority interest.

Corporate Operating Expenses. Corporate operating expenses primarily consist of general and administrative expenses other than from our oil and gas segment and the PVR coal and natural resource management and PVR natural gas midstream segments. Corporate operating expenses increased by $12.4 million, or 72%, from $17.2 million in 2006 to $29.6 million in 2007 primarily due to increased general and administrative expenses resulting from wage increases, increased consulting expenses and the recognition of additional stock-based compensation expenses. Corporate operating expenses increased by $4.8 million, or 40%, from $12.2 million in 2005 to $17.2 million in 2006 primarily due to increased general and administrative expenses resulting from wage increases, new personnel and the recognition of $1.4 million for stock option expense upon adoption of SFAS No. 123(R), Share-Based Payment, on January 1, 2006.

Interest Expense. Interest expense increased by $12.0 million, or 49%, from $24.8 million in 2006 to $36.8 million in 2007 primarily due to interest incurred on additional borrowings under the Revolver to finance the acquisitions of oil and gas properties and additional drilling and development in our current oil and gas properties, partially offset by a $1.5 million decrease in PVR's interest expense in 2007. Interest expense increased by $9.5 million, or 62%, from $15.3 million in 2005 to $24.8 million in 2006 primarily due to interest incurred on additional borrowings under the Revolver and the PVR Revolver to finance 2006 acquisitions and a general increase in interest rates. We capitalized interest costs amounting to $3.7 million, $3.2 million and $3.5 million in 2007, 2006 and 2005 because the borrowings funded the preparation of unproved properties for their development and construction of facilities. PVR capitalized interest costs amounting to $0.8 million in 2007 because the borrowings funded the construction natural gas processing plants. PVR capitalized interest costs amounting to $0.3 million in 2006 related to the construction of a coal services facility in October 2006. PVR had no capitalized interest in 2005.

Derivatives. Derivative losses increased by $66.8 million, or 343%, from a $19.5 million gain in 2006 to a $47.3 million loss in 2007. The derivative losses in 2007 consisted of a $43.6 million unrealized loss for mark-to-market adjustments and a $3.7 million realized loss. Derivative gains increased by $34.4 million, or 232%, from a $14.9 million loss in 2005 to a $19.5 million gain in 2006. The derivative gains in 2006 consisted of a $19.0 million unrealized gain for mark-to-market adjustments and a $0.5 million unrealized gain for changes in hedge effectiveness.

Minority Interest. Minority interest represents PVG's net income allocated to the limited partner units owned by the public. In 2007 and 2006, minority interest reduced our consolidated income from operations by $30.2 million and $43.0 million. The decrease in minority interest was primarily due to the decrease in PVG's net income from $32.0 million in 2006 to $29.2 million in 2007 and the decrease in PVR's net income from $73.9 million in 2006 to $56.6 million in 2007. The decrease in minority interest was also due to an increase in distributions PVG receives on account of its incentive distribution rights, or IDRs, in PVR. PVR paid to PVG distributions with respect to its IDRs of $11.6 million and $4.3 million in 2007 and 2006.

Summary of 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 consolidated 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, or 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.

We determine depreciation and depletion of oil and gas producing properties by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves.

We deplete coal properties on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by PVR's own geologists and outside consultants. PVR's estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. We deplete timber on an area-by-area basis at a rate based upon the quantity of timber sold.

Oil and Gas Revenues

We record revenues associated with sales of natural gas, crude oil, condensate and NGLs when title passes to the customer. We recognize natural gas sales revenues from properties in which we have an interest with other producers 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. We treat any amount received in excess of our share as deferred revenues. If we take less than we are entitled to take, we record the under-delivery 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, we make accruals for revenues and accounts receivable 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. We record any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

Natural Gas Midstream Revenues

We recognize revenues from the sale of NGLs and residue gas when PVR sells the NGLs and residue gas produced at its gas processing plants. We recognize gathering and transportation revenues 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, we make accruals for revenues and accounts receivable and the related cost of midstream gas purchased and accounts payable based on estimates of natural gas purchased and NGLs and residue gas sold. We record any differences, which we do not expect to be significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Coal Royalties Revenues

We recognize coal royalties revenues on the basis of tons of coal sold by PVR's lessees and the corresponding revenues from those sales. Since PVR does not operate any coal mines, it does not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. We record any differences, which have historically not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

Derivative Activities

We and PVR historically have entered into derivative financial instruments that would qualify for hedge accounting under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Hedge accounting affects the timing of revenue recognition and cost of midstream gas purchased in our consolidated statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until the hedged transaction settles. Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). Because we no longer use hedge accounting for our commodity derivatives, we have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. PVR will recognize hedging losses of $5.5 million in 2008 related to settlements of natural gas midstream segment transactions. The discontinuation of hedge accounting has no impact on our reported cash flows, although results of operations are affected by the potential volatility of mark-to-market gains and losses, which fluctuate with changes in NGL, crude oil and natural 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 that 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 December 31, 2007, the costs attributable to unproved properties were $127.8 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 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 write-downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Environmental Matters

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

PVR's operations and those of its lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of PVR'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 PVR against any and all future environmental liabilities. PVR regularly visits its coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. PVR's management believes that its operations and those of its lessees comply with existing laws and regulations and does not expect any material impact on its financial condition or results of operations.

As of December 31, 2007 and 2006, PVR's environmental liabilities included $1.5 million and $1.6 million, which represents PVR's best estimate of the liabilities as of those dates related to its coal and natural resource management and natural gas midstream businesses. PVR 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. For a summary of the environmental laws and regulations applicable to PVR's operations, see Item 1, "Business—Government Regulation and Environmental Matters."

Recent Accounting Pronouncements

See Note 3 in the Notes to Consolidated Financial Statements for a description of recent accounting pronouncements.

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 and Section 21E of 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 risks set forth in Item 1A, "Risk Factors."

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the SEC. 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 7A *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 and PVR's customers and PVR's lessees. If our or PVR's customers or lessees become financially insolvent, they may not be able to continue to operate or meet their payment obligations.

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 and PVR's natural gas midstream business. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair values of our price risk management activities are significantly affected by fluctuations in the prices of natural gas, NGLs and crude oil.

For the year ended December 31, 2007, we reported a net derivative loss of $47.3 million. Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing 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, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. PVR will recognize hedging losses of $5.5 million in 2008 related to settlements of natural gas midstream segment transactions. The discontinuation of hedge accounting has no impact on our reported cash flows, although our results of operations are affected by the potential volatility of mark-to-market gains and losses, which fluctuate with changes in NGL, crude oil and natural gas prices. See the discussion and tables in Note 11 in the Notes to Consolidated Financial Statements for a description of our and PVR's derivatives programs.

Oil and Gas Segment

The following tables list our open mark-to-market derivative agreements and their fair values as of December 31, 2007:

	Average Volume Per Day	Weighted Average Price			Estimated Fair Value
		Additional Put Option	Floor	Ceiling	
					(in thousands)
Natural Gas Costless Collars	(in MMbtu)		(per MMbtu)		
First quarter 2008 (ceiling reduced to $8.50 for February and March only)	10,000		$9.00	$17.95	$1,511
First quarter 2008 (a) (February and March only)	20,000		$7.82	$8.50	—
Second quarter 2008	10,000		$7.50	$9.10	222
Third quarter 2008	10,000		$7.50	$9.10	222
Fourth quarter 2008 (October only)	10,000		$7.50	$9.10	74
Natural Gas Three-Way Collars	(in MMbtu)		(per MMbtu)		
First quarter 2008	22,500	$5.44	$8.00	$12.64	1,576
Second quarter 2008	22,500	$5.00	$7.11	$9.09	(65)
Third quarter 2008	22,500	$5.00	$7.11	$9.09	80
Fourth quarter 2008	22,500	$5.44	$7.70	$11.40	581
Fourth quarter 2008 (a)	30,000	$5.67	$8.58	$10.78	—
First quarter 2009	20,000	$5.75	$8.00	$12.80	310
First quarter 2009 (a)	30,000	$5.67	$8.58	$10.78	—
Second quarter 2009	10,000	$5.50	$7.50	$9.10	(95)
Third quarter 2009	10,000	$5.50	$7.50	$9.10	(243)
Natural Gas Swaps	(in MMbtu)		(per MMbtu)		
Second quarter 2008 (a)	30,000		$8.53	$8.53	—
Third quarter 2008 (a)	30,000		$8.53	$8.53	—
Settlements to be paid in subsequent period					(331)
Oil and gas segment commodity derivatives net asset					$3,842

(a) Entered into after December 31, 2007.

We estimate that excluding the derivative positions described above, for every $1.00 per MMBtu decrease or increase in natural gas prices, our operating income from oil and gas operations in 2008 would increase or decrease by approximately $43.5 million. This assumes that natural gas production remains constant at budgeted levels. In addition, we also estimate that for every $5.00 per barrel increase or decrease in the oil prices, our operating income from oil and gas operations would increase or decrease by approximately $4.0 million. This assumes that oil and other liquid production remains constant at budgeted levels. These estimated changes in operating income exclude the potential cash receipts or payments in settling these derivative positions.

PVR Natural Gas Midstream Segment

The following table lists PVR's open mark-to-market derivative agreements and their fair values as of December 31, 2007:

	Average Volume Per Day	Weighted Average Price	Weighted Average Price Collars Floor	Weighted Average Price Collars Ceiling	Estimated Fair Value
					(in thousands)
Frac Spreads	**(in MMbtu)**	**(per MMbtu)**			
First quarter 2008 through fourth quarter 2008	7,824	$5.02			$(11,599)
Ethane Sale Swaps	**(in gallons)**	**(per gallon)**			
First quarter 2008 through fourth quarter 2008	34,440	$0.4700			(6,279)
Propane Sale Swaps	**(in gallons)**	**(per gallon)**			
First quarter 2008 through fourth quarter 2008	26,040	$0.7175			(7,372)
Crude Oil Sale Swaps	**(in barrels)**	**(per barrel)**			
First quarter 2008 through fourth quarter 2008	560	$49.27			(8,788)
Natural Gasoline Collars	**(in gallons)**		**(per gallon)**		
First quarter 2008 through fourth quarter 2008	6,300		$1.4800	$1.6465	(953)
Crude Oil Collars	**(in barrels)**		**(per barrel)**		
First quarter 2008 through fourth quarter 2008	400		$65.00	$75.25	(2,669)
Natural Gas Purchase Swaps	**(in MMbtu)**	**(per MMbtu)**			
First quarter 2008 through fourth quarter 2008	4,000	$6.97			1,205
Settlements to be paid in subsequent period					(3,469)
Natural gas midstream segment commodity derivatives – net liability					**$(39,924)**

We estimate that excluding the derivative positions described above, for every $1.00 per MMBtu decrease or increase in natural gas prices from the $7.50 per MMbtu budgeted 2008 benchmark price, natural gas midstream gross processing margin and operating income in 2008 would increase or decrease by approximately $12.0 million. This assumes oil and other liquids prices and inlet volumes remain constant at budgeted levels. In addition, we also estimate that excluding the derivative positions described above, for every $5.00 per barrel increase or decrease in the oil prices from the $80.00 per barrel budgeted 2008 benchmark price, natural gas midstream gross processing margin and operating income would increase or decrease by approximately $10.8 million. This assumes natural gas prices and inlet volumes remain constant at budgeted levels. These estimated changes in gross processing margin and operating income exclude the potential cash receipts or payments in settling these derivative positions.

Interest Rate Risk

As of December 31, 2007, we had $122.0 million of outstanding indebtedness under the Revolver, which carries a variable interest rate throughout its term. We entered into the Revolver Swaps to effectively convert the interest rate on $50 million of the amount outstanding under the Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 5.34% plus the applicable margin until December 2010. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133. A 1% increase in short-term interest rates on the floating rate debt outstanding under the Revolver (net of amounts fixed through hedging transactions) at December 31, 2007 would cost us approximately $0.7 million in additional interest expense.

As of December 31, 2007, PVR had $347.7 million of outstanding indebtedness under the Revolver, which carries a variable interest rate throughout its term. PVR entered into the PVR Revolver Swaps in to effectively convert the interest rate on $160 million of the amount outstanding under the PVR Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 4.33% plus the applicable margin until March 2010. From March 2010 to December 2011, the PVR Revolver Swaps will effectively convert the interest rate on $100 million of the amount outstanding under the PVR Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 4.40% plus the applicable margin. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133. A 1% increase in short-term interest rates on the floating rate debt outstanding under the PVR Revolver (net of amounts fixed through hedging transactions) at December 31, 2007 would cost PVR approximately $1.9 million in additional interest expense.

Item 8 ***Financial Statements and Supplementary Data***

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation, a Virginia corporation, and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Penn Virginia Corporation and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for share-based payments, effective December 31, 2006, the Company changed its method of accounting for post-retirement plans, and effective January 1, 2007, the Company changed its method of accounting for tax uncertainties.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Penn Virginia Corporation's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Houston, Texas
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited Penn Virginia Corporation's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Penn Virginia Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting (Item 9A(b) herein). Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Penn Virginia Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Penn Virginia Corporation as of December 31, 2007 and 2006, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2007, and our report dated February 28, 2008 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
February 28, 2008

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

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

	Year Ended December 31,		
	2007	2006	2005
Revenues			
Natural gas	$ 262,169	$ 212,919	$ 212,427
Oil and condensate	28,117	21,237	13,792
Natural gas midstream	433,174	402,715	348,657
Coal royalty	94,140	98,163	82,725
Other	35,350	18,895	16,263
Total revenues	852,950	753,929	673,864
Expenses			
Cost of midstream gas purchased	343,293	334,594	303,912
Operating	67,610	47,406	32,685
Exploration	28,608	34,330	40,917
Taxes other than income	21,723	14,767	16,005
General and administrative	66,983	49,566	36,606
Impairment of oil and gas properties	2,586	8,517	4,785
Depreciation, depletion and amortization	129,523	94,217	76,937
Total expenses	660,326	583,397	511,847
Operating income	192,624	170,532	162,017
Other income (expense)			
Interest expense	(37,419)	(24,832)	(15,318)
Interest income and other	3,651	3,718	1,332
Derivatives	(47,282)	19,497	(14,885)
Income before minority interest and income taxes	111,574	168,915	133,146
Minority interest	30,319	43,018	30,389
Income tax expense	30,501	49,988	40,669
Net income	$ 50,754	$ 75,909	$ 62,088
Net income per share, basic	$ 1.33	$ 2.03	$ 1.67
Net income per share, diluted	$ 1.32	$ 2.01	$ 1.66
Weighted average shares outstanding, basic	38,061	37,362	37,092
Weighted average shares outstanding, diluted	38,358	37,732	37,464

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands)

	As of December 31, 2007	As of December 31, 2006
Assets		
Current assets		
Cash and cash equivalents	$ 34,527	$ 20,338
Accounts receivable	179,120	138,880
Deferred income taxes	16,273	-
Derivative assets	5,683	18,244
Other	8,469	14,921
Total current assets	244,072	192,383
Property and equipment		
Oil and gas properties (successful efforts method)	1,525,728	1,045,182
Other property and equipment	859,380	671,169
	2,385,108	1,716,351
Accumulated depreciation, depletion and amortization	(486,094)	(357,968)
Net property and equipment	1,899,014	1,358,383
Equity investments	25,640	25,355
Goodwill	7,718	7,718
Intangibles, net	28,938	33,045
Derivative assets	310	4,344
Other assets	47,769	11,921
Total assets	$ 2,253,461	$ 1,633,149
Liabilities and Shareholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 12,561	$ 10,832
Accounts payable and accrued liabilities	205,127	154,709
Derivative liabilities	43,048	7,149
Income taxes payable	1,163	-
Total current liabilities	261,899	172,690
Other liabilities	54,169	26,003
Derivative liabilities	3,030	7,065
Deferred income taxes	193,950	178,380
Long-term debt of the Company	352,000	221,000
Long-term debt of subsidiary	399,153	207,214
Minority interests of subsidiaries	179,162	438,372
Shareholders' equity		
Preferred stock of $100 par value – 100,000 shares authorized; none issued	-	-
Common stock of $0.01 par value – 64,000,000 shares authorized; 41,408,497 and 37,561,264 shares issued and outstanding at December 31, 2007 and December 31, 2006	225	188
Paid-in capital	485,998	100,559
Retained earnings	332,223	289,967
Deferred compensation obligation	1,608	1,314
Accumulated other comprehensive income	(7,936)	(7,954)
Treasury stock – 77,924 and 70,898 shares common stock, at cost, on December 31, 2007 and December 31, 2006	(2,020)	(1,649)
Total shareholders' equity	810,098	382,425
Total liabilities and shareholders' equity	$ 2,253,461	$ 1,633,149

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2007	2006	2005
Cash flows from operating activities			
Net income	$ 50,754	$ 75,909	$ 62,088
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	129,523	94,217	76,937
Commodity derivative contracts:			
Total derivative losses (gains)	52,157	(17,535)	28,803
Cash settlements of derivatives	(3,651)	(8,947)	(19,586)
Deferred income taxes	23,340	38,020	17,094
Minority interest	30,319	43,018	30,389
Impairment of oil and gas properties	2,586	8,517	4,785
(Gain) on sale of property and equipment	(12,553)	-	-
Dry hole and unproved leasehold expense	24,975	24,502	29,736
Other	5,098	4,260	5,989
Changes in operating assets and liabilities:			
Accounts receivable	(41,772)	(1,770)	(52,671)
Other current assets	421	(2,643)	(876)
Accounts payable and accrued liabilities	42,733	30,116	43,475
Other assets and liabilities	9,100	(11,845)	5,244
Net cash provided by operating activities	313,030	275,819	231,407
Cash flows from investing activities			
Proceeds from the sale of property and equipment	29,399	2,604	17,385
Acquisitions, net of cash acquired	(292,001)	(195,166)	(290,938)
Additions to property and equipment	(421,509)	(269,773)	(184,386)
Other	628	-	
Net cash used in investing activities	(683,483)	(462,335)	(457,939)
Cash flows from financing activities			
Dividends paid	(8,499)	(8,398)	(8,358)
Distributions paid to minority interest holders of PVR	(49,739)	(38,627)	(30,737)
Proceeds from PVR issuance of units	860	117,818	126,456
Proceeds from borrowings of the Company	513,500	162,000	78,000
Repayments of borrowings of the Company	(382,500)	(20,000)	(75,000)
Proceeds from borrowings of PVR	220,500	85,800	288,800
Repayments of borrowings of PVR	(27,000)	(122,900)	(151,600)
Payments for debt issuance costs	(8,141)	(668)	(2,835)
Net proceeds from PVA stock offering	135,441	-	-
Cash received for stock warrants sold	18,187	-	-
Cash paid for convertible note hedges	(36,817)	-	-
Other	8,850	5,916	2,248
Net cash provided by financing activities	384,642	180,941	226,974
Net increase (decrease) in cash and cash equivalents	14,189	(5,575)	442
Cash and cash equivalents – beginning of period	20,338	25,913	25,471
Cash and cash equivalents – end of period	$ 34,527	$ 20,338	$ 25,913
Supplemental disclosures:			
Cash paid during the periods for:			
Interest (net of amounts capitalized)	$ 34,794	$ 23,452	$ 12,978
Income taxes (net of refunds received)	$ (1,897)	$ 16,741	$ 15,455
Noncash investing activities:			
Deferred tax liabilities related to acquisition, net	$ -	$ 32,759	$ -
Issuance of PVR units for acquisition	$ -	$ -	$ 10,415
Assumption of liabilities in acquisitions	$ -	$ -	$ 3,981

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(in thousands)

	Shares Outstanding	Common Stock	Paid-in Capital	Retained Earnings	Deferred Compensation Obligation	Accumulated Other Comprehensive Income	Treasury Stock	Unearned Compensation and ESOP	Total Shareholders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2004	36,952	$ 185	$ 85,543	$ 168,726	$ -	$ (720)	$ -	$ (874)	$ 252,860	$ 34,885
Dividends paid ($0.45 per share)	-	-	-	(8,358)	-	-	-	-	(8,358)	
Recognition of gain on conversion of subordinated PVR units to common	-	-	6,393	-	-	-	-	-	6,393	
Stock issued as compensation	58	-	1,656	-	-	-	-	(1,507)	149	
PVR units issued as compensation, net	-	-	1,123	-	-	-	-	(426)	697	
Vesting of restricted units	-	-	(315)	-	-	-	-	-	(315)	
Exercise of stock options	238	1	3,561	-	-	-	-	-	3,562	
Deferred compensation	-	-	580	-	580	-	(832)	-	328	
Net income	-	-	-	62,088	-	-	-	-	62,088	$ 62,088
Other comprehensive loss, net of tax	-	-	-	-	-	(7,096)	-	-	(7,096)	(7,096)
Balance at December 31, 2005	37,248	186	98,541	222,456	580	(7,816)	(832)	(2,807)	310,308	$ 54,992
Adoption of SFAS No. 123(R) (See Note 18)	-	-	(2,807)	-	-	-	-	2,807	-	
Dividends paid ($0.45 per share)	-	-	-	(8,398)	-	-	-	-	(8,398)	
Sale of PVR & PVG securities	-	-	(3,560)	-	-	-	-	-	(3,560)	
Stock issued as compensation	12	-	691	-	-	-	-	-	691	
PVR units issued as compensation, net	-	-	1,229	-	-	-	-	-	1,229	
Vesting of restricted units	-	-	(1,056)	-	-	-	-	-	(1,056)	
Exercise of stock options	302	2	5,860	-	-	-	-	-	5,862	
Recognition of stock option expense	-	-	1,402	-	-	-	-	-	1,402	
Deferred compensation	-	-	734	-	734	-	(817)	-	651	
Contribution to GP Holdings of investment in PVR	-	-	(475)	-	-	-	-	-	(475)	
Net income	-	-	-	75,909	-	-	-	-	75,909	$ 75,909
Other comprehensive gain, net of tax	-	-	-	-	-	1,200	-	-	1,200	1,200
Adoption of SFAS No. 158, net of tax (See Note 16)	-	-	-	-	-	(1,338)	-	-	(1,338)	
Balance at December 31, 2006	37,562	188	100,559	289,967	1,314	(7,954)	(1,649)	-	382,425	$ 77,109
Dividends paid ($0.226 per share)	-	-	-	(8,498)	-	-	-	-	(8,498)	
Sale of PVR & PVG securities	-	-	(995)	-	-	-	-	-	(995)	
SAB 51 gain on PVR & PVG offerings	-	-	241,736	-	-	-	-	-	241,736	
Stock issued as compensation	19	-	878	-	-	-	-	-	878	
PVR units issued as compensation, net	-	-	1,583	-	-	-	-	-	1,583	
Vesting of restricted units	-	-	(1,099)	-	-	-	-	-	(1,099)	
Exercise of stock options	366	2	8,791	-	-	-	-	-	8,793	
Recognition of stock option expense	-	-	2,611	-	-	-	-	-	2,611	
Deferred compensation	11	-	613	-	294	-	(371)	-	536	
Common stock offering	3,450	35	131,321	-	-	-	-	-	131,356	
Net income	-	-	-	50,754	-	-	-	-	50,754	50,754
Other comprehensive gain, net of tax	-	-	-	-	-	18	-	-	18	18
Balance at December 31, 2007	41,408	$ 225	$ 485,998	$ 332,223	$ 1,608	$ (7,936)	$ (2,020)	$ -	$ 810,098	$ 50,772

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company primarily engaged in the exploration, development and production of natural gas and oil in various onshore U.S. regions including East Texas, the Mid-Continent, Appalachia, Mississippi and the Gulf Coast. We also indirectly own partner interests in Penn Virginia Resource Partners, L.P. ("PVR"). Our ownership interests in PVR are held principally through our general partner interest and our 82% limited partner interest in Penn Virginia GP Holdings, L.P. ("PVG"). PVG owns 100% of the general partner of PVR, which holds a 2% general partner interest in PVR, and an approximately 42% limited partner interest in PVR.

We are engaged in three primary business segments: (1) oil and gas, (2) coal and natural resource management and (3) natural gas midstream. We directly operate our oil and gas segment. PVR operates our coal and natural resource management and natural gas midstream segments. Because we control the general partner of PVG, the financial results of PVG are included in our consolidated financial statements. Because PVG controls the general partner of PVR, the financial results of PVR are included in PVG's consolidated financial statements. However, PVG and PVR function with capital structures that are independent of each other and us, with each having publicly traded common units and PVR having its own debt instruments. PVG does not currently have any debt instruments.

2. Penn Virginia Resource Partners, L.P. and Penn Virginia GP Holdings, L.P.

PVR is a publicly traded Delaware limited partnership formed by Penn Virginia in 2001 that is principally engaged in the management of coal and natural resource properties and the gathering and processing of natural gas in the United States. PVR completed its initial public offering (the "PVR IPO") in October 2001. PVG completed its initial public offering (the "PVG IPO") in December 2006, selling approximately 18% of its outstanding units to the public and using the proceeds from the offering to purchase newly issued common and Class B units from PVR.

The PVR coal and natural resource management segment primarily involves the management and leasing of coal and natural resource properties and the subsequent collection of royalties. PVR also earns revenues from the provision of fee-based coal preparation and loading services, from the sale of standing timber on its properties, from oil and gas royalty interests it owns and from coal transportation, or wheelage, fees.

The PVR natural gas midstream segment is engaged in providing gas processing, gathering and other related natural gas services. PVR owns and operates natural gas midstream assets located in Oklahoma and the panhandle of Texas. PVR's natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. PVR also owns a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

3. Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of Penn Virginia, all of its wholly-owned subsidiaries and PVG, of which we indirectly owned the sole general partner and an approximately 82% limited partner interest as of December 31, 2007. PVG GP, LLC, our wholly-owned subsidiary, serves as PVG's general partner and controls PVG. Intercompany balances and transactions have been eliminated in consolidation. Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America 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 our consolidated financial statements have been included. Certain reclassifications have been made to conform to the current year's presentation.

Prior to December 5, 2006, our ownership of PVR included our ownership of limited partner interests in PVR and our ownership of Penn Virginia Resource GP, LLC, which is PVR's general partner and owns the incentive distribution rights in PVR. Our sole ownership of Penn Virginia Resource GP, LLC provided us with a 2% general partner interest in PVR. Our general partner interest gave us control of PVR as the holders limited partner interests of PVR: (i) do not have the substantive ability to dissolve PVR, (ii) can remove Penn Virginia Resource GP, LLC as PVR's general partner only with a supermajority vote of the PVR limited partner interests and the PVR limited partner interests which can be voted in such an election are restricted, and (iii) the PVR limited partners do not possess substantive participating rights in PVR's operations. Therefore, our consolidated financial statements prior to December 5, 2006 include the assets, liabilities and cash flows of Penn Virginia Resource GP, LLC and PVR.

PVG's only cash-generating assets are its ownership interest in Penn Virginia Resource GP, LLC, which owns the general partner interest and incentive distribution rights in PVR, and its ownership of limited partner interests in PVR. Therefore, PVG's cash flows are dependent upon PVR's ability to make cash distributions, and the distributions PVG receives are subject to PVR's cash distribution policies.

The minority interests of subsidiaries on our consolidated balance sheets reflect the outside ownership interest of PVG and PVR as of December 31, 2007 and the outside ownership interest of PVR as of December 31, 2006 when taking into consideration the allocations made related to Penn Virginia Resource GP, LLC's incentive distribution rights. PVG's outside ownership interest was 18% at December 31, 2007 and December 31, 2006. PVR's outside ownership interest was 56% at December 31, 2007 and 2006 and 61% at December 31, 2005.

Use of Estimates

Preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

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

Oil and Gas Properties

We use the successful efforts method 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 completion 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 that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. As of December 31, 2007, we had capitalized $4.3 million of exploratory drilling costs related to four exploratory wells which reached total depth in 2007, but were under evaluation for commercial viability.

The costs of unproved leaseholds, including associated interest costs for the period activities were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. Interest costs associated with non-producing leases were capitalized in the amounts of $3.7 million, $2.8 million and $3.5 million in 2007, 2006 and 2005. 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 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 write-downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results. As of December 31, 2007, 2006 and 2005, unproved leasehold costs amounted to $127.8 million, $100.0 million and $66.7 million.

Other Property and Equipment

Other property and equipment primarily consist of PVR's ownership in coal fee mineral interests, PVR's royalty interest in oil and natural gas wells, forestlands, processing facilities, gathering systems, compressor stations and related equipment. Property and equipment are carried at cost and include expenditures for additions and improvements, such as roads and land improvements, which increase the productive lives of existing assets. Maintenance and repair costs are expensed as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. We compute depreciation and amortization of property and equipment using the straight-line balance method over the estimated useful life of each asset as follows:

	Useful Life
Gathering systems	15 years
Compressor stations	5-15 years
Processing plants	15 years
Other property and equipment	3-20 years

We deplete coal properties on an area-by-area basis at a rate based upon the cost of the mineral properties and estimated proven and probable tonnage therein. From time to time, PVR carries out core-hole drilling activities on its coal properties in order to ascertain the quality and quantity of the coal contained in those properties. These core-hole drilling activities are expensed as incurred. We deplete timber on an area-by-area basis at a rate based upon the quantity of timber sold. We deplete oil and gas properties on a unit-of-production basis over the remaining life of the reserves. When we retire or sell an asset, we remove its cost and related accumulated depreciation and amortization from our consolidated balance sheets. We record the difference between the net book value (net of any related asset retirement obligation) and proceeds from disposition as gain or loss.

Asset Retirement Obligations

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations,* we recognize the fair value of a liability for an asset retirement obligation (an "ARO") in the period in which it is incurred. The determination of fair value is based upon regional market and specific well type information. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. See Note 13, "Asset Retirement Obligations." The amount of an ARO and the costs capitalized equal the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using an assumed cost of funds for us. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds, and the additional capitalized costs are depreciated over the productive life of the assets. Both the accretion and the depreciation are included in depreciation, depletion and amortization expense on our consolidated statements of income. In connection with PVR's natural gas midstream assets, we are obligated under federal regulations to perform limited procedures around the abandonment of pipelines. We are unable to reasonably determine the fair value of such ARO because the settlement dates, or ranges thereof, are indeterminable. An ARO will be recorded in the period wherein we can reasonably determine the settlement dates.

Impairment of Long-Lived Assets

We review long-lived assets to be held and used whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. We recognize an impairment loss when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the present value of future net cash flows from the asset, discounted utilizing a rate commensurate with the risk and remaining life of the asset. See Note 10, "Impairment of Oil and Gas Properties."

Equity Investments

We use the equity method of accounting to account for PVR's investment in a coal handling joint venture, recording PVR's initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect PVR's share of income of the investee and is reduced to reflect PVR's share of losses of the investee or distributions received from the investee as the joint venture reports them. PVR's share of earnings or losses from the investment is included in other revenues on our consolidated statements of income. Other revenues also include amortization of the amount of PVR's equity investment that exceeds its portion of the underlying equity in net assets. We record amortization over the life of coal services contracts in place at the time of PVR's initial investment.

Goodwill

We had approximately $7.7 million of goodwill at December 31, 2007 and 2006 based upon the purchase price allocation for the Cantera Acquisition (as defined in Note 4). The goodwill has been allocated to the PVR natural gas midstream segment. In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets,* goodwill is assessed at least annually for impairment. We tested goodwill for impairment during the fourth quarter of 2007 and determined that no impairment charge was necessary.

Intangible Assets

Intangible assets at December 31, 2007 and 2006 included $37.7 million for customer contracts and relationships and $4.6 million for rights-of-way acquired in the Cantera Acquisition (see Note 4). Customer contracts and relationships are amortized on a straight-line basis over the expected useful lives of the individual contracts and relationships, up to 15 years. Rights-of-way are amortized on a straight-line basis over a period of 15 years. Total intangible amortization expense for the years ended December 31, 2007, 2006 and 2005 was approximately $4.1 million, $5.0 million and $4.2 million. As of December 31, 2007, accumulated amortization of intangible assets was $13.3 million. The following table sets forth our estimated aggregate amortization expense for the next five years and thereafter:

Year	Amortization Expense
	(in thousands)
2008	$3,485
2009	3,219
2010	3,006
2011	2,764
2012	2,515
Thereafter	13,949
Total	$28,938

Concentration of Credit Risk

Approximately 55% of our consolidated accounts receivable at December 31, 2007 resulted from our oil and gas segment, approximately 39% resulted from the PVR natural gas midstream segment and approximately 6% resulted from the PVR coal and natural resource management segment. Approximately 11% of our consolidated accounts receivable at December 31, 2007 related to one natural gas midstream customer and approximately 14% of our consolidated accounts receivable at December 31, 2007 related to one oil and gas customer. These concentrations may impact our overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral from a customer, joint interest owner or lessee, we analyze the entity's net worth, cash flows, earnings and credit ratings to the extent information is available. Receivables are generally not collateralized. Historical credit losses incurred on receivables have not been significant.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, derivative instruments, a capital lease and long-term debt. The carrying values of all of these financial instruments, except fixed rate long-term debt, approximate fair value. The fair value of fixed rate long-term debt at December 31, 2007 and 2006 was $295.8 million and $75.4 million.

Revenues

Oil and Gas Revenues. We record revenues associated with sales of natural gas, crude oil, condensate and natural gas liquids ("NGLs") when title passes to the customer. We recognize natural gas sales revenues from properties in which we have an interest with other producers 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. We treat any amount received in excess of our share as deferred revenues. If we take less than we are entitled to take, we record the under-delivery 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, we make accruals for revenues and accounts receivable 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. We record any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

Natural Gas Midstream Revenues. We recognize revenues from the sale of NGLs and residue gas when PVR sells the NGLs and residue gas produced at its gas processing plants. We recognize gathering and transportation revenues 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, we make accruals for revenues and accounts receivable and the related cost of midstream gas purchased and accounts payable based on estimates of natural gas purchased and NGLs and residue gas sold. We record any differences, which have not historically been significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Coal Royalties Revenues and Deferred Income. We recognize coal royalties revenues on the basis of tons of coal sold by PVR's lessees and the corresponding revenues from those sales. Since PVR does not operate any coal mines, it does not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. We record any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates in the period they become finalized. Most of PVR's lessees must take minimum monthly or annual payments that are generally recoupable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recoups a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalties revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods, the deferred income attributable to the minimum payment is recognized as minimum rental revenues, which is a component of other income on our consolidated statements of income. Deferred income also includes unearned income from a coal services facility lease, which is recognized as interest income as it is earned.

Derivative Activities

From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas, crude oil and NGL price volatility. The derivative financial instruments, which are placed with major financial institutions that we believe are minimum credit risks, take the form of costless collars, three-way options and swaps. All derivative financial instruments are recognized in our consolidated financial statements at fair value in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* The fair values of our derivative instruments are determined based on third party forward price quotes. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

We and PVR historically have entered into derivative financial instruments that would qualify for hedge accounting under SFAS No. 133. Hedge accounting affects the timing of revenue recognition and cost of midstream gas purchased in our consolidated statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until the hedged transaction settles. Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing 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, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. See Note 11, "Derivative Instruments."

Income Taxes

We account for income taxes in accordance with the provisions of SFAS No. 109, *Accounting for Income Taxes*, which requires a company to recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in a company's financial statements or tax returns. Using this method, deferred tax liabilities and assets are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates.

Stock-Based Compensation

We have several 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. The general partners of PVG and PVR both have long-term incentive plans that permit the granting of awards to their directors and employees and employees of their affiliates who perform services for PVG and PVR. 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 included 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 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), Share-Based Payment. Results for prior periods have not been restated. See Note 19, "Share-Based Payments".

Pension Plans and Other Post-Retirement Benefits

On December 31, 2006, we adopted the recognition and disclosure provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. SFAS No. 158 required us to recognize the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligations) of our pension and other post-retirement benefit plans on our consolidated statement of financial position at December 31, 2006, with a corresponding adjustment to accumulated other comprehensive income ("AOCI"), net of tax. See Note 17, "Employee Benefit Plans".

Accounting for Uncertainty in Income Taxes

We adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* ("FIN 48") as of January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We also adopted FASB Staff Position No. FIN 48−1, *Definition of Settlement in FASB Interpretation No.48* ("FSP FIN 48−1") as of January 1, 2007. FSP FIN 48−1 provides that a company's tax position will be considered settled if the taxing authority has completed its examination, the company does not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. The adoption of FIN 48 did not result in a transition adjustment to retained earnings; instead, $8.7 million was reclassified from deferred income taxes to a long-term liability. See Note 16, "Income Taxes".

Adoption of Staff Accounting Bulletin No. 108

In September 2006, the SEC issued SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB No. 108 expresses the SEC staff's views regarding the process of quantifying financial statement misstatements. The SEC staff believes registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct errors existing in prior years that previously had been considered immaterial, quantitatively and qualitatively, based on appropriate use of the registrant's approach. SAB No. 108 describes the circumstances where this would be appropriate as well as required disclosures to investors. SAB No. 108 is effective for fiscal years ending on or after November 15, 2006. We adopted SAB No. 108 as of December 31, 2006. Adoption of SAB No. 108 had no effect on our financial position or results of operations.

New Accounting Standards

In September 2006, the Financial Accounting Standards Board (the "FASB") issued SFAS No. 157, *Fair Value Measurements*, which provides enhanced guidance for using fair value to measure assets and liabilities. SFAS No.157 requires us to evaluate the fair value of our assets and liabilities according to a specified fair value hierarchy and present additional disclosures. SFAS No. 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value. SFAS No. 157 does not expand the use of fair value in any new circumstances. SFAS No. 157 is to be applied prospectively, except for in certain situations, none of which apply to us. We adopted SFAS No. 157 as of January 1, 2008 and are currently in the process of determining the effects of adoption, such as the effect of incorporating our own credit standing in the measurement of certain liabilities. We do not expect that the final effects of adoption will have a significant impact on our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115*, which provides companies with an option to report selected financial assets and liabilities at fair value. The objective of SFAS No. 159 is to reduce both the complexity in accounting for financial instruments and the volatility in earnings caused by measuring related assets and liabilities differently. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of an entity's first fiscal year beginning after November 15, 2007. We adopted SFAS 159 as of January 1, 2008. The adoption of SFAS No. 159 had no effect on our consolidated financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS No.141(R)"). SFAS No. 141(R) provides companies with principles and requirements on how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree as well as the recognition and measurement of goodwill acquired or a gain from a bargain purchase in a business combination. SFAS No. 141(R) also requires certain disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. Acquisition costs associated with the business combination will generally be expensed as incurred. In addition, changes in an acquired entity's valuation allowance for deferred tax assets and uncertain tax positions after the measurement period will impact income tax expense. SFAS No. 141(R) is effective for business combinations occurring in fiscal years beginning after December 15, 2008. Early adoption of SFAS No. 141(R) is not permitted. We are currently assessing the impact SFAS No. 141(R) will have on our process of analyzing business combinations.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*, which mandates that a noncontrolling (minority) interest shall be reported in the consolidated statement of financial position within equity, separately from the parent company's equity. This statement amends ARB No. 51 and clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity. SFAS No. 160 also requires consolidated net income to include amounts attributable to both parent and noncontrolling interest and requires disclosure, on the face of the consolidated statement of income, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS No. 160 is effective for fiscal years and interim periods beginning after December 15, 2008. We are currently assessing the impact on our consolidated financial statements of adopting SFAS No. 160 effective January 1, 2009.

4. Acquisitions and Dispositions

In the following paragraphs, all references to coal, oil and natural gas reserves and acreage acquired are unaudited. The factors we used to determine the fair market value of acquisitions include, but are not limited to, discounted future net cash flows on a risked-adjusted basis, geographic location, quality of resources, potential marketability and financial condition of lessees.

Business Acquisitions

On March 3, 2005, PVR completed its acquisition (the "Cantera Acquisition") of Cantera Gas Resources, LLC, a natural gas midstream gas gathering and processing company with primary locations in Oklahoma and Texas. The results of operations of PVR Midstream LLC since March 3, 2005, the closing date of the Cantera Acquisition, are included in our consolidated statements of income.

Cash paid in connection with the Cantera Acquisition was $199.2 million, net of cash received and including capitalized acquisition costs, which PVR funded with a $110 million term loan and with long-term debt under PVR's revolving credit facility. PVR used proceeds of $126.4 million from its sale of common units in a subsequent public offering in March 2005 and a $2.6 million contribution from its general partner to repay the term loan in full and to reduce outstanding indebtedness under its revolving credit facility. The total purchase price was allocated to the assets purchased and the liabilities assumed in the Cantera Acquisition based upon the fair values on the date of acquisition as follows (in thousands):

Cash consideration paid for Cantera	$201,326
Plus: Acquisition costs	3,275
Total purchase price	204,601
Less: Cash acquired	(5,378)
Total purchase price, net of cash acquired	$199,223
Current assets acquired	$43,697
Property and equipment acquired	145,448
Other assets acquired	645
Liabilities assumed	(38,337)
Intangible assets	40,052
Goodwill	7,718
Total purchase price, net of cash acquired	$199,223

The purchase price allocation includes approximately $7.7 million of goodwill. The significant factors that contributed to the recognition of goodwill include PVR's entry into the natural gas midstream business and its ability to acquire an established business with an assembled workforce.

Under SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets,* goodwill recorded in connection with a business combination is not amortized, but rather is tested for impairment at least annually. Accordingly, the unaudited pro forma financial information presented below does not include amortization of the goodwill recorded in the Cantera Acquisition. The purchase price allocation also includes $40.1 million of intangible assets that are primarily associated with assumed customer contracts, customer relationships and rights-of-way. These intangible assets are being amortized over periods of up to 15 years, the period in which benefits are derived from the acquired contracts, relationships and rights-of-way, and are reviewed for impairment under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

The following unaudited pro forma financial information reflects our consolidated results of operations as if the Cantera Acquisition and related debt and equity financings had occurred on January 1, 2005. The pro forma information includes adjustments primarily for depreciation of acquired property and equipment, amortization of intangible assets and interest expense for acquisition debt. The pro forma financial information is not necessarily indicative of the results of operations as it would have been had these transactions been effected on the assumed date.

	Year Ended December 31, 2005 (unaudited) (in thousands, except per share data)
Revenues	$692,228
Net income	$62,179
Net income per share, basic	$3.35
Net income per share, diluted	$3.32

In September 2007, PVR acquired fee ownership of approximately 62,000 acres of forestland in northern West Virginia. The purchase price was $93.3 million in cash and was funded with long-term debt under PVR's revolving credit facility. The purchase price has been preliminarily allocated as follows: $5.9 million to land and $87.4 million to timber. The purchase price allocation is preliminary. PVR is awaiting final appraisals of an assumed contract and additional analysis on the fair value of the land and timber.

In August 2007, we acquired the lease rights to property covering approximately 22,700 acres located in eastern Oklahoma with estimated proved reserves of 18.8 billion cubic feet of natural gas ("Bcfe"). The purchase price was $47.9 million in cash and was funded with long-term debt under our revolving credit facility. We acquired these assets in order to expand our oil and gas segment business. The acquisition has been recorded as a component of oil and gas properties.

In June 2007, PVR acquired a combination of fee ownership and lease rights to approximately 51 million tons of coal reserves, along with a preparation plant and coal handling facilities. The property is located on approximately 17,000 acres in western Kentucky. The purchase price was $42.0 million in cash and was funded with long-term debt under PVR's revolving credit facility. The purchase price allocation has been allocated as follows: $30.0 million to coal properties, $0.5 million to land, $28.1 million to a lease receivable and $16.6 million to deferred rent relating to a coal services facility lease.

In June 2006, we acquired 100% of the capital stock of Crow Creek Holding Corporation ("Crow Creek"). Crow Creek was a privately owned independent exploration and production company with operations primarily in the Oklahoma portions of the Arkoma and Anadarko Basins. Crow Creek's assets included estimated net proved reserves of 42.7 Bcfe, approximately 85% of which were natural gas. The purchase price was $71.5 million in cash and was funded with long-term debt under our revolving credit facility.

The pro forma results for the years ended December 31, 2007, 2006 and 2005 for the northern West Virginia, the eastern Oklahoma, the western Kentucky and Crow Creek acquisitions do not materially change the historical results for those periods.

Other Acquisitions and Dispositions

Oil and Gas Segment

In October 2007, we acquired lease rights to property covering 4,800 acres located in east Texas, with estimated proved reserves of 21.9 Bcfe. The purchase price was $44.9 million in cash and was funded with long-term debt under our revolving credit facility.

In October 2007, we sold to PVR oil and gas royalty interests associated with leases of property in eastern Kentucky and southwestern Virginia with estimated proved reserves of 8.7 Bcfe at January 1, 2007. The sale price was $31.0 million in cash, and the proceeds of the sale were used to repay borrowings under our revolving credit facility. The gain on the sale and the related depletion expense were eliminated in the consolidation of our financial statements.

In September 2007, we sold non-operated working interests in oil and gas properties located in eastern Kentucky and southwestern Virginia, with estimated proved reserves of 13.3 Bcfe. The sale price was $29.1 million in cash, and the proceeds of the sale were used to repay borrowings under our revolving credit facility. We recognized a gain of $12.4 million on the sale, which is reported in the revenues section of our consolidated statements of income.

In July 2007, we acquired lease rights to property covering approximately 4,000 acres located in east Texas, with estimated proved reserves of 19.5 Bcfe. The purchase price was $22.0 million in cash and was funded with long-term debt under our revolving credit facility.

PVR Coal and Natural Resource Management Segment

In October 2007, PVR purchased from us oil and gas royalty interests associated with leases of property in eastern Kentucky and southwestern Virginia with estimated proved reserves of 8.7 Bcfe at January 1, 2007. The purchase price was $31.0 million in cash and was funded with long-term debt under PVR's revolving credit facility.

In June 2006, PVR completed the acquisition of approximately 115 miles of gathering pipelines and related compression facilities in Texas and Oklahoma. These assets are contiguous to PVR's Beaver/Perryton System. The purchase price was $14.7 million and was funded with cash. Subsequently, PVR borrowed $14.7 million under its revolving credit facility to replenish the cash used for the acquisition.

In May 2006, PVR acquired lease rights to approximately 69 million tons of coal reserves. The reserves are located on approximately 20,000 acres in northern West Virginia. The purchase price was $65.0 million and was funded with long-term debt under PVR's revolving credit facility.

In July 2005, PVR acquired fee ownership of approximately 94 million tons of coal reserves. The reserves are located along the Green River in the western Kentucky portion of the Illinois Basin. The purchase price was $62.4 million in cash and the assumption of $3.3 million of deferred income and was funded with long-term debt under PVR's revolving credit facility.

PVR Natural Gas Midstream Segment

In June 2006, PVR completed the acquisition of approximately 115 miles of gathering pipelines and related compression facilities in Texas and Oklahoma. These assets are contiguous to PVR's Beaver/Perryton System. The purchase price was $14.7 million and was funded with cash. Subsequently, PVR borrowed $14.7 million under its revolving credit facility to replenish the cash used for the acquisition.

5. Stock Split

On May 8, 2007, our board of directors approved a two-for-one-split of our common stock in the form of a 100% stock dividend payable on June 19, 2007 to shareholders of record on June 12, 2007. Shareholders received one additional share of common stock for each share held on the record date. All common shares and per share data have been retroactively adjusted to reflect the stock split.

6. Gain on Sale of Subsidiary Units

We accounted for the PVR IPO and each subsequent PVR equity issuance as a sale of a minority interest. For each PVR equity issuance, we calculated a gain under SEC Staff Accounting Bulletin No. 51 (or Topic 5-H), *Accounting for Sales of Stock by a Subsidiary* ("SAB 51"). Because the PVR common units had preference over the PVR subordinated units with respect to distributions, the gain was not recognized at the time of each PVR equity issuance. This gain was to be recognized in shareholders' equity when all of the subordinated units converted to common units. By November 2006, all of the subordinated units had converted to common units. However, because the issuance of the PVR Class B units, which were subordinate to the PVR common units with respect to distributions, was contemplated at the time the final PVR subordinated units converted to PVR common units in November 2006, we did not recognize the SAB 51 gain at the time. After the conversion of the Class B units to common units on a one-for-one basis in May 2007, PVR no longer had any form of junior securities outstanding. Accordingly, we had recognized a $150.5 million gain in shareholders' equity related to PVR equity issuances from the time of the PVR IPO in October 2001 to May 2007. SAB 51 gains will be recognized with respect to future PVR equity issuances at the time of the equity issuances as long PVR does not have any junior securities outstanding and is not contemplating the issuance of junior securities.

Similarly, we accounted for the PVG IPO as a sale of a minority interest in December 2006. Because the PVR common units had preference over the PVR Class B units with respect to distributions, the gain was not recognized at the time of each PVR equity issuance. When the PVR Class B units converted to common units in May 2007, we recognized a $104.1 million gain to shareholders' equity in accordance with SAB 51.

7. Common Stock and Convertible Note Offerings

In December 2007, we completed the sale of 3,450,000 shares of our common stock in a registered public offering. The net proceeds of the sale were $135.4 million and were used to repay a portion of the outstanding borrowings under our revolving credit facility and for general corporate purposes.

In December 2007, we completed the sale of $230.0 million aggregate principal amount of our convertible senior subordinated notes (the "Convertible Notes") in a registered public offering. The net proceeds of the sale were $222.1 million and were used to repay a portion of the outstanding borrowings under our revolving credit facility and to pay the costs of the Note Hedges and Warrants described below. For a description of the terms of the Convertible Notes, see Note 15, "Long-Term Debt."

In connection with the sale of the Convertible Notes, we entered into convertible note hedge transactions with respect to shares of our common stock (the "Note Hedges") with affiliates of certain of the underwriters of the Convertible Notes (collectively, the "Option Counterparties"). The Note Hedges cover, subject to anti-dilution adjustments, the net shares of our common stock that would be deliverable to converting noteholders in the event of a conversion of the Convertible Notes. We paid an aggregate amount of $18.6 million of the net proceeds from the sale of the Convertible Notes for the cost of the Note Hedges (after such cost is offset by the proceeds of the Warrants described below).

We also entered into separate warrant transactions whereby we sold to the Option Counterparties warrants to acquire, subject to anti-dilution adjustments, approximately 3,982,680 shares of our common stock (the "Warrants") at an exercise price of $74.25 per share. Upon exercise of the Warrants, we have the option to deliver cash or shares of our common stock equal to the difference between the then market price and the strike price of the Warrants.

The Note Hedges and the Warrants are separate contracts entered into by us with the Option Counterparties, are not part of the terms of the Convertible Notes and will not affect the noteholders' rights under the Convertible Notes. The Note Hedges are expected to offset the potential dilution upon conversion of the Convertible Notes in the event that the market value per share of our common stock at the time of exercise is greater than the strike price of the Note Hedges, which corresponds to the initial conversion price of the Convertible Notes and is simultaneously subject to certain adjustments.

If the market value per share of our common stock at the time of conversion of the Convertible Notes is above the strike price of the Note Hedges, the Note Hedges entitle us to receive from the Option Counterparties net shares of our common stock (and cash for any fractional share cash amount) based on the excess of the then current market price of our common stock over the strike price of the Note Hedges. Additionally, if the market price of our common stock at the time of exercise of the Warrants exceeds the strike price of the Warrants, we will owe the Option Counterparties net shares of our common stock (and cash for any fractional share cash amount), not offset by the Note Hedges, in an amount based on the excess of the then current market price of our common stock over the strike price of the Warrants.

8. Suspended Well Costs

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

	2007		2006		2005	
	#Wells	Cost	#Wells	Cost	#Wells	Cost
Balance at beginning of period	1	$1,119	3	$1,670	3	$3,079
Additions pending determination of proved reserves	4	4,336	1	1,119	3	1,670
Reclassifications to wells, equipment and facilities based on the determination of proved reserves	(1)	(1,119)	—	—	—	—
Charged to expense	—	—	(3)	(1,670)	(3)	(3,079)
Balance at end of period	4	$4,336	1	$1,119	3	$1,670

We had no capitalized exploratory drilling costs that had been under evaluation for a period greater than one year as of December 31, 2007, 2006 or 2005.

9. Property and Equipment

The following table summarizes our property and equipment as of December 31, 2007 and 2006:

	December 31,	
	2007	2006
	(in thousands)	
Oil and gas properties		
Proved	$ 1,397,923	$ 945,174
Unproved	127,805	100,008
Total oil and gas properties	1,525,728	1,045,182
Other property and equipment:		
Coal properties	453,484	414,935
Midstream property and equipment	238,040	189,811
Other property and equipment	150,103	55,132
Land	17,753	11,291
Total property and equipment	2,385,108	1,716,351
Accumulated depreciation, depletion and amortization	(486,094)	(357,968)
Net property and equipment	$ 1,899,014	$ 1,358,383

10. Impairment of Oil and Gas Properties

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* we review oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. When we find that the carrying amounts of the properties exceed their estimated undiscounted future cash flows, we adjust the carrying amounts of the properties to their fair value as determined by discounting their estimated future cash flows. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

For the year ended December 31, 2007, we recognized impairment charges of $2.6 million primarily related to changes in estimates of the reserve bases of fields on certain properties in Oklahoma and Texas. For the year ended December 31, 2006, we recognized impairment charges of $8.5 million related to changes in estimates of the reserve bases of fields on certain properties in Louisiana, Texas and West Virginia. For the year ended December 31, 2005, we recognized an impairment charge of $4.8 million related to changes in estimates of the reserve bases of fields on certain properties in Texas.

11. Derivative Instruments

For commodity derivative instruments, we recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). The following table summarizes the effects of commodity derivative activities on our consolidated statements of income for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Income statement caption:			
Natural gas revenues	$ 222	$ 448	$ (14,049)
Oil and condensate revenues	(502)	(457)	(857)
Natural gas midstream revenues	(8,515)	(10,331)	(3,871)
Cost of midstream gas purchased	3,920	8,378	4,859
Derivatives	(47,282)	19,497	(14,885)
Increase (Decrease) in income before minority interest and income taxes	$ (52,157)	$ 17,535	$ (28,803)
Realized and unrealized derivative impact:			
Cash paid for derivative settlements	$ (3,651)	$ (8,947)	$ (19,586)
Unrealized derivative gain (loss)	(48,506)	26,482	(9,217)
Increase (Decrease) in income before minority interest and income taxes	$ (52,157)	$ 17,535	$ (28,803)

Oil and Gas Segment Commodity Derivatives

We utilize costless collar and three-way option derivative contracts to hedge against the variability in cash flows associated with forecasted sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, their use also may limit future revenues from favorable price movements.

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

A three-way option contract consists of a collar contract as described above plus a put option contract sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put option price. By combining the collar contract with the additional put option, we are entitled to a net payment equal to the difference between the floor price of the collar contract and the additional put option price if the settlement price is equal to or less than the additional put option price. If the settlement price is greater than the additional put option price, the result is the same as it would have been with a collar contract only.

This strategy enables us to increase the floor and the ceiling prices of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option.

The fair values of our oil and gas derivative agreements are determined based on third party forward price quotes for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of December 31, 2007. The following table sets forth our positions as of December 31, 2007:

	Average Volume Per Day	Weighted Average Price			Estimated Fair Value
		Additional Put Option	Floor	Ceiling	(in thousands)
Natural Gas Costless Collars	(in MMbtu)		(per MMbtu)		
First quarter 2008	10,000		$9.00	$17.95	$1,511
Second quarter 2008	10,000		$7.50	$9.10	222
Third quarter 2008	10,000		$7.50	$9.10	222
Fourth quarter 2008 (October only)	10,000		$7.50	$9.10	74
Natural Gas Three-Way Options	(in MMbtu)		(per MMbtu)		
First quarter 2008	22,500	$5.44	$8.00	$12.64	1,576
Second quarter 2008	22,500	$5.00	$7.11	$9.09	(65)
Third quarter 2008	22,500	$5.00	$7.11	$9.09	80
Fourth quarter 2008	22,500	$5.44	$7.70	$11.40	581
First quarter 2009	20,000	$5.75	$8.00	$12.80	310
Second quarter 2009	10,000	$5.50	$7.50	$9.10	(95)
Third quarter 2009	10,000	$5.50	$7.50	$9.10	(243)
Settlements to be paid in subsequent period					(331)
Oil and gas segment commodity derivatives – net asset					$3,842

PVR Natural Gas Midstream Segment Commodity Derivatives

PVR utilizes costless collar and swap derivative contracts to hedge against the variability in cash flows associated with forecasted natural gas midstream revenues and cost of midstream gas purchased. PVR also utilizes swap derivative contracts to hedge against the variability in its "frac spread." PVR's frac spread is the spread between the purchase price for the natural gas PVR purchases from producers and the sale price for the NGLs that PVR sells after processing. PVR hedges against the variability in its frac spread by entering into swap derivative contracts to sell NGLs forward at a predetermined swap price and to purchase an equivalent volume of natural gas forward on an MMbtu basis. While the use of derivative instruments limits the risk of adverse price movements, their use also may limit future revenues or cost savings from favorable price movements.

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

The fair values of PVR's derivative agreements are determined based on forward price quotes for the respective commodities as of December 31, 2007. The following table sets forth PVR's positions as of December 31, 2007 for commodities related to natural gas midstream revenues (ethane, propane, natural gasoline and crude oil) and cost of midstream gas purchased (natural gas):

	Average Volume Per Day	Weighted Average Price	Weighted Average Price Collars Floor	Ceiling	Estimated Fair Value (in thousands)
Frac Spreads	**(in MMbtu)**	**(per MMbtu)**			
First quarter 2008 through fourth quarter 2008	7,824	$5.02			$(11,599)
Ethane Sale Swaps	**(in gallons)**	**(per gallon)**			
First quarter 2008 through fourth quarter 2008	34,440	$0.4700			(6,279)
Propane Sale Swaps	**(in gallons)**	**(per gallon)**			
First quarter 2008 through fourth quarter 2008	26,040	$0.7175			(7,372)
Crude Oil Sale Swaps	**(in barrels)**	**(per barrel)**			
First quarter 2008 through fourth quarter 2008	560	$49.27			(8,788)
Natural Gasoline Collars	**(in gallons)**		**(per gallon)**		
First quarter 2008 through fourth quarter 2008	6,300		$1.4800	$1.6465	(953)
Crude Oil Collars	**(in barrels)**		**(per barrel)**		
First quarter 2008 through fourth quarter 2008	400		$65.00	$75.25	(2,669)
Natural Gas Purchase Swaps	**(in MMbtu)**	**(per MMbtu)**			
First quarter 2008 through fourth quarter 2008	4,000	$6.97			1,205
Settlements to be paid in subsequent period					(3,469)
Natural gas midstream segment commodity derivatives – net liability					**$(39,924)**

At December 31, 2007, PVR reported (i) a net derivative liability related to the natural gas midstream segment of $39.9 million and (ii) a loss in accumulated other comprehensive income of $3.6 million, net of the related income tax benefit of $1.9 million, related to derivatives in the natural gas midstream segment for which PVR discontinued hedge accounting in 2006. The $3.6 million loss, net of the related income tax benefit of $1.9 million, will be recorded in earnings through the end of 2008 as the hedged transactions settle.

Interest Rate Swaps

We have entered into interest rate swap agreements (the "Revolver Swaps") to establish fixed rates on a portion of the outstanding borrowings under our revolving credit facility until December 2010. The notional amounts of the Revolver Swaps total $50 million. We will pay a weighted average fixed rate of 5.34% on the notional amount, and the counterparties will pay a variable rate equal to the three-month London Inter Bank Offering Rate (the "LIBOR"). Settlements on the Revolver Swaps are recorded as interest expense. The Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings as interest expense. We reported (i) a derivative liability of $2.1 million at December 31, 2007 and (ii) a loss in accumulated other comprehensive income of $1.4 million, net of the related income tax benefit of $0.7 million, at December 31, 2007 related to the Revolver Swaps. In connection with periodic settlements, we recognized less than $0.1 million in net hedging gains in interest expense for the year ended December 31, 2007. Based upon future interest rate curves at December 31, 2007, we expect to realize $0.7 million of hedging losses within the next 12 months. The amounts that we ultimately realize will vary due to changes in the fair value of open derivative agreements prior to settlement.

PVR Interest Rate Swaps

PVR has entered into interest rate swap agreements (the "PVR Revolver Swaps") to establish fixed rates on a portion of the outstanding borrowings under PVR's revolving credit facility. Until March 2010, the notional amounts of the PVR Revolver Swaps total $160 million. From March 2010 to December 2011, the notional amounts of the PVR Revolver Swaps total $100 million. Until March 2010, PVR will pay a weighted average fixed rate of 4.33% on the notional amount, and the counterparties will pay a variable rate equal to the three-month LIBOR. From March 2010 to December 2011, PVR will pay a weighted average fixed rate of 4.40% on the notional amount, and the counterparties will 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 as interest expense. PVR reported (i) a derivative liability of $1.9 million at December 31, 2007 and (ii) a loss in accumulated other comprehensive income of $1.2 million, net of the related income tax benefit of $0.7 million, at December 31, 2007 related to the PVR Revolver Swaps. In connection with periodic settlements, PVR recognized $0.5 million in net hedging gains, net of the related income tax benefit of $0.2 million, in interest expense for the year ended December 31, 2007. Based upon future interest rate curves at December 31, 2007, PVR expects to realize $0.6 million of hedging losses 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.

12. Accounts Payable and Accrued Liabilities

The following table summarizes our accounts payable and accrued liabilities as of December 31, 2007 and 2006:

	December 31,	
	2007	2006
	(in thousands)	
Drilling costs	$ 19,446	$ 13,279
Royalties	18,032	11,224
Production and franchise taxes	11,935	9,960
Compensation	8,757	6,293
Deferred income	2,958	6,999
Pipeline imbalance	970	685
Interest	3,153	2,149
Other	13,860	15,650
Total accrued liabilities	79,111	66,239
Accounts payable	126,016	88,470
Accounts payable and accrued liabilities	$ 205,127	$ 154,709

13. Asset Retirement Obligations

The following table reconciles the beginning and ending aggregate carrying amount of our asset retirement obligations, which are included in other liabilities on our consolidated balance sheets:

	Year Ended December 31,	
	2007	2006
	(in thousands)	
Balance at beginning of period	$6,747	$4,676
Liabilities incurred	540	1,737
Liabilities settled	(219)	(16)
Accretion expense	805	350
Balance at end of period	$7,873	$6,747

14. Other Liabilities

The following table summarizes our other liabilities as of December 31, 2007 and 2006:

	As of December 31,	
	2007	2006
	(in thousands)	
Deferred income—PVR Coal	$22,243	$6,592
Asset retirement obligation	7,873	6,747
Pension	1,838	1,966
Post-retirement healthcare	4,036	3,891
Environmental	1,466	1,459
Unrecognized tax benefits	8,386	—
Other	8,327	5,348
Total other liabilities	$54,169	$26,003

15. Long-Term Debt

The following table summarizes our long-term debt as of December 31, 2007 and 2006:

	Year Ended December 31,	
	2007	2006
	(in thousands)	
Revolving credit facility—variable rate of 6.7% at December 31, 2007	$122,000	$221,000
Convertible senior subordinated notes	230,000	—
PVR revolving credit facility—variable rate of 6.2% at December 31, 2007	347,700	143,200
PVR senior unsecured notes	64,014	74,846
Total debt	763,714	439,046
Less: Current maturities	(12,561)	(10,832)
Total long-term debt	$751,153	$428,214

We capitalized interest costs amounting to $3.7 million, $3.2 million and $3.5 million in 2007, 2006 and 2005 because the borrowings funded the preparation of unproved properties for their development.

PVR capitalized interest costs amounting to $0.8 million in 2007 because the borrowings funded the construction of natural gas processing plants. PVR capitalized interest costs amounting to $0.3 million in 2006 related to the construction of a coal services facility in October 2006. PVR had no capitalized interest in 2005.

Revolving Credit Facility

As of December 31, 2007, we had $122.0 million outstanding under our $479.0 million revolving credit facility (the "Revolver") that matures in December 2010. The Revolver is secured by a portion of our proved oil and gas reserves. The Revolver is available to us for general purposes, including working capital, capital expenditures and acquisitions, and includes a $20 million sublimit for the issuance of letters of credit. We had outstanding letters of credit of $0.3 million as of December 31, 2007. Effective with the closing of our offering of convertible senior subordinated notes on December 5, 2007, the commitments and borrowing base under the Revolver automatically decreased from $525.0 million to $479.0 million. At the current $479 million limit on the Revolver, and given our outstanding balance of $122.0 million, net of $0.3 million of letters of credit, we could borrow up to $356.6 million. In 2007, we incurred commitment fees of $0.2 million on the unused portion of the Revolver. We capitalized $3.7 million of interest cost incurred in 2007. The Revolver is governed by a borrowing base calculation. Our borrowing base is currently $479 million and is redetermined semi-annually. We have the option to elect interest at (i) the LIBOR plus a Eurodollar margin ranging from 1.00% to 1.75%, based on the ratio of our outstanding borrowings to the borrowing base or (ii) the greater of the prime rate or federal funds rate plus a margin of up to 0.50%. The weighted average interest rate on borrowings outstanding under the Revolver during 2007 was 6.7%.

The financial covenants under the Revolver require us to not exceed specified debt-to-EBITDAX (as defined in the Revolver) and EBITDAX-to-interest expense ratios 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 December 31, 2007, we were in compliance with all of our covenants under the Revolver.

Convertible Senior Subordinated Notes

As of December 31, 2007, we owed $230.0 million under the convertible senior subordinated notes, or the Convertible Notes, outstanding. The Convertible Notes bear interest at a rate of 4.50% per year payable semiannually in arrears on May 15 and November 15 of each year, beginning on May 15, 2008.

The Convertible Notes are convertible into cash up to the principal amount thereof and shares of our common stock, if any, in respect of the excess conversion value, based on an initial conversion rate of 17.3160 shares of common stock per $1,000 principal amount of the Convertible Notes (which is equal to an initial conversion price of approximately $57.75 per share of common stock), subject to adjustment, and, if not converted or repurchased earlier, will mature on November 15, 2012. Holders of Convertible Notes may convert their Convertible Notes at their option prior to the close of business on the business day immediately preceding September 15, 2012 only under the following circumstances: (1) during any fiscal quarter beginning after December 31, 2007 (and only during such fiscal quarter), if the last reported sale price per share of common stock for at least 20 trading days (whether or not consecutive) in the 30 consecutive trading days ending on the last trading day of the immediately preceding fiscal quarter is greater than or equal to 130% of the then applicable conversion price on each such trading day; (2) during the five business day period after any ten consecutive trading day period in which the trading price per $1,000 principal amount of the Convertible Notes for each day of such period was less than 98% of the product of the last reported sale price per share of common stock and the then applicable conversion rate on each such day; or (3) upon the occurrence of certain corporate events set forth in the indenture governing the Convertible Notes. On and after September 15, 2012 until the close of business on the third business day immediately preceding November 15, 2012, holders of the Convertible Notes may convert their Convertible Notes at any time, regardless of the foregoing circumstances.

The holders of the Convertible Notes who convert their Convertible Notes in connection with a make-whole fundamental change, as defined in the indenture governing the Convertible Notes, may be entitled to an increase in the conversion rate as specified in the indenture governing the Convertible Notes. Additionally, in the event of a fundamental change, as defined in the indenture governing the Convertible Notes, the holders of the Convertible Notes may require us to purchase all or a portion of their Convertible Notes at a purchase price equal to 100% of the principal amount of the Convertible Notes, plus accrued and unpaid interest, if any.

The Convertible Notes are our unsecured senior subordinated obligations, ranking junior in right of payment to any of our senior indebtedness and to any of our secured indebtedness to the extent of the value of the assets securing such indebtedness and equal in right of payment to any of our future unsecured senior subordinated indebtedness. The Convertible Notes will rank senior in right of payment to any of our future junior subordinated indebtedness and will structurally rank junior to all existing and future indebtedness of our subsidiaries.

Credit Facility

We have a credit facility with a financial institution, which had no borrowings against it as of December 31, 2007. The facility is effective through August 31, 2008 and is renewable annually. The facility consists of a working capital facility in the amount of $10 million. An additional $10 million facility is available upon bank approval. The interest rate on the working capital facility is equal to the LIBOR plus 1.00% and the interest rate on the additional facility is equal to the LIBOR plus an applicable margin ranging from 1.00% to 1.50%.

PVR Revolving Credit Facility

As of December 31, 2007, PVR had $347.7 million outstanding under its unsecured $450 million revolving credit facility (the "PVR Revolver") that matures in December 2011. The PVR Revolver is available to PVR for general purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. PVR had outstanding letters of credit of $1.6 million as of December 31, 2007. At the current $450 million limit on the PVR Revolver, and given the outstanding balance of $347.7 million, net of $1.6 million of letters of credit, PVR could borrow up to $100.7 million. In 2007, PVR incurred commitment fees of $0.3 million on the unused portion of the PVR Revolver. The interest rate under the PVR Revolver fluctuates based on the ratio of PVR's total indebtedness-to-EBITDA. Interest is payable at a base rate plus an applicable margin of up to 0.75% if PVR selects the base rate borrowing option under the PVR Revolver or at a rate derived from the LIBOR plus an applicable margin ranging from 0.75% to 1.75% if PVR selects the LIBOR-based borrowing option. The weighted average interest rate on borrowings outstanding under the PVR Revolver during 2007 was 6.2%.

The financial covenants under the PVR Revolver require PVR not to exceed specified debt-to-consolidated EBITDA and consolidated EBITDA-to-interest expense ratios. The PVR Revolver prohibits PVR from making distributions to its partners if any potential default, or event of default, as defined in the PVR Revolver, occurs or would result from the 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 its business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. As of December 31, 2007, PVR was in compliance with all of its covenants under the PVR Revolver.

PVR Senior Unsecured Notes

As of December 31, 2007, PVR owed $64.0 million under its senior unsecured notes (the "PVR Notes"). The PVR Notes bear interest at a fixed rate of 6.02% and mature in March 2013, with semi-annual principal and interest payments. The PVR Notes are equal in right of payment with all of PVR's other unsecured indebtedness, including the PVR Revolver. The PVR Notes require PVR to obtain an annual confirmation of its credit rating, with a 1.00% increase in the interest rate payable on the PVR Notes in the event that its credit rating falls below investment grade. In March 2007, PVR's investment grade credit rating was confirmed by Dominion Bond Rating Services. The PVR Notes contain various covenants similar to those contained in the PVR Revolver. As of December 31, 2007, PVR was in compliance with all of its covenants under the PVR Notes.

Debt Maturities

The following table sets forth the aggregate maturities of the principal amounts of long-term debt for the next five years and thereafter:

Year	Aggregate Maturities of Principal Amounts
	(in thousands)
2008	$12,700
2009	14,100
2010	135,400
2011	358,500
2012	239,100
Thereafter	4,300
Total principal	764,100
Less: Terminated interest rate swap	(386)
Total debt, including current maturities	$763,714

16. Income Taxes

Effective January 1, 2007, we adopted FIN 48. The evaluation of whether a tax position is in accordance with FIN 48 is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement.

The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of FIN 48. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized in the financial statements upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings for that fiscal year. The adoption of FIN 48 did not result in a transition adjustment to retained earnings; instead, $8.7 million was reclassified from deferred income taxes to a long-term liability. In the year ended December 31, 2007, we recognized a decrease of $0.5 million in the long-term liability related to tax settlements.

The total liability for unrecognized tax benefits at December 31, 2007 was $9.9 million, including $8.0 million of tax positions which would change the effective tax rate, if recognized. We recognize interest related to unrecognized tax benefits in interest expense, and penalties are included in income tax accrued. For the year ended December 31, 2007, we recognized $0.7 million, in interest and penalties. Prior to adoption of FIN 48, we classified interest on taxes as a component of income tax expense, and penalties were included in income tax expense. We had accrued interest and penalties of $3.4 million as of December 31, 2007 and $2.7 million as of January 1, 2007. Tax years from 2004 forward remain open for examination by the Internal Revenue Service. Tax years from 2003 forward remain open for state jurisdictions.

We are currently evaluating the filing status of a subsidiary in a state. If management and the state's taxing authority determine that the subsidiary's income is taxable in that state, it is reasonably possible that a payment of approximately $1.4 million will be made by the end of 2008. We classified $1.4 million of the total liability for unrecognized tax benefits as a current liability in income taxes payable on the balance sheet at December 31, 2007. This current liability represents our best estimate of the change in unrecognized tax benefits that we expect to occur within the next 12 months.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2007
	(in millions)
Beginning of year (adoption adjustment)	$8,737
Additions based on tax positions related to the current year	1,659
Settlements	(544)
Balance at end of year	9,852
Less: current portion	(1,466)
Long-term portion	$8,386

The following table summarizes our provision for income taxes from continuing operations for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Current income taxes			
Federal	$ 6,212	$ 11,710	$ 21,708
State	949	258	1,867
Total current	7,161	11,968	23,575
Deferred income taxes			
Federal	19,797	29,419	12,007
State	3,543	8,601	5,087
Total deferred	23,340	38,020	17,094
Total income tax expense	$ 30,501	$ 49,988	$ 40,669

The following table reconciles the difference between the taxes computed by applying the statutory tax rate to income from operations before income taxes and our reported income tax expense for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,					
	2007		2006		2005	
Computed at federal statutory tax rate	$ 28,441	35.0%	$ 44,063	35.0%	$ 35,966	35.0%
State income taxes, net of federal income tax benefit	3,275	4.0%	5,391	4.2%	4,341	4.2%
Other, net	(1,215)	(1.5%)	534	0.5%	362	0.4%
Total income tax expense	$ 30,501	37.5%	$ 49,988	39.7%	$ 40,669	39.6%

The following table summarizes the principal components of our net deferred income tax liability as of December 31, 2007 and 2006:

	As of December 31,	
	2007	2006
	(in thousands)	
Deferred tax liabilities:		
Property and equipment	$229,557	$187,081
Fair value of derivative instruments	—	3,285
Other	997	5,119
Total deferred tax liabilities	230,554	195,485
Deferred tax assets:		
Fair value of derivative instruments	30,015	—
Deferred income—coal properties	9,836	5,331
Pension and post-retirement benefits	4,877	2,857
Stock-based compensation	3,428	2,054
Net operating loss carryforwards	459	2,219
Other	4,262	4,644
Total deferred tax assets	52,877	17,105
Net deferred tax liability	$177,677	$178,380

In assessing our deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Among other items, we consider the scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies. As of December 31, 2007 and 2006, no valuation allowance had been recorded because we estimated that it was more likely than not that all of our deferred tax assets would be realized.

In June 2006, we acquired 100% of the common stock of Crow Creek (see Note 4). As a result, we acquired federal and state tax net operating loss carryforwards ("NOLs") which, if unused, will expire between 2022 and 2026. In addition to the carryforward period, these acquired NOLs are subject to other restrictions and limitations, including Section 382 of the Internal Revenue Code, which impact their ultimate realizability. As of December 31, 2007, we had approximately $1.3 million of federal regular tax NOLs. We did not record any valuation allowance with respect to these NOLs because we estimated that it was more likely than not that these NOLs would be utilized before they expire.

17. Employee Benefit Plans

401(k) Plan

We sponsor a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 50% of their base salaries. After the employee meets certain service requirements, we match each employee's contributions up to 6% of the employee's base salary. Our contributions to the 401(k) Plan were approximately $1.4 million, $1.1 million and $0.6 million for the years ended December 31, 2007, 2006 and 2005.

Pension Plans and Other Post-Retirement Benefits

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

On December 31, 2006, we adopted the recognition and disclosure provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. SFAS No. 158 required us to recognize the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligations) of our pension and other post-retirement benefit plans on our consolidated statement of financial position at December 31, 2006, with a corresponding adjustment to accumulated other comprehensive income

("AOCI"), net of tax. The measurement dates used to determine the pension and post-retirement healthcare plans benefit obligations are December 31, 2007 and 2006.

The following table provides the amounts included in AOCI at December 31, 2007 that have not yet been recognized in net periodic pension cost:

	Unrecognized Costs As of December 31, 2007	
	Pension	Post-Retirement Healthcare
	(in thousands)	
Unrecognized prior service costs	$ 5	$ 671
Tax effect	(2)	(235)
Unrecognized prior service costs, net of tax	3	436
Actuarial loss	594	1,457
Tax effect	(208)	(510)
Actuarial loss, net of tax	386	947
Total amount recognized in AOCI, net of tax	$389	$1,383

The following table provides a reconciliation of the beginning and ending balances of the portion of AOCI that relates to the pension and post-retirement healthcare plans for the years ended December 31, 2007, 2006 and 2005:

	Pension			Post-Retirement Healthcare		
	2007	2006	2005	2007	2006	2005
	(in thousands)					
Beginning balance in AOCI	$(429)	$(401)	$(417)	$(1,329)	$ —	$—
Change in minimum pension liability, before adoption of SFAS No. 158	—	(19)	16	—	—	—
Effect on comprehensive income	—	(19)	16	—	—	—
Adoption of SFAS No. 158:						
Prior service cost	*	(7)	*	*	(493)	*
Transition obligation	*	(2)	*	*	(836)	*
Adjustments to adopt SFAS No. 158	—	(9)	—	—	(1,329)	—
Post SFAS No. 158 adoption:						
Actuarial gain (loss)	11	*	*	(187)	*	*
Amortization of actuarial loss	23	*	*	75	*	*
Amortization of prior service cost	4	*	*	58	*	*
Amortization of transition obligation	2	*	*	—	*	*
Adjustments after adoption of SFAS No. 158	40	—	—	(54)	—	—
Ending balance in AOCI	$(389)	$(429)	$(401)	$(1,383)	$(1,329)	$—

* Not applicable due to change in method of accounting for deferred benefit and other post-retirement plans.

The following table provides the transition obligation, prior service cost and actuarial loss included in AOCI and expected to be recognized in net periodic pension cost during 2008:

	Costs Expected to be Recognized for the Year Ending December 31, 2008	
	Pension	Post-Retirement Healthcare
	(in thousands)	
Amortization of prior service costs	$5	$88
Tax effect	(2)	(31)
Amortization of prior service costs, net of tax	3	57
Amortization of actuarial loss	40	94
Tax effect	(14)	(33)
Amortization of actuarial loss, net of tax	26	61
Total amount expected to be recognized in net periodic pension cost, net of tax	$29	$118

The following table provides a reconciliation of the beginning and ending balances of the benefit obligations and fair value of plan assets for the years ended December 31, 2007 and 2006, and the funded status at December 31, 2007 and 2006:

	Pension		Post-Retirement Healthcare	
	2007	2006	2007	2006
	(in thousands)			
Change in benefit obligation:				
Obligation—beginning of year	$2,203	$2,242	$4,302	$4571
Service cost	—	—	22	27
Interest cost	122	127	257	243
Benefits paid	(243)	(232)	(419)	(426)
Actuarial loss (gain)	(17)	66	314	(113)
Obligation—end of year	2,065	2,203	4,476	4302
Change in fair value of plan assets:				
Fair value—beginning of year	—	—	—	—
Employer contributions	243	232	392	401
Participant contributions	—	—	27	25
Benefits paid	(243)	(232)	(419)	(426)
Fair value—end of year	—	—	—	—
Funded status—end of year	$(2,065)	$(2,203)	$(4,476)	$(4,302)
Accumulated benefit obligation—end of year	$(2,065)	$(2,203)	$(4,476)	$(4,302)

The underfunded status of the pension and post-retirement healthcare plans of $2.1 million and $4.5 million as of December 31, 2007 has been recognized as a liability on our consolidated statements of financial position. The following table provides the amounts recognized on our consolidated statements of financial position at December 31, 2007 and 2006:

	Pension		Post-Retirement Healthcare	
	2007	2006	2007	2006
	(in thousands)			
Accounts payable and accrued liabilities	$(227)	$(237)	$(440)	$(411)
Other long-term liabilities	(1,838)	(1,966)	(4,036)	(3,891)
Deferred income tax asset	210	231	745	716
Accumulated other comprehensive loss	389	429	1,383	1,329

The following table provides the components of net periodic benefit cost for the plans for the years ended December 31, 2007 and 2006:

	Pension		Post-Retirement Healthcare	
	2007	2006	2007	2006
	(in thousands)			
Service cost	$—	$—	$22	$27
Interest cost	122	127	257	243
Amortization of prior service cost	6	6	89	89
Amortization of transition obligation	3	4	—	—
Recognized actuarial loss	36	36	116	81
Net periodic benefit cost	$167	$173	$484	$440

We used an assumed discount rate of 6.00% in 2007 and 5.70% in 2006 for the measurement of our pension and post-retirement healthcare benefit obligations. We base the discount rates on investments with cash flows yields that match the timing and expected benefit payments of our plans.

For measurement purposes, a 9.5% annual rate increase in the per capita cost of covered health care benefits was assumed for 2007. The rate is assumed to decrease gradually to 5% for 2014 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for post-retirement benefits. A 1% change in assumed health care cost trend rates would have the following effects for 2007:

	One Percent Increase	One Percent Decrease
	(in thousands)	
Effect on total of service and interest cost components	$ 9	$ (9)
Effect on post-retirement benefit obligation	$157	$(153)

We expect to contribute $0.2 million to the pension plan and $0.5 million to the post-retirement healthcare plan in 2008.

The following table sets forth the benefit payments, which reflect expected future service, as appropriate, expected to be paid in the years indicated:

Year	Pension	Post-Retirement Healthcare
	(in thousands)	
2008	$227	$453
2009	242	463
2010	235	474
2011	221	476
2012	209	479
2013-17	901	2,154

18. Earnings per Share

The following table provides a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands, except per share data)		
Net income	$ 50,754	$ 75,909	$ 62,088
Weighted average shares, basic	38,061	37,362	37,092
Effective of dilutive securities:			
Stock options	297	370	372
Weighted average shares, diluted	38,358	37,732	37,464
Net income per share, basic	$ 1.33	$ 2.03	$ 1.67
Net income per share, diluted	$ 1.32	$ 2.01	$ 1.66

Options with an exercise price exceeding the average price of the underlying securities are not considered to be dilutive and are not included in calculation of the denominator for diluted earnings per share for the years ended December 31, 2007, 2006 and 2005. The Convertible Notes (see Note 15) issued in December 2007 have not met the criteria for conversion. Therefore, the Convertible Notes are not dilutive and are not included in the calculation of the denominator for diluted earnings per share for the year ended December 31, 2007.

19. Share-Based Payments

Stock Compensation Plans

Adoption of SFAS No. 123(R). 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. At December 31, 2007, there were approximately 391,008 and 1,984,752 shares available for issuance to directors and employees pursuant to the Stock Compensation Plans. 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 consolidated 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 year ended December 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 years ended December 31, 2007, 2006 and 2005, we recognized $4.1 million, $2.8 million and $0.7 million of compensation expense related to the Stock Compensation Plans. The total income tax benefit recognized in our consolidated statements of income for the Stock Compensation Plans was $1.6 million, $1.1 million and $0.3 million for the years ended December 31, 2007, 2006 and 2005.

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 are $1.4 million and $0.8 million lower for the year ended December 31, 2006 than if we had continued to account for share-based compensation under Opinion No. 25. Basic and diluted earnings per share are $0.03 and $0.02 lower for the year ended December 31, 2006 than if we had continued to account for share-based compensation under Opinion No. 25.

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 our consolidated 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 $2.6 million excess tax benefit classified as a financing cash inflow for the year ended December 31, 2006 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 our net income and earnings per share as if we had applied the fair value recognition provision of SFAS No. 123 to options granted under our stock option plans for the year ended December 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.

	Year Ended December 31, 2005 (in thousands, except per share data)
Net income, as reported	$62,088
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	1,008
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(1,751)
Pro forma net income	$61,345
Earnings per share	
Basic—as reported	$1.67
Basic—pro forma	$1.65
Diluted—as reported	$1.66
Diluted—pro forma	$1.64

Stock Options. The exercise price of all options granted under the Stock Compensation Plans is equal to 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 ten years following the date of grant. Options vest upon terms established by the compensation and benefits committee of our board of directors. In addition, all options will vest upon a change of control of us, 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 after reaching age 62 and providing ten consecutive years of service, 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 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.

	2007	**2006**	**2005**
Expected volatility	30.0% to 38.5%	20.9% to 31.5%	26.4%
Dividend yield	0.51% to 0.63%	0.60% to 0.71%	0.81% to 1.10%
Expected life	3.5 to 4.6 years	3.5 to 4.6 years	4 years
Risk-free interest rate	3.86% to 4.72%	4.59% to 5.01%	3.88% to 4.04%

The following table summarizes activity for our most recent fiscal year with respect to common stock options awarded:

	Shares Under Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
			(in years)	(in thousands)
Outstanding at January 1, 2007	1,333,976	$19.47		
Granted	419,030	35.33		
Exercised	(368,277)	14.41		
Forfeited	(38,312)	33.61		
Outstanding at December 31, 2007	1,346,417	$25.39	7.4	$26,347
Exercisable at December 31, 2007	617,605	$16.35	5.9	$17,672

The weighted-average grant-date fair value of options granted during the years ended December 31, 2007, 2006 and 2005 was $9.83, $7.17 and $6.14 per option. The total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005 was $10.0 million, $7.4 million and $3.9 million.

The following table summarizes the status of our nonvested options as of December 31, 2007, and changes during the year then ended:

	Nonvested Options	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2007	666,938	$6.27
Granted	419,030	9.83
Vested	(318,845)	5.49
Forfeited	(38,312)	8.58
Nonvested at December 31, 2007	728,812	$8.54

As of December 31, 2007, we had $4.3 million of total unrecognized compensation cost related to nonvested stock options. We expect that cost to be recognized over a weighted-average period of 0.9 years. The total grant-date fair value of stock options that vested in 2007, 2006 and 2005 was $1.8 million, $0.8 million and $0.8 million.

Cash received from the exercise of stock options in 2007 was $9.2 million. The actual tax benefit realized for the tax deductions from option exercises was $3.5 million for the year ended December 31, 2007.

Restricted Stock. Restricted stock vests upon terms established by the compensation and benefits committee of our board of directors. In addition, all restricted stock will vest upon a change of control of us. If a grantee's employment terminates for any reason other than death, disability or retirement, the grantee's restricted stock will be automatically forfeited. If a grantee's employment terminates by reason of death, disability or retirement, the grantee's restricted stock will automatically vest unless otherwise determined by the compensation and benefits committee. Except as specified by the compensation and benefits committee, a grantee shall be entitled to receive any dividends declared on our common stock. Restricted stock vests over a three-year period, with either one-third vesting in each year or 25% vesting after the first year, 25% vesting after the second year and 50% vesting after the third year. We recognize compensation expense on a straight-line basis over the vesting period.

The following table summarizes the status of our nonvested restricted stock as of December 31, 2007, and changes during the year then ended:

	Nonvested Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2007	51,080	$29.90
Granted	17,056	35.21
Vested	(18,788)	29.40
Forfeited	—	—
Nonvested at December 31, 2007	49,348	$31.92

At December 31, 2007, we had $1.0 million of total unrecognized compensation cost related to nonvested restricted stock. We expect that cost to be recognized over a weighted-average period of 0.7 years. The total grant-date fair value of restricted stock that vested in 2007 and 2006 was $0.6 million and $0.4 million. No restricted stock vested prior to 2006.

Deferred Common Stock Units. A portion of the compensation paid to non-employee members of our board of directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, which vests immediately upon issuance and is available to the holder upon termination or retirement from our board of directors. Deferred common stock units awarded to directors receive all cash or other dividends we pay on account of shares of our common stock.

The following table summarizes activity for the most recent fiscal year with respect to deferred common stock units awarded:

	Deferred Common Stock Units	Weighted Average Grant-date Fair Value
Outstanding at January 1, 2007	46,986	$29.90
Granted	15,468	$39.63
Converted to common stock	(10,482)	$30.44
Outstanding at December 31, 2007	51,972	$30.94

The aggregate intrinsic value of deferred common stock units converted to shares of common stock in 2007 was $0.3 million. No deferred common stock units converted to shares of common stock in 2006 or 2005.

In accordance with EITF Issue No. 97-14, *Accounting for Deferred Compensation Arrangements Where Amounts Earned Are Held in a Rabbi Trust and Invested,* we recorded a $1.6 million, $1.3 million and $0.6 million deferred compensation obligation in shareholders' equity at December 31, 2007, 2006 and 2005 and a corresponding amount for treasury stock.

PVG Common Units. In connection with the PVG IPO in December 2006, we granted 39,500 PVG common units at a weighted average grant-date fair value of $18.73 per unit to officers and employees. The PVG common units vested on the date of grant but bear a restrictive legend. We recognized compensation expense of $0.7 million in 2006 related to the grant of PVG common units.

PVG Long-Term Incentive Plan

PVG's general partner has adopted a long-term incentive plan. PVG's long-term incentive plan permits the grant of awards covering an aggregate of 300,000 PVG common units to employees and directors of PVG's general partner and employees of its affiliates who perform services for PVG. Awards under the PVG long-term incentive plan can be in the form of PVG common units, restricted PVG units, PVG unit options, phantom PVG units and deferred PVG common units. The PVG long-term incentive plan is administered by the compensation and benefits committee of the board of directors of PVG's general partner. PVG reimburses its general partner for payments made pursuant to the PVG long-term incentive plan and recognizes compensation expense over the vesting period of the award.

PVG recognizes compensation expense related to the granting of common units and deferred common units and the vesting of restricted units granted under PVG's long-term incentive plan. PVG recognized compensation expense related to the PVG long-term incentive plan of $0.4 million for the year ended December 31, 2007. PVG granted no awards under and recognized no compensation expense related to the PVG long-term incentive plan prior to 2007.

Deferred PVG Common Units. A portion of the compensation to the non-employee directors of PVG's general partner is paid in deferred PVG common units. Each deferred PVG common unit represents one PVG common unit, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of our general partner. We granted 13,396 deferred PVG common units in 2007 at a weighted average grant date fair value of $27.30 per unit.

PVR Long-Term Incentive Plan

PVR's general partner has adopted a long-term incentive plan. PVR's long-term incentive plan permits the grant of awards covering an aggregate of 600,000 PVR common units to employees and directors of PVR's general partner and employees of its affiliates who perform services for PVR. Awards under the PVR long-term incentive plan can be in the form of PVR common units, restricted PVR units, PVR unit options, phantom PVR units and deferred PVR common units. The PVR long-term incentive plan is administered by the compensation and benefits committee of the board of directors of PVR's general partner. PVR reimburses its general partner for payments made pursuant to the PVR long-term incentive plan and recognizes compensation expense based on the fair value of the awards over the vesting period.

PVR recognizes compensation expense related to the granting of common units and deferred common units and the vesting of restricted units granted under PVR's long-term incentive plan. PVR recognized compensation expense related to the PVR long-term incentive plan of $2.4 million, $1.9 million and $1.4 million for the years ended December 31, 2007, 2006 and 2005.

PVR Common Units. PVR's general partner granted 1,183 common units at a weighted average grant-date fair value of $27.09 per unit to non-employee directors in 2007. PVR's general partner granted 1,795 common units at a weighted average grant-date fair value of $26.01 per unit to non-employee directors in 2006. PVR's general partner granted 876 common units at a weighted average grant-date fair value of $25.36 per unit to non-employee directors in 2005.

Restricted PVR Units. Restricted PVR units vest upon terms established by the compensation and benefits committee. In addition, all restricted PVR units will vest upon a change of control of PVR's general partner or Penn Virginia. If a grantee's employment with, or membership on the board of directors of, PVR's general partner terminates for any reason, the grantee's unvested restricted PVR units will be automatically forfeited unless, and to the extent that, the compensation and benefits committee provides otherwise. Distributions payable with respect to restricted PVR units may, in the compensation and benefits committee's discretion, be paid directly to the grantee or held by PVR's general partner and made subject to a risk of forfeiture during the applicable restriction period. Restricted PVR units generally vest over a three-year period, with one-third vesting in each year.

The following table summarizes the status of nonvested restricted PVR units as of December 31, 2007, and changes during the year then ended:

	Nonvested Restricted Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2007	114,214	$27.85
Granted	87,033	26.88
Vested	(43,049)	27.54
Forfeited	(1,267)	27.65
Nonvested at December 31, 2007	156,931	$27.40

At December 31, 2007, PVR had $2.7 million of total unrecognized compensation cost related to nonvested restricted PVR units. PVR expects to reimburse its general partner for that cost over a weighted-average period of 0.9 years. The total grant-date fair value of restricted PVR units that vested in 2007, 2006 and 2005 was $1.2 million, $2.2 million and $0.4 million.

Deferred PVR Common Units. A portion of the compensation to the non-employee directors of PVR's general partner is paid in deferred PVR common units. Each deferred PVR common unit represents one PVR common unit, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of PVR's general partner. At December 31, 2006, 39,009 deferred PVR common units were outstanding at a weighted average grant-date fair value of $25.26 per common unit. PVR's general partner granted 22,209 deferred PVR common units in 2007 at a weighted average grant-date fair value of $26.43. At December 31, 2007, 61,218 deferred PVR common units were outstanding at a weighted average grant-date fair value of $25.58. The aggregate intrinsic value of deferred PVR common units converted to PVR common units in 2006 was $0.2 million. No deferred PVR common units converted to PVR common units in 2007 or 2005.

20. Other Comprehensive Income

Comprehensive income represents changes in shareholders' equity during the reporting period, including net income and charges directly to shareholders' equity which are excluded from net income. The following table sets forth the components of comprehensive income for the years ended December 31, 2007, 2006 and 2005:

	Cash Flow Hedges	Pension and Postretirment Healthcare	Total
		(in thousands)	
Hedging unrealized loss, net of tax of ($1,432)	$ (2,659)	$ -	$ (2,659)
Hedging reclassification adjustment, net of tax of $1,449	2,691	-	2,691
Pension adjustment, net of tax of $21	-	39	39
Postretirement healthcare adjustment, net of tax of ($29)	-	(53)	(53)
Other comprehensive income for the year ended December 31, 2007	$ 32	$ (14)	$ 18
Hedging unrealized loss, net of tax of $321	$ 597	$ -	$ 597
Hedging reclassification adjustment, net of tax of $335	622	-	622
Pension adjustment, net of tax of $10	-	(19)	(19)
Other comprehensive income for the year ended December 31, 2006	$ 1,219	$ (19)	$ 1,200
Hedging unrealized loss, net of tax of $8,726	$ (16,206)	$ -	$ (16,206)
Hedging reclassification adjustment, net of tax of $4,897	9,094	-	9,094
Pension plan adjustment, net of tax of $9	-	16	16
Other comprehensive income for the year ended December 31, 2005	$ (7,112)	$ 16	$ (7,096)

21. Commitments and Contingencies

Rental Commitments

Operating lease rental expense in the years ended December 31, 2007, 2006 and 2005 was $16.0 million, $10.0 million and $5.8 million. The following table sets forth our minimum rental commitments for the next five years under all non-cancelable operating leases in effect at December 31, 2007:

Year	Minimum Rental Commitments
	(in thousands)
2008	$8,641
2009	5,833
2010	3,375
2011	2,848
2012	1,827
Total minimum payments	$22,524

Our rental commitments primarily relate to equipment and building leases and leases of coal reserve-based properties which PVR subleases, or intends to sublease, to third parties. The obligation with respect to leased properties which PVR subleases expires when the property has been mined to exhaustion or the lease has been canceled. The timing of mining by third party operators is difficult to estimate due to numerous factors. We believe that the future rental commitments cannot be estimated with certainty; however, based on current knowledge and historical trends, PVR believes that it will incur $0.9 million in rental commitments annually until the reserves have been exhausted.

Drilling Commitments

We have agreements to purchase oil and gas well drilling services from third parties for terms ranging from two to three years. The agreements include early termination provisions that would require us to pay penalties if we terminate the agreements prior to the end of original terms. The amount of penalty is based on the number of days remaining in the contractual term and declines as time passes. As of December 31, 2007, the penalty amount would have been $10.6 million if we had terminated our agreements on that date. Our management intends to utilize drilling services under these agreements for the full terms and has no plans to terminate the agreements early. The following table sets forth our obligation for drilling commitments in effect at December 31, 2007 for the next two years:

Year	Drilling Commitments
	(in thousands)
2008	$8,395
2009	8,395
Total drilling commitments	$16,790

Oil and Gas Segment Firm Transportation Commitments

In 2004, we entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to 10 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion. The following table set forth our obligation for firm transportation commitments in effect at December 31, 2007 for the next five years and thereafter:

Year	Firm Transportation Commitments
	(in thousands)
2008	$1,160
2009	1,081
2010	1,081
2011	1,081
2012	1,081
Thereafter	2,072
Total firm transportation commitments	$7,556

PVR Natural Gas Midstream Segment Firm Transportation Commitments

As of December 31, 2007, PVR's firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to seven years. The contracts require PVR to pay transportation demand charges regardless of the amount of pipeline capacity PVR uses. PVR may sell excess capacity to third parties at its discretion. The following table set forth PVR's obligation for firm transportation commitments in effect at December 31, 2007 for the next five years and thereafter:

Year	Firm Transportation Commitments
	(in thousands)
2008	$11,838
2009	4,745
2010	6,168
2011	5,694
2012	4,508
Thereafter	7,354
Total firm transportation commitments	$40,307

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, our management believes that 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.

PVR's operations and those of its lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of PVR'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 PVR against any and all future environmental liabilities. PVR regularly visits its coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. PVR's management believes that its operations and those of its lessees comply with existing laws and regulations and does not expect any material impact on its financial condition or results of operations.

As of December 31, 2007 and 2006, PVR's environmental liabilities included $1.5 million and $1.6 million, which represents PVR's best estimate of the liabilities as of those dates related to its coal and natural resource management and natural gas midstream businesses. PVR 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.

Mine Health and Safety Laws

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

22. 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 officers. This group routinely reviews and makes operating and resource allocation decisions among our oil and gas operations and PVR's coal and natural resource management 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.
- PVR Coal and Natural Resource Management—management and leasing of coal properties and subsequent collection of royalties; other land management activities such as selling standing timber and real estate rentals; leasing of fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants; and collection of oil and gas royalties.
- PVR Natural Gas Midstream—natural gas processing, natural gas gathering and other related services.

The following table presents a summary of certain financial information relating to our segments as of and for the years ended December 31, 2007, 2006 and 2005:

	Oil and Gas	PVR Coal and Natural Resource Management	PVR Natural Gas Midstream	Corporate and Other	Consolidated
			(in thousands)		
As of and for the Year Ended December 31, 2007					
Revenues (2)	$ 304,790	$ 110,847	$ 436,257	$ 1,056	$ 852,950
Intersegment revenues (1)	(1,549)	792	1,549	(792)	-
Operating costs and expenses	112,035	20,138	370,070	28,560	530,803
Depreciation, depletion and amortization (3)	87,223	22,463	18,822	1,015	129,523
Operating income (loss)	$ 103,983	$ 69,038	$ 48,914	$ (29,311)	192,624
Interest expense					(37,419)
Interest income and other					3,651
Derivatives					(47,282)
Income before minority interest and taxes					$ 111,574
Total assets	$ 1,287,359	$ 580,093	$ 320,413	$ 65,596	$ 2,253,461
Equity investments	-	25,580	60	-	25,640
Additions to property and equipment and acquisitions (4)	512,473	146,960	47,082	6,995	713,510
As of and for the Year Ended December 31, 2006					
Revenues	$ 236,238	$ 112,189	$ 404,628	$ 874	$ 753,929
Intersegment revenues (1)	(282)	792	282	(792)	-
Operating costs and expenses	94,886	19,138	358,440	16,716	489,180
Depreciation, depletion and amortization	56,237	20,399	17,094	487	94,217
Operating income (loss)	$ 84,833	$ 73,444	$ 29,376	$ (17,121)	170,532
Interest expense					(24,832)
Interest income and other					3,718
Derivatives					19,497
Income before minority interest and taxes					$ 168,915
Total assets	$ 885,550	$ 409,709	$ 304,314	$ 33,576	$ 1,633,149
Equity investments	-	25,295	60	-	25,355
Additions to property and equipment and acquisitions (5)	331,551	92,697	37,015	3,676	464,939
As of and for the Year Ended December 31, 2005					
Revenues	$ 226,819	$ 95,359	$ 350,593	$ 1,093	$ 673,864
Intersegment revenues (1)	-	396	-	(396)	-
Operating costs and expenses	85,454	16,121	321,509	11,826	434,910
Depreciation, depletion and amortization	45,885	17,890	12,738	424	76,937
Operating income (loss)	$ 95,480	$ 61,744	$ 16,346	$ (11,553)	162,017
Interest expense					(15,318)
Interest income and other					1,332
Derivatives					(14,885)
Income before minority interest and taxes					$ 133,146
Total assets	$ 576,634	$ 372,322	$ 285,557	$ 17,033	$ 1,251,546
Equity investments	-	26,612	60	-	26,672
Additions to property and equipment and acquisitions (6)	171,301	112,497	206,811	350	490,959

(1) Represents agent fees paid by the oil and gas segment to the PVR natural gas midstream segment for marketing certain natural gas production and rail car rental fees paid by a corporate affiliate to the PVR coal and natural resource management segment.

(2) PVR oil and gas segment excludes $31 million of gain related to the sale of royalty interests to PVR.

(3) PVR coal and natural resource management segment excludes $0.2 million of depletion related to the royalty interests purchased from us.

(4) PVR coal and natural resource management segment in 2007 includes an $11.5 million lease receivable associated with the acquisition of fee ownership and lease rights to coal reserves in western Kentucky and excludes $31 million of royalty interests that PVR purchased from us.

(5) Oil and gas segment includes deferred tax assets of $32.3 million and acquisition of net liabilities other than property or

equipment of $29.1 million related to the acquisition of Crow Creek. PVR coal and natural resource management segment includes acquisition of assets other than property or equipment of $1.2 million.

(6) PVR coal and natural resource management segment excludes noncash expenditures of $14.4 million related to acquisitions.

Operating income is equal to total revenues less cost of midstream gas purchased, operating costs and expenses and depreciation, depletion and amortization. Operating income does not include certain other income items, interest expense, interest income and income taxes. Identifiable assets are those assets used in our operations in each segment.

For the year ended December 31, 2007, one customer of the PVR natural gas midstream segment accounted for $109.2 million, or 13%, of our total consolidated net revenues. In June 2005, one of our subsidiaries began leasing railcars from a subsidiary of PVR. Intercompany railcar rental revenues were $0.8 million in 2007 and are included in the PVR coal and natural resource management segment. The offsetting railcar rental expense and the elimination of the revenue and expense are included in the corporate and other column of the preceding table. In 2007, the oil and gas segment paid $0.5 million to the PVR natural gas midstream segment for marketing a portion of the oil and gas segment's natural gas production.

For the year ended December 31, 2006, one customer of the PVR natural gas midstream segment accounted for $129.1 million, or 17%, of our total consolidated net revenues. Intercompany railcar rental revenues were $0.8 million in 2006 and are included in the PVR coal and natural resource management segment. The offsetting railcar rental expense and the elimination of the revenue and expense are included in the corporate and other column of the preceding table. In 2006, the oil and gas segment paid $0.4 million to the PVR natural gas midstream segment for marketing a portion of the oil and gas segment's natural gas production. The marketing agreement was effective September 1, 2006.

For the year ended December 31, 2005, two customers of the PVR natural gas midstream segment accounted for $81.9 million and $77.1 million, or 12% and 11%, of our total consolidated net revenues. Intercompany railcar rental revenues were $0.4 million in 2005 and are included in the PVR coal and natural resource management segment. The offsetting railcar rental expense and the elimination of the revenue and expense are included in the corporate and other column of the preceding table.

Supplemental Quarterly Financial Information (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share data)			
2007				
Revenues	$ 186,270	$ 222,398	$ 215,758	$ 228,524
Operating income	$ 38,539	$ 57,074	$ 51,884	$ 45,127
Net income	$ 4,403	$ 23,878	$ 17,114	$ 5,359
Net income per share (1):				
Basic	$ 0.12	$ 0.63	$ 0.45	$ 0.14
Diluted	$ 0.11	$ 0.63	$ 0.45	$ 0.14
Weighted average shares outstanding (1):				
Basic	37,594	37,750	37,898	38,805
Diluted	38,316	38,055	38,213	39,157
2006				
Revenues	$ 200,907	$ 179,150	$ 188,393	$ 185,479
Operating income	$ 48,666	$ 49,939	$ 44,644	$ 27,283
Net income	$ 24,108	$ 18,217	$ 22,881	$ 10,703
Net income per share (1):				
Basic	$ 0.65	$ 0.49	$ 0.61	$ 0.29
Diluted	$ 0.64	$ 0.48	$ 0.61	$ 0.28
Weighted average shares outstanding (1):				
Basic	37,304	37,354	37,358	37,492
Diluted	37,746	37,826	37,790	37,872

(1) The sum of the quarters may not equal the total of the respective year's net income per share due to changes in the weighted average shares outstanding throughout the year. The net income per share and weighted average shares outstanding have been adjusted to reflect the two-for-one stock split in June 2007. See Note 5, "Stock Split."

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following supplemental information regarding the oil and gas producing activities is presented in accordance with the requirements of the SEC and SFAS No. 69, *Disclosures about Oil and Gas Producing Activities.* The amounts shown include our net working and royalty interest in all of our oil and gas operations.

Capitalized Costs Relating to Oil and Gas Producing Activities

	December 31, 2007	December 31, 2006	December 31, 2005
		(in thousands)	
Proved properties	$ 280,742	$ 213,017	$ 126,286
Unproved properties	127,805	100,008	66,727
Wells, equipment and facilities	1,090,105	706,860	502,877
Support equipment	4,493	2,713	4,088
	1,503,145	1,022,598	699,978
Accumulated depreciation and depletion	(334,688)	(245,463)	(191,860)
Net capitalized costs (1)	$ 1,168,457	$ 777,135	$ 508,118

(1) Net capitalized costs of $19.6 million at December 31, 2007, $19.9 million at December 31, 2006 and $16.4 million at December 31, 2005 relating to a transmission pipeline and compression in the Appalachian Basin placed into service from 2004 to 2006 were excluded from net capitalized costs.

In accordance with SFAS No. 143, during 2007, 2006 and 2005, an additional $0.5 million, $1.4 million and $0.4 million were added to the cost basis of oil and gas wells for wells drilled.

Costs Incurred in Certain Oil and Gas Activities

	December 31, 2007	December 31, 2006	December 31, 2005
		(in thousands)	
Proved property acquisition costs	$ 88,174	$ 72,724	$ -
Unproved property acquisition costs	18,817	56,563	26,360
Exploration costs	46,425	51,665	30,335
Development costs and other (1)	367,012	184,675	109,066
Total costs incurred	$ 520,428	$ 365,627	$ 165,761

(1) Development costs of $5.1 million in 2006 and $3.8 million in 2005 relating to a transmission pipeline and compression in the Appalachian Basin placed into service during from 2004 to 2006 were excluded from costs incurred.

Costs for the year ended December 31, 2006 include deferred income taxes of $32.3 million provided for the book versus tax basis difference related to the acquired Crow Creek properties.

Results of Operations for Oil and Gas Producing Activities

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

	December 31,		
	2007	2006	2005
		(in thousands)	
Revenues	$ 290,286	$ 234,156	$ 226,219
Production expenses	65,130	39,681	30,940
Exploration expenses	28,608	34,330	40,917
Depreciation and depletion expense (1)	85,926	55,252	44,865
Impairment of oil and gas properties	2,586	8,517	4,785
	108,036	96,376	104,712
Income tax expense	42,134	38,165	41,466
Results of operations	$ 65,902	$ 58,211	$ 63,246

(1) Depreciation expense of $1.0 million in 2007, $1.0 million in 2006 and $0.9 million in 2005 relating to a transmission pipeline and compression in the Appalachian Basin placed into service from 2004 to 2006 were excluded from depreciation and depletion expense.

In accordance with SFAS No. 143, the combined depletion and accretion expense related to asset retirement obligations that were recognized during 2007, 2006 and 2005 in depreciation, depletion and amortization expense was approximately $0.7 million, $0.2 million and $0.2 million.

Oil and Gas Reserves

The following table sets forth the net quantities of proved reserves and proved developed reserves during the periods indicated. This information includes our royalty and net working interest share of the reserves in oil and gas properties. Net proved oil and gas reserves for the three years ended December 31, 2007 were estimated by Wright and Company, Inc. All reserves are located in the United States. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved oil and gas reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed oil and gas reserves are those reserves expected to be recovered through existing wells with equipment and operating methods.

Proved Development and Undeveloped Reserves	Natural Gas (MMcf)	Oil and Condensate (Mbbl)	Total Equivalents (MMcfe)
December 31, 2004	316,052	6,343	354,110
Revisions of previous estimates	(13,859)	(35)	(14,071)
Extensions, discoveries and other additions	87,860	554	91,184
Production	(25,676)	(306)	(27,515)
Purchases of reserves	—	—	—
Sales of reserves in place	(5,196)	(3,659)	(27,148)
December 31, 2005	359,181	2,897	376,560
Revisions of previous estimates	(10,182)	396	(7,807)
Extensions, discoveries and other additions	97,286	597	100,867
Production	(28,967)	(382)	(31,260)
Purchases of reserves	39,928	1,402	48,346
Sales of reserves in place	—	—	—
December 31, 2006	457,246	4,910	486,706
Revisions of previous estimates (1)	(19,554)	3,853	3,566
Extensions, discoveries and other additions	137,634	6,547	176,915
Production	(37,802)	(461)	(40,569)
Purchases of reserves	72,102	390	74,440
Sales of reserves in place	(21,363)	(19)	(21,476)
December 31, 2007	588,263	15,220	679,582
Proved Developed Reserves:			
December 31, 2005	266,970	2,017	279,070
December 31, 2006	326,480	3,049	344,775
December 31, 2007	372,626	4,463	399,404

(1) Includes reclassification of a portion of the proved undeveloped natural gas reserves to oil and condensate reserves as a result of the future processing of natural gas in East Texas to extract natural gas liquids.

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and gas reserves. Future cash inflows were computed by applying year-end prices of oil and gas to the estimated future production of proved oil and gas reserves. Natural gas prices were escalated only where existing contracts contained fixed and determinable escalation clauses. Contractually provided natural gas prices in excess of estimated market clearing prices were used in computing the future cash inflows only if we expect to continue to receive higher prices under legally enforceable contract terms. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved oil and gas reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available net operating loss carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Future cash inflows	$5,140,818	$2,848,046	$3,902,546
Future production costs	(1,496,057)	(775,561)	(637,907)
Future development costs	(667,118)	(321,338)	(192,938)
Future net cash flows before income tax	2,977,643	1,751,147	3,071,701
Future income tax expense	(727,561)	(435,299)	(834,774)
Future net cash flows	2,250,082	1,315,848	2,236,927
10% annual discount for estimated timing of cash flows	(1,278,172)	(711,248)	(1,200,481)
Standardized measure of discounted future net cash flows	$971,910	$604,600	$1,036,446

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Sales of oil and gas, net of production costs	$(227,136)	$(196,284)	$(236,809)
Net changes in prices and production costs	277,245	(720,914)	516,662
Extensions, discoveries and other additions	241,497	142,007	327,287
Development costs incurred during the year	108,584	50,629	25,725
Revisions of previous quantity estimates	17,846	(24,460)	(54,479)
Purchases of minerals-in-place	69,179	51,810	—
Sales of minerals-in-place	(42,395)	—	(59,864)
Accretion of discount	78,744	141,165	79,459
Net change in income taxes	(106,398)	192,370	(170,261)
Other changes	(49,856)	(68,169)	19,073
Net increase (decrease)	367,310	(431,846)	446,793
Beginning of year	604,600	1,036,446	589,653
End of year	971,910	$604,600	$1,036,446

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

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

None.

Item 9A *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 December 31, 2007. 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 December 31, 2007, such disclosure controls and procedures were effective.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. This evaluation was completed based on the framework established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our management has concluded that, as of December 31, 2007, our internal control over financial reporting was effective. KPMG LLP, an independent registered public accounting firm, has issued an attestation report on our internal control over financial reporting as of December 31, 2007, which is included in Item 8 of this Annual Report or Form 10-K.

(c) Changes in Internal Control Over Financial Reporting

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

Item 9B *Other Information*

There was no information that was required to be disclosed by us on a Current Report on Form 8-K during the fourth quarter of 2007 which we did not disclose.

Part III

Item 10 *Directors, Executive Officers and Corporate Governance*

Except for information concerning our executive officers included Item 1 hereof, in accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11 *Executive Compensation*

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 12 *Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters*

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 13 *Certain Relationships and Related Transactions, and Director Independence*

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14 *Principal Accounting Fees and Services*

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Part IV

Item 15 ***Exhibits, Financial Statement Schedules***

The following documents are filed as exhibits to this Annual Report on Form 10-K:

(1) Financial Statements—The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 76 of this Annual Report on Form 10-K.

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

(3) Exhibits

(3.1) Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(3.2) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(3.3) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).

(3.4) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on June 12, 2007).

(3.5) Amended and Restated Bylaws of Registrant (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on October 26, 2007).

(4.1) Subordinated Indenture dated as of December 5, 2007 among Penn Virginia Corporation, as Issuer, Penn Virginia Holding Corp., Penn Virginia Oil & Gas Corporation, Penn Virginia Oil & Gas GP LLC, Penn Virginia Oil & Gas LP LLC, Penn Virginia MC Corporation, Penn Virginia MC Energy L.L.C., Penn Virginia MC Operating Company L.L.C. and Penn Virginia Oil & Gas, L.P., as Subsidiary Guarantors, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(4.2) First Supplemental Indenture dated December 5, 2007 between Penn Virginia Corporation, as Issuer, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

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

(10.2) First Amendment to Amended and Restated Credit Agreement dated as of December 29, 2004 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2005).

(10.3) Second Amendment to Amended and Restated Credit Agreement dated as of December 15, 2005 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.3 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2005).

(10.4) 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. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006).

(10.5) Fourth Amendment to Amended and Restated Credit Agreement dated as of August 25, 2006 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006).

(10.6) Fifth Amendment to Amended and Restated Credit Agreement dated as of November 1, 2006 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006).

(10.7) Sixth Amendment to Amended and Restated Credit Agreement dated as of April 13, 2007 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on April 16, 2007).

(10.8) Seventh Amendment to Amended and Restated Credit Agreement dated as of June 12, 2007 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 18, 2007).

(10.9) Waiver and Eighth Amendment to Amended and Restated Credit Agreement dated as of August 1, 2007 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on August 2, 2007).

(10.10) Waiver and Ninth Amendment to Amended and Restated Credit Agreement dated as of October 5, 2007 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 9, 2007).

(10.11) Waiver and Tenth Amendment to Amended and Restated Credit Agreement dated as of November 26, 2007 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on November 27, 2007).

(10.12) Call Option Confirmation dated November 29, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.13) Call Option Confirmation dated November 29, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.14) Call Option Confirmation dated November 29, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation. (incorporated by reference to Exhibit 10.5 to Registrant's Current Report on Form 8-K filed on December 5, 2007)

(10.15) Call Option Confirmation dated November 29, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.7 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.16) Warrant Confirmation dated November 29, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.17) Warrant Transaction Amendment dated December 3, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.9 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.18) Warrant Confirmation dated November 29, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.19) Warrant Transaction Amendment dated December 3, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.11 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.20) Warrant Confirmation dated November 29, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.21) Warrant Transaction Amendment dated December 3, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation (incorporated by reference to Exhibit 10.10 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.22) Warrant Confirmation dated November 29, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.8 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.23) Warrant Transaction Amendment dated December 3, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.12 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

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

(10.25) Amendment No. 1 to Omnibus Agreement dated December 19, 2002 among the Penn Virginia Corporation, Penn Virginia Resource GP, LLC, Penn Virginia Operating Co., LLC and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 10.9 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

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

(10.27) Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*

(10.28) Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*

(10.29) Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan.

(10.30) Form of Agreement for Deferred Common Stock Unit Grants under the Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan.*

(10.31) Penn Virginia Corporation Fourth Amended and Restated 1999 Employee Stock Incentive Plan.

(10.32) Form of Agreement for Stock Option Grants under the Penn Virginia Corporation Fourth Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*

(10.33) Form of Agreement for Restricted Stock Awards under the Penn Virginia Corporation Fourth Amended and Restated 1999 Employee Stock Incentive Plan.*

(10.34) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and A. James Dearlove (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 2, 2006).*

(10.35) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and Frank A. Pici (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on March 2, 2006).*

(10.36) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on March 2, 2006).*

(10.37) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 10-Q filed on March 2, 2006).*

(10.38) Executive Change of Control Severance Agreement dated March 9, 2006 between Penn Virginia Resource GP, LLC and Keith D. Horton (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 14, 2006).*

(10.39) Executive Change of Control Severance Agreement dated March 9, 2006 between Penn Virginia Resource GP, LLC and Ronald K. Page (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on March 14, 2006).*

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

(21.1) Subsidiaries of Penn Virginia Corporation.

(23.1) Consent of KPMG LLP.

(23.2) Consent of Wright & Company, Inc.

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

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

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

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

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* Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENN VIRGINIA CORPORATION

February 29, 2008

By: /s/ FRANK A. PICI
Frank A. Pici
Executive Vice President and Chief Financial Officer

February 29, 2008

By: /s/ FORREST W. MCNAIR
Forrest W. McNair
Vice President and Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ ROBERT GARRETT **Robert Garrett**	Chairman of the Board and Director	February 29, 2008
/s/ EDWARD B. CLOUES, II **Edward B. Cloues, II**	Director	February 29, 2008
/s/ A. JAMES DEARLOVE **A. James Dearlove**	Director and President and Chief Executive Officer	February 29, 2008
/s/ KEITH D. HORTON **Keith D. Horton**	Director and Executive Vice President	February 29, 2008
/s/ STEVEN W. KRABLIN **Steven W. Krablin**	Director	February 29, 2008
/s/ MARSHA R. PERELMAN **Marsha R. Perelman**	Director	February 29, 2008
/s/ WILLIAM H. SHEA, JR. **William H. Shea**	Director	February 29, 2008
/s/ PHILIPPE VAN MARCKE DE LUMMEN **Philippe van Marcke de Lummen**	Director	February 29, 2008
/s/ GARY K. WRIGHT **Gary K. Wright**	Director	February 29, 2008

Exhibit 31.1

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

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

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2008

/s/ A. JAMES DEARLOVE

A. James Dearlove
President and Chief Executive Officer

Exhibit 31.2

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

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

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2008

/s/ FRANK A. PICI

Frank A. Pici
Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, A. James Dearlove, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: February 28, 2008

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

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

Exhibit 32.2

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

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Pici, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: February 28, 2008

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

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

Photo left to right

Corporate Information

DIRECTORS

Robert Garrett

Edward B. Cloues, II

A James Dearlove

Keith D. Horton

Steven W Krablin

Marsha Reines Perelman

William H. Shea, Jr.

Philippe van Marcke de Lummen

Gary K. Wright

MANAGEMENT

A James Dearlove

Frank A. Pici

H. Baird Whitehead

Keith D. Horton

Nancy M. Snyder

Ronald K. Page

Forrest W. McNair

Dana G Wright

Steven A. Hartman

James D. McKinney

Michael W. Mooney

Patrick J Udovich

James F Modzelewski

ANNUAL MEETING

Penn Virginia Corporation's Annual Meeting will be held 10 a.m. May 7, 2008

TRANSFER AGENT AND REGISTRAR

American Stock Transfer and Trust Company

CERTIFICATIONS

125th ANNIVERSARY

1882-2007

PENN VIRGINIA CORPORATION
Three Radnor Corporate Center, Suite 300
100 Matsonford Road, Radnor, PA 19087
610.687.8900 phone 610.687.3688 fax
www.pennvirginia.com

This is a
green™
ANNUAL REPORT
www.GreenAnnualReport.com

Penn Virginia Corporation saved the following resources by producing this Green Annual Report™

7.59 trees preserved for the future	**19.04** lbs water-borne waste not created	**2801** gals wastewater flow saved
310 lbs solid waste not generated	**610** lbs net greenhouse gases prevented	**4,670,750** million BTUs energy not consumed

END