08044817

PENN VIRGINIA RESOURCE PARTNERS, L.P.

2007 Annual Report

Headquartered in Radnor, PA, Penn Virginia Resource Partners, L.P. (NYSE: PVR) is a publicly traded limited partnership (PTP) formed by Penn Virginia Corporation (NYSE: PVA). PVR manages coal and natural resource properties and related assets and operates a midstream natural gas gathering and processing business. For more information, please visit PVR's website at www.pvresource.com.

Financial Highlights

In millions except per share data	2007	2006	2005	2004	2003
FINANCIAL DATA					
Net revenues[1]	$ 206.2	$ 183.3	$ 142.4	$ 75.6	$ 55.6
Operating income	117.7	102.8	78.1	40.5	26.6
Net income	56.6	73.9	51.2	34.3	22.7
Cash flow from operations	127.8	107.3	93.7	54.8	41.1
Distributable cash flow[2]	120.8	100.2	85.5	52.8	39.3
Total assets	931.3	714.0	657.9	284.4	259.9
Long-term debt, excluding current portion	399.2	207.2	246.8	112.9	90.3
Partners' capital	371.3	402.2	284.0	150.0	153.8
Long-term debt as percent of total capitalization	52%	34%	46%	43%	37%
PER LIMITED PARTNER UNIT DATA[3]					
Net income[4]	$ 0.96	$ 1.56	$ 1.22	$ 0.93	$ 0.62
Cash distributions declared[5]	1.72	1.60	1.30	1.08	1.04
Weighted average number of limited partner units outstanding	46.1	42.0	40.3	36.1	35.9
OPERATING DATA					
Coal produced by lessees (millions of tons)	32.5	32.8	30.2	31.2	26.5
Coal royalties ($/ton)	$ 2.89	$ 2.99	$ 2.74	$ 2.23	$ 1.90
Estimated coal reserves (millions of recoverable tons)	818	765	689	558	588
Natural gas system volumes	186	170	144	—	—

[1] 2007, 2006 and 2005 amounts are shown net of cost of gas purchased of $343 million, $335 million and $304 million, respectively.

[2] Distributable cash flow is calculated as follows:

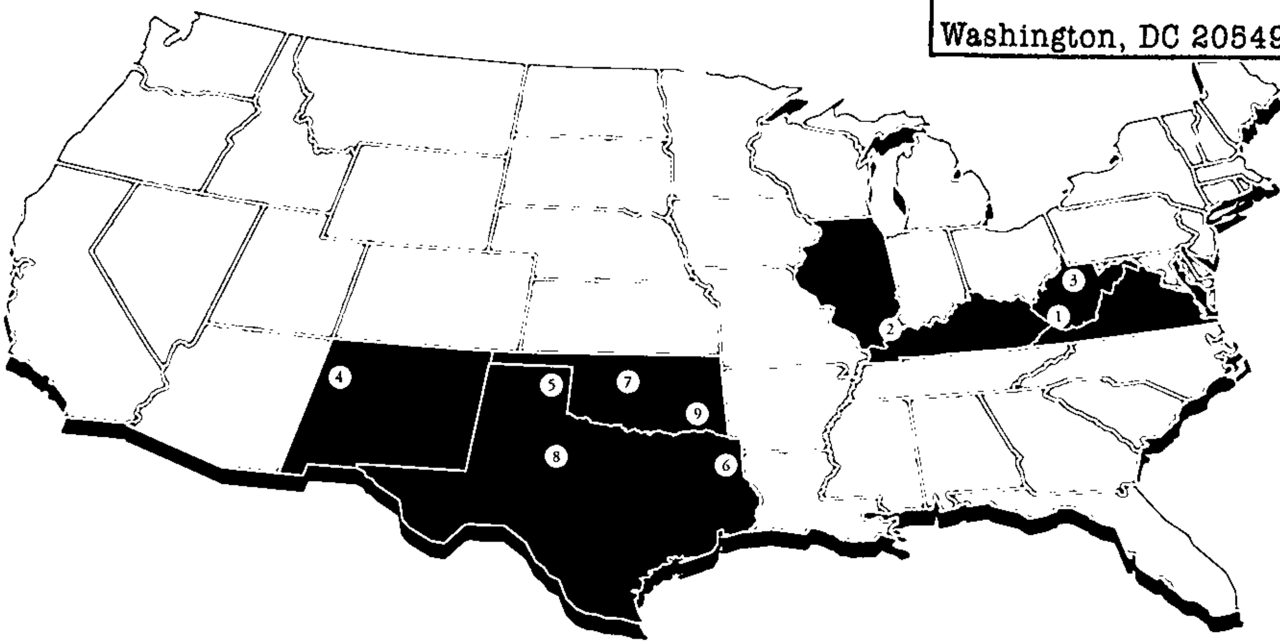
	2007	2006	2005	2004	2003
Operating income	$ 117.7	$ 102.8	$ 78.1	$ 40.5	$ 26.6
Depreciation, depletion and amortization	41.5	37.5	30.6	18.6	16.6
Derivative losses (gains) included in operations	4.6	1.9	(1.0)	—	—
Cash paid for derivative settlements	(17.8)	(19.4)	(4.7)	—	—
Interest expense, net	(15.5)	(17.6)	(12.9)	(6.2)	(3.8)
Maintenance capital expenditures	(9.8)	(9.5)	(4.6)	(0.1)	(0.1)
Other	—	4.5	—	—	—
Distributable cash flow	$ 120.8	$ 100.2	$ 85.5	$ 52.8	$ 39.3

[3] Per unit data reflects 2-for-1 unit split in April 2006.

[4] Per unit amount is computed after general partner's share.

[5] Annualized as of last distribution paid in year.

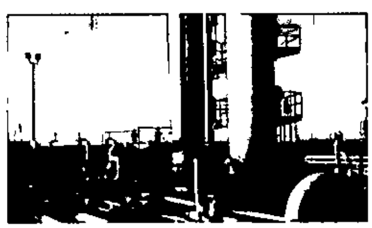
PVR's Coal and Natural Resource M



1. Central Appalachia - Coal reserves and infrastructure, timber, oil and gas royalties
2. Illinois Basin - Coal reserves and infrastructure
3. Northern Appalachia - Coal reserves
4. San Juan Basin - Coal reserves
5. Beaver / Spearman - Gas processing plants and gathering systems
6. Crossroads - Gas processing plant and pipelines
7. Crescent - Gas processing plant and gathering system
8. Hamlin - Gas processing plant and gathering system
9. Arkoma - Gas gathering systems

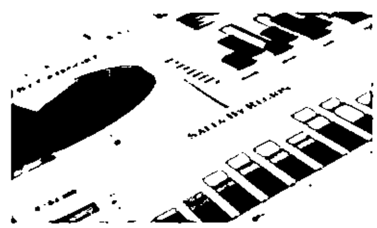
COAL AND NATURAL RESOURCE MANAGEMENT

PVR Coal and Natural Resource Management manages coal and natural resource properties, provides fee-based coal preparation and loading services, sells timber, collects oil and gas royalties, and collects wheelage fees from the transportation of coal. PVR continues to add coal reserves in multiple basins, expand its coal services and infrastructure business as well as to acquire other PTP-friendly natural resource assets, such as timber and natural gas royalties.



NATURAL GAS MIDSTREAM

PVR Midstream provides gas processing, gathering and other related natural gas services at four primary locations in Texas and Oklahoma, with a fifth system to be on line by the second quarter of 2008 in east Texas. PVR continues to identify and acquire additional gathering, processing and related assets, expand existing systems via new-well connections and processing plants, and develop ways to increase its service level to Penn Virginia Corporation's oil and gas exploration and production business.



FINANCIAL DISCIPLINE

PVR continues to increase distributions at a rate competitive with other PTPs, after reviewing the reinvestment needed to sustain long-term growth. PVR has historically funded its growth through a combination of debt and new unit issuances. PVR seeks growth opportunities that provide increases in sustainable distributable cash flow at attractive rates of return for unitholders, together with stable cash flows and the potential for additional organic growth.

Dear Fellow Unitholders

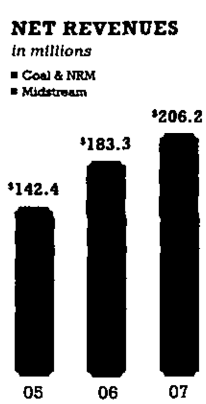
Penn Virginia Resource Partners, L.P. (PVR) had another record year in 2007, setting new highs for revenues, operating income and distributable cash flow. We also enjoyed record-setting natural gas midstream system throughput volumes and gross processing margins, while coal production by our lessees was essentially flat from record 2006 levels. We increased distributions to unitholders three times during 2007, with total distributions up eight percent over 2006.

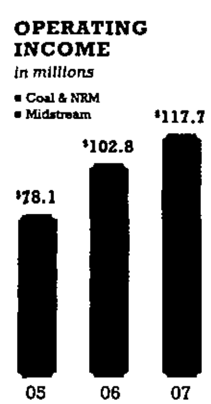
In our Coal and Natural Resource Management (NRM) segment, coal reserves increased to 818 million tons as of year-end 2007 from 765 million tons at year-end 2006. We replaced 263 percent of the 32.5 million tons of reserves produced by lessees during 2007, primarily through two acquisitions of approximately 60 million tons in the Illinois Basin. As a result of recent acquisitions, approximately 21 percent of our reserve base is in the Illinois Basin. Our belief is this basin's proximity to power plants and expected future regulations requiring scrubbing of most coals will increase the competitiveness of the Illinois Basin coals. Approximately 70 percent of our reserve base is high quality coal reserves in Central Appalachia and we continue to pursue acquisitions in this region.

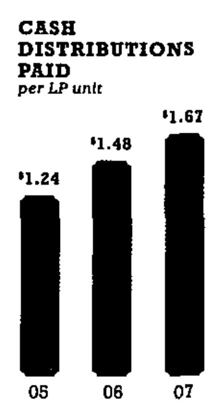
Coal prices increased throughout 2007, especially during the fourth quarter, as increased foreign demand, overseas supply issues and a weaker U.S. dollar fueled growth in exports. Domestic demand was also strong during 2007, as power consumption grew and the costs of competing fuels remained high. Natural gas prices stayed high relative to coal during the year, despite high gas storage inventories, largely as the result of record oil prices and increased demand. As a result, coal remains the fuel of choice for domestic electricity generation.

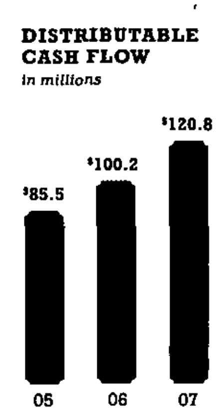
During the second half of 2007, we completed approximately $124 million in acquisitions of Appalachian forestland ($93 million) and oil and gas royalties ($31 million). These acquisitions significantly expanded existing business lines and provided a larger, more diversified cash flow stream within the segment. We have experience managing these natural resource business lines and believe that these types of assets are extremely "friendly" to publicly traded partnerships (PTPs) given their very long-lived, low-risk cash flow streams and the absence of a need for maintenance capital.

PVR Midstream was the primary contributor to our record setting financial performance in 2007. System throughput volumes increased nine percent and the gross processing margin increased 32 percent. The growth in system throughput volumes was attributable to "organic" growth in natural gas production from existing fields we service, and the processing margin increase also benefited largely from record fractionation or "frac" spreads during much of 2007. By April 2008, we expect to bring on line two new processing plants on line. One is in the panhandle of Texas at the Beaver / Spearman complex, our largest natural gas gathering and processing system. The new plant will have a processing capacity of 60 million cubic feet of natural gas per day (MMcfd), will allow us to earn processing margins on gas we previously had to bypass and will provide the ability to process third party volumes in an extended operating area. The other plant, which we refer to as the "Crossroads" plant in east Texas, will have a processing capacity of 80









2007 growth in operating income	2007 growth in distributable cash flow	2007 growth in cash flow from operations
14%	21%	19%

MMcfd and will process a portion of the Cotton Valley gas production of Penn Virginia Corporation (NYSE: PVA) and that of other area producers. The Crossroads plant is expected to be a "win-win" for the Penn Virginia family of companies, in that PVR Midstream will generate fee-based cash flow from Crossroads while PVA's oil and gas business will receive a benefit from the sale of natural gas liquids processed by the plant, which it previously did not receive.

PVR Midstream is expected to continue to be a growth platform for us, both organically, by tying new natural gas production to existing systems and expanding existing or constructing new facilities, and from acquisitions in the natural gas midstream sector. We will also continue to explore ways to provide additional facilities and services to PVA's oil and gas business.

As we enter 2008, we look forward to additional cash flow contributions from our new midstream processing capacity. We also look forward to full-year contributions to our coal and natural resource management segment from our recent acquisitions of coal reserves, timber and oil and gas royalties. In both segments, we will continue the pursuit of organic and acquisition opportunities.

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

James Dearlove

A. James Dearlove
Chairman, President and
Chief Executive Officer

2007 EXPANSION

Our management continues to focus on acquisitions that increase and diversify our sources of long-term cash flow. During 2007, we acquired 60 million tons of coal reserves via two transactions in the Illinois Basin for an aggregate purchase price of approximately $52 million. In addition, we acquired approximately 62,000 acres of forestland in West Virginia for a purchase price of approximately $93 million. We also acquired royalty interests in certain oil and gas leases in Kentucky and Virginia from Penn Virginia Corporation for a purchase price of approximately $31 million. All four of these acquisitions significantly expanded PVR Coal and Natural Resource Management and further diversified the cash flows from that segment. At PVR Midstream, we spent $39 million on expansion projects related to the construction of two natural gas processing facilities in the panhandle of Texas and in east Texas, which are expected to commence operations by April 2008.

Coal and Natural Resource Management

At year-end 2007, we owned or controlled a record 818 million tons of proven and probable coal reserves, an increase of seven percent from the prior year level. In 2007, coal production by our lessees was 32.5 million tons, relatively flat from a record 32.8 million tons in 2006. Segment operating income was $68.8 million in 2007, six percent lower than 2006's record $73.4 million.

Keith D. Horton
PVA Director,
Executive Vice President
PVR Co-President
and COO – Coal

Our coal reserves are located in Central Appalachia, the Illinois Basin, Northern Appalachia and the San Juan Basin. During 2007, reserve increases in the Illinois Basin and Central Appalachia were partially offset by decreases in Northern Appalachia and the San Juan Basin. Production decreases in Central Appalachia and Northern Appalachia were largely offset by production increases in the Illinois and San Juan Basins.

During 2007, revenues for PVR Coal and NRM decreased one percent to $111.6 million from $113.0 million in 2006 primarily due to a four percent decrease in coal royalties revenue, partially offset by an 18 percent increase in coal services and natural resource management revenues. Coal royalties revenue decreased slightly during 2007 primarily due to a decrease in average coal royalties per ton. The decrease was largely due to the combination of increased production in the Illinois Basin, which has lower coal prices and therefore lower royalty realizations, and reduced production in Central Appalachia. Average coal royalties per ton decreased three percent to $2.89 in 2007 from $2.99 in the prior year.

COAL ROYALTIES REVENUE
in millions

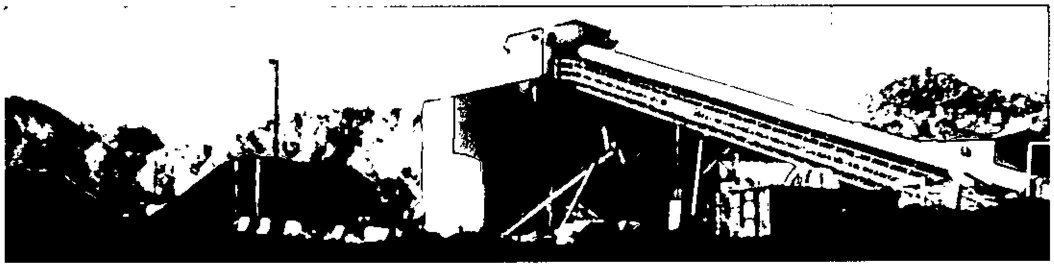
COAL ROYALTIES
per ton

We 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. The 2007 acquisitions in the Illinois Basin complement the approximate 116 million tons of western Kentucky coal we purchased in 2005 and 2006. We believe that production from the Illinois Basin will grow because of its proximity to power plants and also because of expected future environmental regulations which will require increased scrubbing of most coals, including lower sulfur coals from other basins. We expect to continue to diversify our coal reserve holdings into this and other domestic basins in the future.

In the second half of 2007, we completed acquisitions of forestland and oil and gas royalties in Appalachia for approximately $124 million. We plan to expand our coal services and infrastructure business, which had revenue growth of 24 percent in 2007, as well as to continue to expand our natural resource management businesses in the future; however, the main focus of the segment will remain on acquiring coal reserves.

The September 2007 acquisition of approximately 62,000 acres of forestland in West Virginia for a purchase price of approximately $93 million significantly expanded our existing timber management business. As a result of the acquisition, we owned approximately 220,000 acres of forestland in Kentucky, Virginia and West Virginia at year-end 2007. The $31 million acquisition of oil and gas royalties in eastern Kentucky and southwestern Virginia from PVA expanded our exposure to this sub-segment.

We also look to continue to expand our coal services and infrastructure business. Coal infrastructure projects typically involve long-lived, fee-based assets that generally produce steady and predictable cash flows and are therefore attractive to PTPs. We own a number of such infrastructure facilities and intend to continue to look for growth opportunities in this area of operations. During 2007, we acquired a preparation plant in



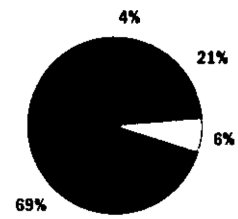
Coal loading facility
in Central Appalachia

connection with our acquisition of coal reserves in western Kentucky. We also have an equity interest in a coal handling joint venture, which is seeking to develop opportunities for coal related infrastructure projects involving end users.

In 2007, approximately 81 percent of the coal produced from our properties was subject to leases which required our 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 our lessees under long-term contracts, typically one to three years in length. The royalties we received on the other 19 percent of coal produced from our properties were based on fixed rates per ton, which escalate annually.

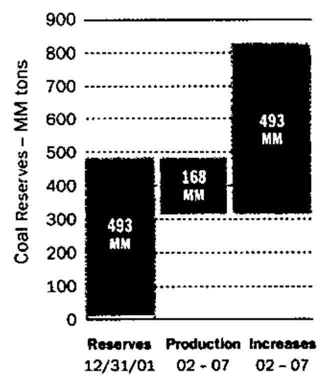
In the second half of 2006 and continuing into 2007, coal prices decreased from the historically high levels experienced in the previous two and one half years, due to higher than normal coal inventories at electric utilities and milder than normal winter weather. Coal prices increased significantly in the fourth quarter of 2007. The global markets for most types of coal remain strong. Continued demand from emerging countries and increased domestic consumption 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 is strong in early 2008 primarily due to increasing global demand and supply difficulties. We believe the increase in coal prices will benefit our lessees during 2008 as many of them will enter into new long-term supply contracts.

YEAR-END 2007 COAL RESERVES
MM tons

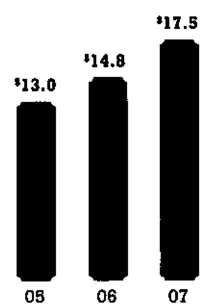


Central Appalachia	569
N. Appalachia	30
Illinois Basin	169
San Juan Basin	51
Total	819

COAL RESERVES



OTHER NATURAL RESOURCE MANAGEMENT REVENUES
in millions



Natural Gas Midstream

PVR Midstream derives revenues primarily from gas purchase and 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.

Ronald K. Page
PVA Vice President
PVR Co-President
and COO – Midstream

We own and operate natural gas midstream assets that include approximately 3,700 miles of natural gas gathering pipelines and three natural gas processing plants, which had 160 MMcfd of total capacity at year-end 2007. Segment operating income was a record $48.9 million in 2007, 67 percent higher than $29.4 million in 2006, due primarily to higher processing margins in 2007.

Our natural gas midstream operations currently include the Beaver / Spearman gathering and processing facilities in the panhandles of Texas and Oklahoma, the Crescent gathering and processing facilities in central Oklahoma, the Hamlin gathering and processing facilities in west-central Texas and the Arkoma gathering system in eastern Oklahoma. There are approximately 2,200 producing wells connected to our natural gas gathering pipelines, with the Beaver / Spearman and Crescent systems comprising the majority of the well-connects and processing capacity

The 67 percent increase in operating income was primarily the result of high frac spreads during 2007 caused by higher NGL sale prices and lower natural gas purchase costs, along with an increase in system throughput volumes. The gross processing margin increased by 32 percent to $89.9 million, or $1.33 per Mcf, in 2007, from $68.1 million, or $1.10 per Mcf, in the prior year. Adjusted for the cash impact of derivatives, the gross processing margin was $76.7 million, or $1.13 per Mcf, in 2007, up 51 percent from $50.6 million, or $0.82 per Mcf, in the prior year.

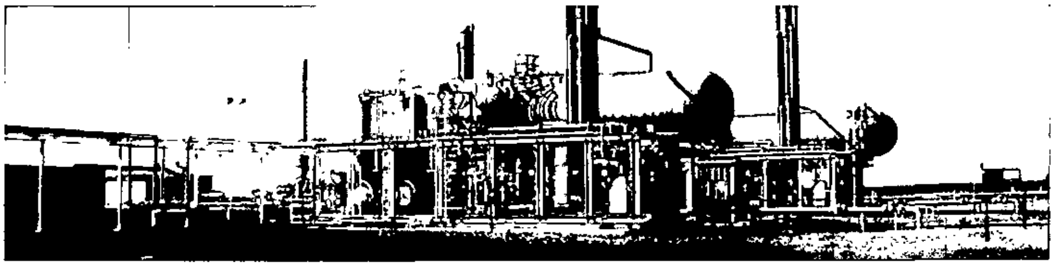
System throughput volumes at our gas processing plants and gathering systems increased nine percent to 67.8 Bcf, or approximately 186 MMcf per day, in 2007 from 62.0 Bcf, or approximately 170 MMcf per day, in the prior year. The increase in system throughput volumes was primarily due to our success in 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 our systems.

We commenced our natural gas midstream operations through an acquisition in March 2005 and have continued to grow this segment through additional acquisitions and expansion projects. We also continue to explore potential operating synergies with PVA's oil and gas exploration and production business, including marketing natural gas production and building a processing plant in east Texas.

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

During 2007, we spent $38.7 million on expansion projects to allow us to capitalize on such opportunities. The expansion projects included two natural gas processing facilities with a combined 140 MMcfd of inlet gas capacity, which are expected to commence operations by April 2008. These two natural gas processing plants include the Crossroads plant in east Texas, with 80 MMcfd capacity, which will process most of the liquids-rich Cotton Valley gas production for PVA, and the Spearman plant, with 60 MMcfd capacity, which will process gas that currently is bypassing our largest plant (Beaver), which is at capacity.

During 2007, PVR Midstream generated a majority of its gross margin from gas purchase / keep-whole (37 percent) and percentage-of-proceeds (34 percent) contractual arrangements, under which our gross margin is exposed to increases and decreases in the price of natural gas and natural gas liquids (NGLs).



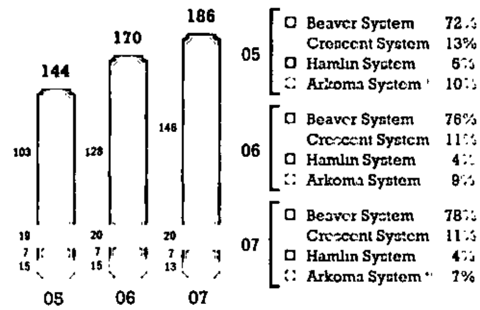
100 MMcfd processing plant at Beaver in the panhandle of Texas, PVR's largest facility

The remaining 29 percent of the gross margin was generated by system throughput volumes processed under fee-based gathering contracts. As a result, much of PVR Midstream's profitability depends on the relationship between the price we receive for the NGLs we extract and sell at our processing plants and the price of natural gas we purchase from producers. The difference between these two prices, the fractionation or "frac" spread, can be volatile and difficult to predict. Therefore, we employ various commodity price derivatives to protect our margins.

ORGANIC GROWTH

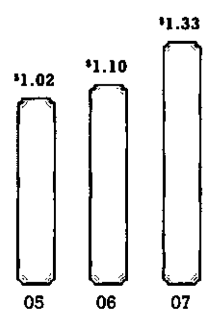
Due to high commodity prices and increased competition to purchase energy assets, acquisition costs have risen and corresponding acquisition rates of return have fallen over the past few years. In response, we and other PTPs have sought supplemental growth via "organic" or non-acquisition opportunities. Examples of this type of organic growth in midstream include successfully competing for increased well-connects in producing areas with strong production growth, engaging in drop-down transactions involving assets sold by a parent or other affiliated entity, and constructing, rather than buying, new midstream assets. We have successfully engaged in these types of activities over the past two years in both the midstream segment (e.g., increased well-connects, construction of new processing plants) and the coal and natural resource management segment (e.g., coal infrastructure, oil and gas royalties). The goals of such organic growth efforts are to reduce the costs of overall growth and to thereby improve returns to unitholders relative to an acquire-only growth model.

SYSTEM THROUGHPUT VOLUMES
MMcf per day

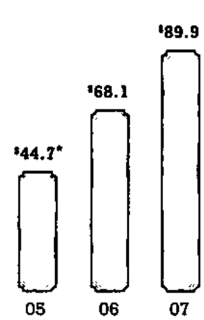


(a) Gathering volumes only

MIDSTREAM PROCESSING MARGIN
per Mcf of system throughput volume



MIDSTREAM PROCESSING MARGIN
in millions



* *10 month data for 2005*

2007 Acquisition and Expansion Summary

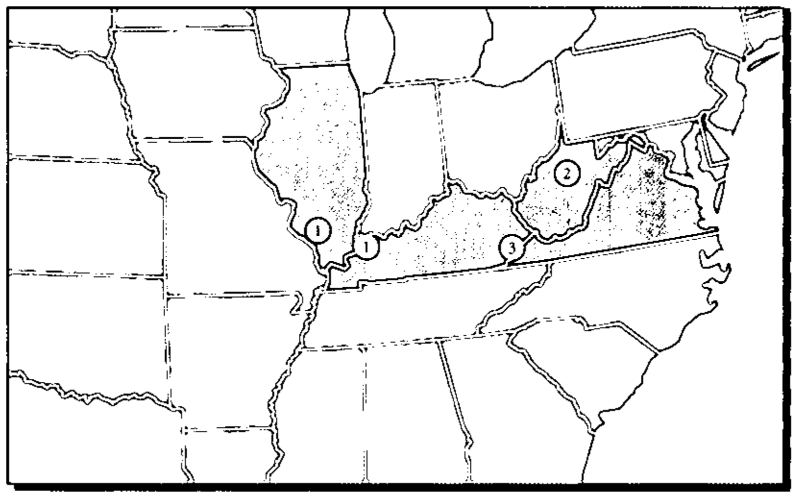
We seek growth via acquisitions and also through organic growth expansion opportunities. During 2007, we completed two coal reserve acquisitions in the Illinois Basin, as well as the acquisition of forestland in West Virginia and oil and gas royalty interests in properties in Virginia and Kentucky. Furthermore, we began the construction of two processing plants in Texas in 2007, which will both be on line by April 2008 and will significantly expand our processing capacity at a time when gross processing margins are at or near record levels.

Coal and Natural Resource Management Transactions

(1) Illinois Basin Coal Reserve Acquisitions
$52 Million / 60 MM tons

(2) West Virginia Forestland Acquisition
$93 Million / 62,000 acres

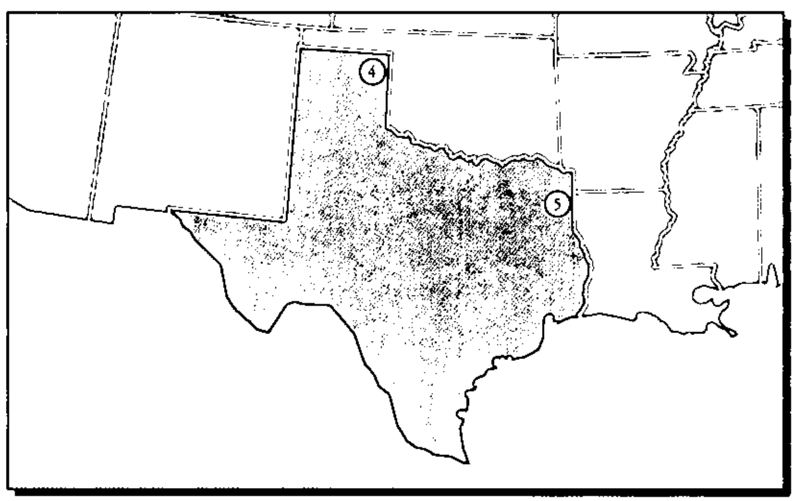
(3) Kentucky & Virginia Royalty Acquisition
$31 Million / 8.7 Bcfe



Natural Gas Midstream Expansion

(4) Spearman Gas Processing Plant
60 MMcfd capacity

(5) Crossroads Gas Processing Plant
80 MMcfd capacity



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: 1-16735

Penn Virginia Resource Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**23-3087517**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

SEC Mail Processing Section

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

APR - 2 2008

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

Washington, DC 100

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

Title of each class	Name of exchange on which registered
Common Units	**New York Stock Exchange**

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

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 units held by non-affiliates of the registrant was $809,323,853 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 units as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including the registrant's general partner, all affiliates of the registrant's general partner and all directors and executive officers of the registrant's general partner. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 28, 2008, 46,106,285 common units representing limited partner interests of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

Table of Contents

Part I

Item 1 *Business*

General

Penn Virginia Resource Partners, L.P. (NYSE: PVR) is a publicly traded Delaware limited partnership formed by Penn Virginia Corporation (NYSE: PVA), or 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. Both in our current limited partnership form and in our previous corporate form, we have managed coal properties since 1882. We currently conduct operations in two business segments: (1) coal and natural resource management and (2) natural gas midstream. Our operating income was $117.7 million in 2007, compared to $102.8 million in 2006 and $78.1 million in 2005. In 2007, our coal and natural resource management segment contributed $68.8 million, or 58%, to operating income, and our natural gas midstream segment contributed $48.9 million, or 42%, to operating income. Unless the context requires otherwise, references to the "Partnership," "we," "us" or "our" in this Annual Report on Form 10-K refer Penn Virginia Resource Partners, L.P. and its subsidiaries.

Coal and Natural Resource Management Segment Overview

Our coal and natural resource management segment primarily involves the management and leasing of coal and natural resource properties and the subsequent collection of royalties. We also earn revenues from the provision of fee-based coal preparation and loading services, from the sale of standing timber on our properties, from oil and gas royalty interests we own and from coal transportation, or wheelage, fees.

As of December 31, 2007, we 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 our 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. We enter into long-term leases with experienced, third-party mine operators, providing them the right to mine our coal reserves in exchange for royalty payments. We actively work with our lessees to develop efficient methods to exploit our reserves and to maximize production from our properties. We do not operate any mines. In 2007, our lessees produced 32.5 million tons of coal from our properties and paid us coal royalties revenues of $94.1 million, for an average royalty per ton of $2.89. Approximately 81% of our coal royalties revenues in 2007 and 84% of our coal royalties revenues in 2006 were derived from coal mined on our 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 our coal royalties revenues for the respective periods was derived from coal mined on our properties under leases containing fixed royalty rates that escalate annually. See "—Contracts—Coal and Natural Resource Management Segment" for a description of our coal leases.

Natural Gas Midstream Segment Overview

Our natural gas midstream segment is engaged in providing gas processing, gathering and other related natural gas services. We own and operate 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. Our natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. We also own 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. We acquired our first natural gas midstream assets through the acquisition of Cantera Gas Resources, LLC, or Cantera, in March 2005.

In 2007, system throughput volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 67.8 Bcf, or approximately 186 MMcfd. In 2007, three of our natural gas midstream customers, ConocoPhillips Company, Equistar Chemicals, LP and BP Canada Energy Marketing Corp., accounted for 25%, 14% and 14% of our natural gas midstream revenues and 20%, 11% and 11% of our total consolidated revenues.

Business Strategy

Our primary business objective is to create sustainable, capital-efficient growth in distributable cash flow to maximize our cash distributions to our unitholders by expanding our coal property management and natural gas gathering and processing businesses through both internal growth and acquisitions. We have successfully grown our business through organic growth projects and acquisitions of coal and natural resource properties and natural gas midstream assets. Since our initial public offering in October 2001, we have completed numerous accretive acquisitions with an aggregate purchase price of approximately $750 million. For a more detailed discussion of our acquisitions, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments." We intend to continue to pursue the following business strategies:

- *Continue to grow coal reserve holdings through acquisitions and investments in our existing market areas, as well as strategically entering new markets.* During 2007, we increased our coal reserves by 60 million tons, or 8%, from our coal reserves as of December 31, 2006, by completing two acquisitions for an aggregate purchase price of approximately $52 million. While we continue to build upon our core holdings in Appalachia, we also continue to pursue coal opportunities in other areas. For example, in 2005, 2006 and 2007, we made investments in Illinois Basin coal reserves because we view the Illinois Basin as a growth area, both because of its proximity to power plants and because we expect future environmental regulations will require scrubbing of not only higher sulfur Illinois Basin coal, but most coals, including lower sulfur coals from other basins. We expect to continue to diversify our coal reserve holdings into this and other domestic basins in the future.

- *Expand our coal services and infrastructure business on our properties.* Coal infrastructure projects typically involve long-lived, fee-based assets that generally produce steady and predictable cash flows and are therefore attractive to publicly traded limited partnerships. We own a number of such infrastructure facilities and intend to continue to look for growth opportunities in this area of operations. For example, we completed the construction of a new preparation and loading facility in September 2006 on property we acquired in 2005. Operations at the facility commenced in the fourth quarter of 2006. In 2007, we acquired a preparation plant in connection with our acquisition of coal reserves. We also have an equity interest in a coal handling joint venture, which is expected to provide other development opportunities for coal-related infrastructure projects.

- *Expand our other natural resource management assets.* Our management continues to focus on acquisitions that increase and diversify our sources of long-term cash flow. For example, in 2007, we 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.

- *Expand our natural gas midstream operations through acquisitions of new gathering and processing related assets and by adding new production to existing systems.* We continually seek new supplies of natural gas both to offset the natural declines in production from the wells currently connected to our systems and to increase system throughput volumes. New natural gas supplies are obtained for all of our systems by contracting for production from new wells, connecting new wells drilled on dedicated acreage and by contracting for natural gas that has been released from competitors' systems. During 2007, we expended $38.7 million on expansion projects to allow us to capitalize on such opportunities. 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.

- *Utilize the advantages of our relationship with Penn Virginia.* During 2006, we began marketing Penn Virginia's natural gas production in Louisiana, Oklahoma and Texas, allowing us to add a new source of revenues. In 2007, we 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 Penn Virginia. The new east Texas plant will provide fee-based gas processing services to Penn Virginia's oil and gas business, as well as other producers. In addition, as discussed above, we purchased approximately $31 million of oil and gas royalty interests from Penn Virginia. We will continue to look for ways to take advantage of our natural relationship with Penn Virginia in mutually beneficial ways.

Contracts

Coal and Natural Resource Management Segment

We earn most of our coal royalties revenues under long-term leases that generally require our lessees to make royalty payments to us 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 our coal royalties revenues are earned under long-term leases that require the lessees to make royalty payments to us 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 our leases require the lessee to pay minimum rental payments to us 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 us once coal production commences.

Substantially all of our leases impose obligations on the lessees to diligently mine the leased coal using modern mining techniques, indemnify us for any damages we incur in connection with the lessee's mining operations, including any damages we 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 our written consent prior to assigning the lease and maintain commercially reasonable amounts of general liability and other insurance. Substantially all of the leases grant us 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 us the right to terminate the lease and take possession of the leased premises.

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

Natural Gas Midstream Segment

Our 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, our 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 our 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, we generally purchase 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). We then gather the natural gas to one of our plants where it is processed to extract the entrained NGLs, which are then sold to third parties at market prices. We resell 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, we retain a reduced volume of gas to sell after processing. Accordingly, under these arrangements, our revenues and gross margins increase as the price of NGLs increases relative to the price of natural gas, and our revenues and gross margins decrease as the price of natural gas increases relative to the price of NGLs. We have generally been able to mitigate our exposure in the latter case by requiring the payment under many of our gas purchase/keep-whole arrangements of minimum processing charges which ensure that we receive a minimum amount of processing revenues. The gross margins that we realize 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, we generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit 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, our revenues and gross margins increase as natural gas prices and NGL prices increase, and our revenues and gross margins decrease as natural gas prices and NGL prices decrease.

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

In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our 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.

We are 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 us, 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 Penn Virginia. The marketing agreement was effective September 1, 2006. Revenues from this business do not generate qualifying income for a publicly traded limited partnership, but we do not expect it to have an impact on our tax status, as it does not represent a significant percentage of our 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. We utilize 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. We also utilize swap derivative contracts to hedge against the variability in our "frac spread." Our frac spread is the spread between the purchase price for the natural gas we purchase from producers and the sale price for the NGLs that we sell after processing. We hedge against the variability in our 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.

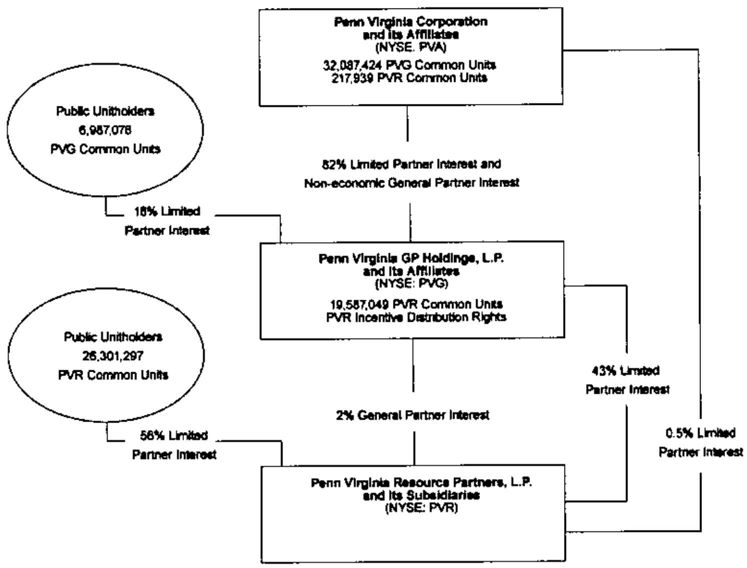
With respect to a costless collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make payment to the counterparty if the settlement price for any settlement period is above 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. 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 7 in the Notes to Consolidated Financial Statements for a further description of our derivatives program.

Partnership Structure

Penn Virginia, a publicly held energy company based in Radnor, Pennsylvania, has been engaged in the coal royalty business since 1882 and is also engaged in the exploration, development and production of natural gas and oil. Penn Virginia formed us in July 2001 to own and operate substantially all of the assets of and assume the liabilities relating to Penn Virginia's coal land management business. We completed our initial public offering in October 2001. Penn Virginia continues to hold a significant interest in us through its indirect controlling interest in Penn Virginia GP Holdings, L.P. (NYSE: PVG), or PVG, a publicly traded Delaware limited partnership.

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through an operating company, Penn Virginia Operating Co., LLC, or the Operating Company. The following diagram depicts our and our affiliates' current simplified organizational and ownership structure as of December 31, 2007:



Relationship with Penn Virginia Corporation

Penn Virginia has a history of successfully completing energy acquisitions. We pursue acquisitions independently and have the opportunity to participate jointly with Penn Virginia in reviewing potential acquisitions. These may include acquisitions of properties containing multiple natural resources, such as oil, natural gas, coal and timber, as well as infrastructure related to those resources, such as natural gas gathering systems and coal preparation plants and loading facilities. We would expect to retain all coal reserves and related infrastructure, all timber resources and all natural gas gathering systems acquired in any such joint acquisition and to allocate the remaining purchased assets between us and Penn Virginia as appropriate after considering each entity's characteristics and strategies. We expect that our ability to participate in potential acquisitions with, and our access to the experienced management team and industry contacts of, Penn Virginia will benefit us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. Under an omnibus agreement between us, Penn Virginia and our general partner, Penn Virginia and its affiliates, including PVG and our general partner, are restricted in their ability to engage in any coal-related business. See Item 13, "Certain Relationships and Related Transactions, and Director Independence—Transactions with Related Persons."

Partnership Distributions

Cash Distributions

We 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, we 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, we expect to pay quarterly distributions of at least $0.44 ($1.76 on an annualized basis) per common unit.

The following table reflects the allocation of total cash distributions paid by us during the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousand, except per unit data)		
Limited partner units	$76,536	$61,427	$50,018
General partner interest (2%)	1,562	1,254	1,021
Incentive distribution rights	11,551	4,273	910
Total cash distributions paid	$89,649	$66,954	$51,949
Total cash distributions paid per unit	$1.6660	$1.4750	$1.2413

Incentive Distribution Rights

In accordance with our partnership agreement, incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The minimum quarterly distribution is $0.25 per unit ($1.00 per unit on an annualized basis). Our 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 our general partner with or into such entity or the transfer of all or substantially all of our general partner's assets to another entity without the prior approval of our unitholders if the transferee agrees to be bound by the provisions of our partnership agreement. Prior to September 30, 2011, other transfers of incentive distribution rights will require the affirmative vote of holders of a majority of the outstanding common units. On or after September 30, 2011, the incentive distribution rights will be freely transferable. The incentive distribution rights are payable as follows:

If for any quarter:

- we have distributed available cash from operating surplus to our common unitholders in an amount equal to the minimum quarterly distribution; and
- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner in the following manner:

- First, 98% to all unitholders, and 2% to our general partner, until each unitholder has received a total of $0.275 per unit for that quarter;
- Second, 85% to all unitholders, and 15% to our general partner, until each unitholder has received a total of $0.325 per unit for that quarter;
- Third, 75% to all unitholders, and 25% to our general partner, until each unitholder has received a total of $0.375 per unit for that quarter; and
- Thereafter, 50% to all unitholders and 50% to our general partner.

Our quarterly distribution rate has exceeded $0.375 per unit since the distribution we paid in November 2006 with respect to the third quarter of 2006. Therefore, our general partner has received 50% of available cash in excess of $0.375 per unit since then.

Subordinated Units

Until November 14, 2006, we had a separate class of subordinated units representing limited partner interests in us, and the rights of holders of subordinated units to participate in distributions to limited partners were subordinated to the rights of the holders of our common units. On November 14, 2006, all of our subordinated units converted into common units on a one-for-one basis and no subordinated units remain outstanding.

Until May 22, 2007, we had Class B units, a separate class of subordinated units representing limited partner interests in us that were issued to PVG in connection with PVG's initial public offering, or the PVG IPO. On May 22, 2007, all of our Class B units automatically converted into common units on a one-for-one basis and no Class B units remain outstanding.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of our outstanding common units, our general partner has the right, which it may assign in whole or in part to any of its affiliates or us, but not the obligation, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons as of a record date to be selected by our general partner, on at least ten but not more than 60 days' notice, at a price not less than the then-current market price of our common units.

As a result of our general partner's right to purchase outstanding common units, a holder of common units may have his or her common units purchased at an undesirable time or price. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his or her units in the market.

As of February 28, 2008, PVG and its affiliates owned 19,805,025 common units, representing approximately 43% of our outstanding common units.

Certain Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including Penn Virginia and PVG), on the one hand, and us and our limited partners, on the other hand. Our general partner is controlled by PVG, which is in turn controlled by Penn Virginia. Accordingly, PVG (and Penn Virginia indirectly) has the ability to elect, remove and replace the directors and officers of our general partner. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners, Penn Virginia and PVG. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders.

Certain of the executive officers and non-independent directors of our general partner also serve as executive officers and directors of Penn Virginia or the general partner of PVG. Consequently, these directors and officers may encounter situations in which their fiduciary obligations to Penn Virginia or PVG, on the one hand, and us, on the other hand, are in conflict.

Limits on Fiduciary Responsibilities

Our partnership agreement limits the liability and reduces the fiduciary duties owed by our general partner to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions that might otherwise constitute breaches of our general partner's fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues about compliance with fiduciary duties or applicable law. For example, our partnership agreement permits our general partner to make a number of decisions in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Other provisions of the partnership agreement provide that our general partner's actions must be made in its reasonable discretion. These standards reduce the obligations to which our general partner would otherwise be held.

Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to us under the factors previously set forth. In determining whether a transaction or resolution is "fair and reasonable" our general partner may consider the interests of all parties involved, including its own. Unless our general partner has acted in bad faith, the action taken by our general partner shall not constitute a breach of its fiduciary duty. These standards reduce the obligations to which our general partner would otherwise be held.

In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partner and those other persons acted in good faith.

In order to become a limited partner of our partnership, a common unitholder is required to agree to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Revised Uniform Limited Partnership Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner or assignee to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

We are required to indemnify our general partner and its officers, directors, employees, affiliates, partners, members, agents and trustees to the fullest extent permitted by law against liabilities, costs and expenses incurred by our general partner or these other persons. This indemnification is required if our general partner or any of these persons acted in good faith and in a manner they reasonably believed to be in, or (in the case of a person other than our general partner) not opposed to, our best interests. Indemnification is required for criminal proceedings if our general partner or these other persons had no reasonable cause to believe their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it met these requirements concerning good faith and our best interests.

Competition

Coal and Natural Resource Management Segment

The coal industry is intensely competitive primarily as a result of the existence of numerous producers. Our 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 our lessees having significantly larger financial and operating resources than most of our lessees. Our 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 our coal and the prices that our 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 our low sulfur coal and the prices our 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.

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 our 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.

We experience competition in all of our natural gas midstream markets. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas. Many of our competitors have greater financial resources and access to larger natural gas supplies than do we.

Government Regulation and Environmental Matters

The operations of our 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.

Coal and Natural Resource Management Segment

General Regulation Applicable to Coal Lessees. Our 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, our lessees regularly have on-site inspections and violations during mining operations are not unusual in the industry, notwithstanding compliance efforts by our lessees. However, none of the violations to date, or the monetary penalties assessed, have been material to us or, to our knowledge, to our lessees. Although many new safety requirements have been instituted recently, we do not currently expect that future compliance will have a material adverse effect on us.

While it is not possible to quantify the costs of compliance by our 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 our lessees are contractually liable for all costs relating to their mining operations, including the costs of reclamation and mine closure. However, we do 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 our lessees. The possibility exists that new legislation or regulations may be adopted which have a significant impact on the mining operations of our lessees or their customers' ability to use coal and may require us, our 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 our business, both directly and indirectly. The CAA directly impacts our 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 our lessees' ability to sell coal, which could have a material effect on our 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, our 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 our coal could be affected, which could have an adverse effect on our 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 our coal, which could have an adverse effect on our 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 our lessees' coal sales, and thereby have an adverse effect on our 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 we "owned" or "controlled" the mine operator in such a way for liability to attach. Regulatory authorities may attempt to assign the liabilities of our coal lessees to another entity such as us if any of our lessees are not financially capable of fulfilling those obligations. To our knowledge, no such claims have been asserted against us to date. In conjunction with mining the property, our 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 our lessees' ability to produce coal, which could affect our 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. We could become liable under federal and state Superfund and waste management statutes if our 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. Our 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 our 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, our 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 our lessees obtaining the required mining permits to conduct their operations, which could in turn have an adverse effect on our 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 our 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 our lessees, it could have an adverse effect on our 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 our lessees could adversely impact our 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 our lessees' coal mining operations discharge could require more costly water treatment and could adversely affect our 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 our lessees' ability to develop new mines or could require our lessees to modify existing operations, which could have an adverse effect on our 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 our 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 our 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 our 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 our lessees' ability to mine coal from our properties in accordance with current mining plans.

Mine Health and Safety Laws. The operations of our 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 our lessees' operations, particularly for underground mines, and could affect the financial performance of our lessees' operations.

Implementing and complying with these new laws and regulations could adversely affect our lessees' coal production and could therefore have an adverse effect on our coal royalties revenues and our ability to make distributions to our unitholders.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, our 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, our 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 our 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, our lessees submit the necessary permit applications between 12 and 24 months before they plan to begin mining a new area. In our experience, permits generally are approved within 12 months after a completed application is submitted. In the past, our lessees have generally obtained their mining permits without significant delay. Our 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. Our 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 "—Coal and Natural Resource Management Segment—Clean Water Act."

OSHA. Our lessees and our own business are subject to 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.

Natural Gas Midstream Segment

General Regulation. Our natural gas gathering facilities generally are exempt from the Federal Energy Regulatory Commission's, or the FERC, jurisdiction under the Natural Gas Act of 1938, or the NGA, but FERC regulation nevertheless could significantly affect our gathering business and the market for our services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which our 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. Our 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. Our 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 our 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, our 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. Our operations in Oklahoma are regulated by the Oklahoma Corporation Commission, which prohibits us from charging any unduly discriminatory fees for our gathering services. We cannot predict whether our gathering rates will be found to be unjust, unreasonable or unduly discriminatory.

We are 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 our right as an owner of gathering facilities to decide with whom we contract 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 our 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. Our natural gas midstream operations are subject to the CAA and comparable state laws and regulations. See "—Coal and Natural Resource Management Segment—Air Emissions." These laws and regulations govern emissions of pollutants into the air resulting from the activities of our processing plants and compressor stations and also impose procedural requirements on how we conduct our natural gas midstream operations. Such laws and regulations may include requirements that we 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 we are required to obtain or utilize specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We 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. Our 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 we own or operate, regardless of whether such disposal or release occurred during or prior to our acquisition of such properties. See "—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," our natural gas midstream operations do generate wastes in the course of ordinary operations that may fall within the definition of a "hazardous substance."

Our 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 we believe 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 our facilities.

We currently own or lease numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas and NGLs. Although we believe 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, we 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. We have ongoing remediation projects underway at several sites, but we do not believe that the costs associated with such cleanups will have a material adverse impact on our operations or revenues.

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

OSHA. Our natural gas midstream operations are subject to OSHA. See "—Coal and Natural Resource Management Segment—OSHA."

Employees and Labor Relations

We do not have employees. To carry out our operations, our general partner and its affiliates employed 129 employees who directly supported our operations at December 31, 2007. Our general partner considers current employee relations to be favorable.

Available Information

Our internet address is http://www.pvresource.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 and Audit Committee Charter, and we will provide copies of such documents to any unitholder 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. All references in this Annual Report on Form 10-K to the "NYSE" refer to the New York Stock Exchange, and all reference to the "SEC" refer to the Securities and Exchange Commission.

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
Mbbl	one thousand barrels
Mbf..	one thousand board feet
Mcf	one thousand cubic feet
Mcfe..	one thousand cubic feet equivalent
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
NGL	natural gas liquid
NYMEX	New York Mercantile Exchange
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
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
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

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 Inherent in an Investment in Us

The amount of cash that we will be able to distribute on our common units principally depends upon the amount of cash we generate from our coal and natural resource management and natural gas midstream businesses.

Under the terms of our partnership agreement, we must pay our general partner's expenses and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash that we will be able to distribute each quarter to our partners principally depends upon the amount of cash we can generate from our coal and natural resource management and natural gas midstream businesses. The amount of cash we will generate will fluctuate from quarter to quarter based on, among other things:

- the amount of coal our lessees are able to produce;
- the price at which our lessees are able to sell the coal;
- our lessees' timely receipt of payment from their customers;
- the amount of natural gas transported in our gathering systems;
- the amount of throughput in our processing plants;
- the price of natural gas;
- the price of NGLs;

- the relationship between natural gas and NGL prices;
- the fees we charge and the margins we realize for our natural gas midstream services; and
- our hedging activities.

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

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

Because of these factors, we may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. The amount of cash that we have available for distribution depends primarily upon our 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, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record profits.

While we may incur debt to pay distributions to our unitholders, the agreements governing such debt may restrict or limit the distributions we can pay to our unitholders.

While we are permitted by our partnership agreements to incur debt to pay distributions to our unitholders, our payment of principal and interest on such indebtedness will reduce our cash available for distribution on our unitholders. Furthermore, our debt agreements, including our revolving credit facility and senior notes, contain covenants limiting our ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions to our partners. They also contain covenants requiring us not to exceed certain specified financial ratios. We are prohibited from making any distribution to our partners if such distribution would cause an event of default or otherwise violate a covenant under these agreements. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt," for more information about our revolving credit facility and senior notes.

Our unitholders do not elect our general partner or vote on our general partner's directors. The owner of our general partner owns a sufficient number of common units to allow it to prevent the removal of our general partner.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders do not have the ability to elect our general partner or the directors of our general partner and will have no right to elect our general partner or the directors of our general partner on an annual or other continuing basis in the future. The board of directors of our general partner, including our independent directors, is chosen by PVG, its sole member. Furthermore, if our public unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Our general partner may not be removed except upon the vote of the holders of at least two-thirds of the outstanding common units. Because PVG owns more than one-third of our outstanding units, our general partner currently cannot be removed without its consent. As a result of these provisions, the price at which our common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Our general partner may cause us to issue additional common units or other equity securities without your approval, which would dilute your ownership interests.

Our general partner may cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval. The issuance of additional common units or other equity securities of equal rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each common unit may decrease;
- the relative voting strength of each previously outstanding common unit may be diminished;
- the ratio of taxable income to distributions may increase; and
- the market price of the common units may decline.

The control of our general partner may be transferred to a third party who could replace our current management team, in either case, without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, PVG, the owner of our general partner, may transfer its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner and to control the decisions taken by the board of directors and officers.

You may not have limited liability if a court finds that unitholder action constitutes control of our business.

Under Delaware law, you could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders as a group to remove or replace our general partner, to approve some amendments to the partnership agreement or to take other action under our partnership agreement constituted participation in the "control" of our business. Additionally, the limitations on the liability of holders of limited partner interests for the liabilities of a limited partnership have not been clearly established in many jurisdictions.

Furthermore, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Our partnership agreement restricts the rights of unitholders owning 20% or more of our units.

Our unitholders' voting rights are restricted by the provision in our partnership agreement generally providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of our management. As a result, the price at which our common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

We may issue additional limited partner interests or other equity securities, which may increase the risk that we will not have sufficient available cash to maintain or increase our cash distribution level.

We have wide latitude to issue additional limited partner interests on the terms and conditions established by our general partner. If we have to pay distributions on additional limited partner interests, we may not be able to maintain or increase our quarterly cash distribution per unit.

Risks Related to Our Coal and Natural Resource Management Business

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

We depend on our lessees to effectively manage their operations on our properties. Our 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 our lessees do not manage their operations well, their production could be reduced, which would result in lower coal royalties revenues to us and could adversely affect our ability to make our quarterly distributions.

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

Our coal royalties revenues are largely dependent on the level of production from our coal reserves achieved by our lessees. The level of our lessees' production is subject to operating conditions or events that may increase our lessees' cost of mining and delay or halt production at particular mines for varying lengths of time and that are beyond their or our 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 our reserves could reduce our coal royalties revenues and adversely affect our ability to make our quarterly distributions. In addition, our coal royalties revenues are based upon sales of coal by our lessees to their customers. If our 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 our cash flow to be adversely affected and could adversely affect our ability to make our quarterly distributions.

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

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

We depend on a limited number of primary operators for a significant portion of our coal royalties revenues and the loss of or reduction in production from any of our major lessees would reduce our coal royalties revenues.

We depend on a limited number of primary operators for a significant portion of our coal royalties revenues. In 2007, five primary operators, each with multiple leases, accounted for 65% of our coal royalties revenues and 11% of our total consolidated revenues. If any of these operators enters bankruptcy or decides to cease operations or significantly reduces its production, our coal royalties revenues would be reduced.

A failure on the part of our lessees to make coal royalty payments could give us the right to terminate the lease, repossess the property or obtain liquidation damages and/or enforce payment obligations under the lease. If we repossessed any of our properties, we would seek to find a replacement lessee. We may not be able to find a replacement lessee and, if we find a replacement lessee, we 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 we enter 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 us 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.

Our coal business will be adversely affected if we are unable to replace or increase our coal reserves through acquisitions.

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

Our lessees could satisfy obligations to their customers with coal from properties other than ours, depriving us of the ability to receive amounts in excess of the minimum coal royalties payments.

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

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

Our 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 our lessees to supply coal to their customers. Our lessees' transportation providers may face difficulties in the future and impair the ability of our lessees to supply coal to their customers, thereby resulting in decreased coal royalties revenues to us.

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

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

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

Our estimates of our coal reserves may vary substantially from the actual amounts of coal our lessees may be able to economically recover. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our 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 our 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 us.

Any change in fuel consumption patterns by electric power generators away from the use of coal could affect the ability of our lessees to sell the coal they produce and thereby reduce our 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. We believe 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—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 our lessees to sell the coal they produce and thereby reduce our 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 our 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 our lessees produce and thereby reducing our coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—Coal and Natural Resource Management Segment—Air Emissions."

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

Mine operators, including our 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 our 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 our lessees' ability to economically conduct their mining operations. Limitations on our 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 our coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—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 our 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, our 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 our 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 our lessees for the Republic No. 2 Mine and enjoined our 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 our coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—Coal and Natural Resource Management Segment—Clean Water Act," for more information about the litigation described above.

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

Our 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. Our 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 our lessees' mining operations, either through direct impacts such as new requirements impacting our 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 our coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—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, we do not believe violations by our 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. Our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If our 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, our coal royalties revenues and our 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—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 our lessees' coal production and could therefore have an adverse effect on our coal royalties revenues and our ability to make distributions.

Risks Related to Our Natural Gas Midstream Business

The success of our natural gas midstream business depends upon our ability to find and contract for new sources of natural gas supply.

In order to maintain or increase system throughput levels on our gathering systems and asset utilization rates at our processing plants, we must contract for new natural gas supplies. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include the level of drilling activity creating new gas supply near our gathering systems, our success in contracting for existing natural gas supplies that are not committed to other systems and our ability to expand and increase the capacity of our systems. We 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. We have no control over the level of drilling activity in our areas of operations, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, we have 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.

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

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

We are subject to significant risks due to fluctuations in natural gas commodity prices. During 2007, we generated a majority of our gross processing margin from two types of contractual arrangements under which our 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—Natural Gas Midstream Segment."

Virtually all of the natural gas gathered on our Crescent System and Hamlin System is contracted under percentage-of-proceeds arrangements. The natural gas gathered on our Beaver System is contracted primarily under either percentage-of proceeds or gas purchase/keep-whole arrangements. Under both types of arrangements, we provide gathering and processing services for natural gas received. Under percentage-of-proceeds arrangements, we generally sell the NGLs produced from the processing operations and the remaining residue gas at market prices and remit 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 our results of operations. Under gas purchase/keep-whole arrangements, we generally buy natural gas from producers based upon an index price and then sell 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 our results of operations.

In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. The markets and prices for residue gas and NGLs depend upon factors beyond our 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 our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing the risks of being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing operations. We may encounter difficulties integrating these acquisitions with our 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, we 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, our capitalization and results of operations may change significantly following an acquisition. Future acquisitions might not generate increases in our cash distributions to our unitholders.

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

One of the ways we may grow our 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 our control and require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule, or at all, or at the budgeted cost. Moreover, our 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 our estimates. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we 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 our expected investment return, which could adversely affect our financial position or results of operations and our ability to make distributions.

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

The construction of additions to our existing gathering assets may require us to obtain new rights-of-way before constructing new pipelines. We may be unable to obtain rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us 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 our cash flows could be reduced.

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

We are subject to risk of loss resulting from nonpayment or nonperformance by our natural gas midstream customers. We depend on a limited number of customers for a significant portion of our natural gas midstream revenues. In 2007, three of our natural gas midstream customers accounted for 53% of our natural gas midstream revenues and 42% of our total consolidated revenues. Any nonpayment or nonperformance by our natural gas midstream customers would reduce our cash flows.

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

We are 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 our natural gas midstream facilities. Similarly, if additional shippers begin transporting volumes of residue gas and NGLs on interconnecting pipelines, our allocations in these pipelines could be reduced. Any reduction in volumes gathered and processed in our facilities could adversely affect our revenues and cash flows.

Natural gas derivative transactions may limit our potential gains and involve other risks.

In order to manage our exposure to price risks in the marketing of our natural gas and NGLs, we periodically enter into natural gas and NGL 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. However, in connection with acquisitions, sometimes our hedges are for longer periods. These hedging transactions may limit our 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, we 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 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 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.

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

Our 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 our related operations. Our 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 our operations. We are not fully insured against all risks incident to our natural gas midstream business. We do not have property insurance on all of our underground pipeline systems that would cover damage to the pipelines. We are 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 our operations and financial condition.

Federal, state or local regulatory measures could adversely affect our natural gas midstream business.

We own and operate an 11-mile interstate natural gas pipeline that, pursuant to the NGA, is subject to the jurisdiction of the FERC. The FERC has granted us 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 we 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.

Our 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 our gathering business and the market for our services. For a more detailed discussion of how regulatory measures affect our natural gas gathering systems, see Item 1, "Business—Government Regulation and Environmental Matters—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.

Our natural gas midstream business is subject to extensive environmental regulation.

Many of the operations and activities of our 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 our facilities and the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or the prior owners of our natural gas midstream business or locations to which we or they have sent wastes for disposal. These laws and regulations can restrict or impact our business activities in many ways, including restricting the manner in which we dispose 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 our natural gas midstream business due to our handling of natural gas and other petroleum products, air emissions related to our natural gas midstream operations, historical industry operations, waste disposal practices and the use by the prior owners of our natural gas midstream business of natural gas flow meters containing mercury. For example, an accidental release from one of our pipelines or processing facilities could subject us 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 our compliance costs and the cost of any remediation that may become necessary. We 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—Natural Gas Midstream Segment."

Risks Related to Conflicts of Interest

Potential conflicts of interest may arise among our general partner, its affiliates and us. Our general partner has limited fiduciary duties to us and our unitholders, which may permit it to favor its own interests to the detriment of us and our unitholders.

Penn Virginia and its affiliates, including PVG, own an approximately 42% limited partner interest in us and own and control our general partner. Conflicts of interest may arise between our general partner and its affiliates (including Penn Virginia and PVG), on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- Our general partner is allowed to take into account the interests of parties other than us, such as Penn Virginia and PVG, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.
- Our general partner may limit its liability and reduce its fiduciary duties under our partnership agreement, while also restricting the remedies available to our unitholders for actions that, without these limitations and reductions, might constitute breaches of fiduciary duty. As a result of purchasing units, our unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.

- Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available to be distributed to our unitholders.
- Our general partner controls the enforcement of obligations owed to us by it and its affiliates.
- Our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution.
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The fiduciary duties of our general partner's officers and directors may conflict with those of PVG's general partner, and our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to us.

Our general partner's officers and directors have fiduciary duties to manage our business in a manner beneficial to us and our unitholders and the owner of our general partner, PVG. However, three of our general partner's eight directors and three of its five officers are also directors or officers of PVG's general partner, which has fiduciary duties to manage the business of PVG in a manner beneficial to PVG and its unitholders, including Penn Virginia. Consequently, these directors and officers may encounter situations in which their fiduciary obligations to us on the one hand, and PVG, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

In addition, our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions that might otherwise constitute a breach of our general partner's fiduciary duties owed to unitholders. By purchasing our units, you are treated as having consented to various actions contemplated in the partnership agreement and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.

We may face conflicts of interest in the allocation of administrative time among Penn Virginia's business, PVG's business and our business.

Our general partner shares administrative personnel with Penn Virginia and PVG's general partner to operate Penn Virginia's business, PVG's business and our business. Our general partner's officers, who are also the officers of PVG's general partner and/or Penn Virginia, will have responsibility for overseeing the allocation of time spent by administrative personnel on our behalf and on behalf of PVG and/or Penn Virginia. These officers face conflicts regarding these time allocations that may adversely affect our results of operations, cash flows and financial condition. It is unlikely that these allocations will be the result of arms-length negotiations among Penn Virginia, PVG's general partner and our general partner.

Our general partner has a call right that may require you to sell your common units at an undesirable time or price.

If at any time more than 80% of our outstanding units are owned by our general partner and its affiliates, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the remaining units held by unaffiliated persons at a price equal to the greater of (x) the average of the daily closing prices of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (y) the highest price paid by our general partner or any of its affiliates for common units during the 90 day period preceding the date such notice is first mailed. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your common units. Affiliates of our general partner currently own approximately 43% of our outstanding common units.

Our general partner may mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without prior approval of our unitholders.

Our general partner may mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without prior approval of our unitholders. If our general partner at any time decided to incur debt and secures its obligations or indebtedness by all or substantially all of our assets, and if our general partner is unable to satisfy such obligations or repay such indebtedness, the lenders could seek to foreclose on our assets. The lenders may also sell all or substantially all of our assets under such foreclosure or other realization upon those encumbrances without prior approval of our unitholders, which would adversely affect the price of our common units

Tax Risks to Our Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, or IRS, on this or any other matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in our anticipated cash flow and likely cause a substantial reduction in the value of our common units. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we are subject to a new entity-level tax on the portion of our income that is generated in Texas. Specifically, the Texas margin tax is imposed at a maximum effective rate of 0.7% of our federal gross income apportioned to Texas. Imposition of such a tax on us by Texas, or any other state, will reduce the cash available for distribution to our unitholders.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Although the currently proposed legislation would not appear to affect our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

If the IRS contests the federal income tax positions that we take, it may adversely affect the market for our common units, and the costs of any contest will reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may disagree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income, whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the tax liability that results from the taxation of your share of our taxable income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and the adjusted tax basis in those common units. Prior distributions to you in excess of the total net taxable income allocated to you, which decreased your tax basis in your common units, will, in effect, become taxable income to you if the common units are sold at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you. In addition, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, a significant amount of our income allocated to organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units.

We are registered as a tax shelter. This may increase the risk of an IRS audit of us or a unitholder.

We are registered with the IRS as a "tax shelter." Our tax shelter registration number is 01309000001. The IRS requires that some types of entities, including some partnerships, register as "tax shelters" in response to the perception that they claim tax benefits that the IRS may believe to be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in our unitholders' tax returns and may lead to audits of unitholders' tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned common units, such unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourself using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of our common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the technical termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A sale or exchange would occur, for example, if we sold our business or merged with another company, or if any of our unitholders, including Penn Virginia, PVG or any of their affiliates, sold or transferred their partner interests in us. While we would continue our existence as a Delaware limited partnership, our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A technical termination would not effect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a technical termination occurred.

You will likely be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if you do not reside in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. It is your responsibility to file all United States federal, state and local tax returns that may be required of you.

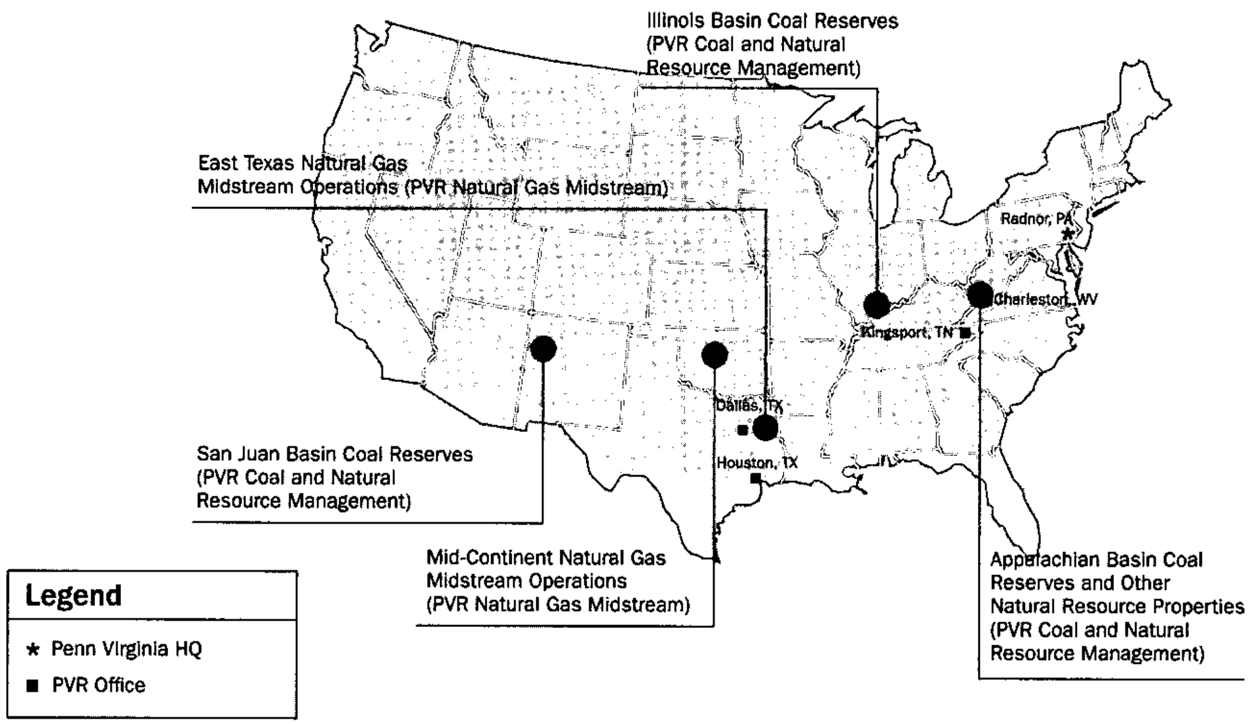
Item 1B *Unresolved Staff Comments*

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 coal reserves and related infrastructure investments and our 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 coal reserves in accordance with standards generally accepted in the coal and natural resource management and natural gas midstream industries.

Facilities

Our general partner provides all of our office space, except for a field office that we own near Charleston, West Virginia.

Coal Reserves and Production

As of December 31, 2007, we 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. Our 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 our coal reserves are classified as proven and probable reserves. Proven and probable reserves are defined as follows:

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

In areas where geologic conditions indicate potential inconsistencies related to coal reserves, we perform additional 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 our 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 reserves." Included among the factors that influence profitability are the existing market price, coal quality and operating costs.

Our lessees mine coal using both underground and surface methods. As of December 31, 2007, our lessees operated 27 surface mines and 33 underground mines. Approximately 53% of the coal produced from our properties in 2007 came from underground mines and 47% came from surface mines. Most of our lessees use the continuous mining method in all of their underground mines located on our properties. In continuous mining, main airways and transportation entries are developed and remote-controlled continuous miners extract coal from "rooms," leaving "pillars" to support the roof. Shuttle cars transport coal to a conveyor belt for transportation to the surface. In several underground mines, our lessees use two continuous miners running at the same time, also known as a supersection, to improve productivity and reduce unit costs.

Two of our lessees use the longwall mining method to mine underground reserves. Longwall mining uses hydraulic jacks or shields, varying from four feet to twelve feet in height, to support the roof of the mine while a mobile cutting shearer advances through the coal. Chain conveyors then move the coal to a standard deep mine conveyor belt system for delivery to the surface. Continuous mining is used to develop access to long rectangular panels of coal that are mined with longwall equipment, allowing controlled caving behind the advancing machinery. Longwall mining is typically highly productive when used for large blocks of medium to thick coal seams.

Surface mining methods used by our lessees include auger and highwall mining to enhance production, improve reserve recovery and reduce unit costs. On our San Juan Basin property, a combination of the dragline and truck-and-shovel surface mining methods is used to mine the coal. Dragline and truck-and-shovel mining uses large capacity machines to remove overburden to expose the coal seams. Wheel loaders then load the coal in haul trucks for transportation to a loading facility.

Our lessees' customers are primarily electric utilities, also referred to as "steam" markets. Coal produced from our properties is transported by rail, barge and truck, or a combination of these means of transportation. Coal from the Virginia portion of the Wise property and the Buchanan property is primarily shipped to electric utilities in the Southeast by the Norfolk Southern railroad. Coal from the Kentucky portion of the Wise property is primarily shipped to electric utilities in the Southeast by the CSX railroad. Coal from the Coal River and Spruce Laurel properties is shipped to steam and metallurgical customers by the CSX railroad, by barge along the Kanawha River and by truck or by a combination thereof. Coal from the Northern Appalachia properties is shipped by barge on the Monongahela River, by truck and by the CSX and Norfolk Southern railroads. Coal from the Illinois Basin properties is shipped by barge on the Green River and by truck. Coal from the San Juan Basin property is shipped to steam markets in New Mexico and Arizona by the Burlington Northern Santa Fe railroad. All of our properties contain and have access to numerous roads and state or interstate highways.

The following table shows our most important coal producing seams by property:

Area	Property	State	Producing Mine Types	Seam Name	Height Range (ft.)
Central Appalachia	Wise	Virginia, Kentucky	Surface, Underground	Parsons	1.00 - 6.00
				Phillips	1.50 - 6.00
				Low Splint	1.00 - 5.50
				Taggart/Marker	1.50 - 9.00
				U. Wilson	1.50 - 5.50
				Kelly/Imboden	1.00 - 7.50
	Buchanan	Virginia	Surface, Underground	Hagy	2.50 - 3.50
				Splashdam	2.50 - 4.00
	Wayland	Kentucky	Underground	U. Elkhorn No. 2	2.33 - 4.00
	Coal River, Fields Creek	West Virginia	Surface, Underground	Stockton	4.00 -12.00
				Coalburg	1.00 - 11.00
				Winifrede	1.00 - 7.00
				Chilton	1.00 - 4.00
				Cedar Grove	1.00 - 5.50
				No. 2 Gas	1.50 - 8.00
	Toney Fork	West Virginia	Surface	Coalburg	5.00 -16.00
	Spruce Laurel	West Virginia	Underground	Coalburg	3.00 - 6.00
				Winifrede	2.50 - 4.00
				Chilton	2.50 - 4.00
				Alma	2.50 - 7.00
Northern Appalachia	Federal	West Virginia	Underground	Pittsburgh	6.50 - 9.50
	Upshur	West Virginia	Surface, Underground	Redstone	3.00 - 6.50
				Pittsburgh	2.00 - 9.00
San Juan Basin	Lee Ranch	New Mexico	Surface	Cleary Group Seams	8.00 -16.00
Illinois Basin	Green River	Kentucky	Surface, Underground	KY No. 9	3.00 - 5.00
	Allied	Kentucky	Underground	KY No. 9	3.00 – 5.00
	Knight Hawk	Illinois	Underground	Herrin No. 6	5.00 – 8.00

The following tables set forth production data and reserve information with respect to each of our 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

Of the approximately 818 million tons of proven and probable coal reserves to which we had rights as of December 31, 2007, we owned the mineral interests and the related surface rights to 448 million tons, or 55%, and we owned only the mineral interests to 196 million tons, or 24%. We leased the mineral rights to the remaining 174 million tons, or 21%, from unaffiliated third parties and, in turn, subleased these reserves to our lessees. For the reserves we lease from third parties, we pay royalties to the owner based on the amount of coal produced from the leased reserves. Additionally, in some instances, we purchase surface rights or otherwise compensate surface right owners for mining activities on their properties. In 2007, our aggregate expenses to third-party surface and mineral owners were $5.5 million.

The following table sets forth the coal reserves we own and lease with respect to each of our coal properties as of December 31, 2007:

Property	Owned	Leased	Total Controlled
		(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 our coal reserve activity for each of our 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

Our coal reserve estimates are prepared from geological data assembled and analyzed by our general partner's or its affiliates' geologists and engineers. These estimates are compiled using geological data taken from thousands of drill holes, geophysical logs, adjacent mine workings, outcrop prospect openings and other sources. These estimates also take into account legal, qualitative, technical and economic limitations that may keep coal from being mined. Coal reserve estimates will change from time to time due to mining activities, analysis of new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods and other factors.

We classify low sulfur coal as coal with a sulfur content of less than 1.0%, medium sulfur coal as coal with a sulfur content between 1.0% and 1.5% and high sulfur coal as coal with a sulfur content of greater than 1.5%. Compliance coal is that portion of low sulfur coal that meets compliance standards for the CAA. As of December 31, 2007, approximately 26% of our reserves met compliance standards for the CAA and 39% were low sulfur. The following table sets forth our estimate of the sulfur content and the typical clean coal quality of our recoverable coal reserves at December 31, 2007:

		Sulfur Content					Typical Clean Coal Quality		
		Reserves as of December 31, 2007					Heat Content		
Property	Compliance (1)	Low Sulfur (2)	Medium Sulfur	High Sulfur	Sulfur Unclassified	Total	BTU per Pound (3)	Sulfur (%)	Ash (%)
				(tons in millions)					
Central Appalachia	213.7	288.8	156.8	30.2	93.5	569.3	14,044	1.03	6.46
Northern Appalachia	—	—	—	29.7	—	29.7	12,900	2.58	8.80
Illinois Basin	—	—	—	168.5	—	168.5	11,034	2.39	8.32
San Juan Basin	—	31.1	15.2	4.6	—	50.9	9,200	0.89	17.80
Total	213.7	319.9	172.0	233.0	93.5	818.4			

(1) Compliance coal is low sulfur coal which, when burned, emits less than 1.2 pounds of sulfur dioxide per million BTU. Compliance coal meets the sulfur dioxide emission standards imposed by Phase II of the CAA without blending in other

coals or using sulfur dioxide reduction technologies. Compliance coal is a subset of low sulfur coal and is, therefore, also reported within the amounts for low sulfur coal.

(2) Includes compliance coal.

(3) As-received BTU per pound includes the weight of moisture in the coal on an as sold basis.

The following table shows the proven and probable coal reserves we lease to mine operators by property:

	Proven and Probable Reserves as of December 31, 2007		
Property	**Total Controlled**	**Leased to Operators**	**Percentage Leased**
		(tons in millions)	
Central Appalachia	569.3	491.8	86%
Northern Appalachia	29.7	29.3	99%
Illinois Basin	168.5	111.8	66%
San Juan Basin	50.9	50.9	100%
Total	818.4	683.8	84%

Other Natural Resource Management Assets

Coal Preparation and Loading Facilities

We generate coal services revenues from fees we charge to our lessees for the use of our 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 our reserves.

Timber and Oil and Gas Royalty Interests

We own approximately 220,000 acres of forestland in Kentucky, Virginia and West Virginia. Approximately 28% of our forestland is located on the 62,000 acres in West Virginia that we 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 our forestland acquisition. The balance of our forestland is located on properties that also contain our coal reserves.

We own 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 our oil and gas royalty interests are associated with the leases of property in eastern Kentucky and southwestern Virginia that we acquired in October 2007. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments," for a discussion of our oil and gas royalty interest acquisition.

Natural Gas Midstream Systems

Our 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. Our natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. We own, lease or have rights-of-way to the properties where the majority of our natural gas midstream facilities are located.

The following table sets forth information regarding our 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)	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.

Beaver/Perryton System

General. The Beaver/Perryton System is a natural gas gathering system stretching over ten counties in the Anadarko Basin of the panhandle of Texas and Oklahoma. The system consists of approximately 1,421 miles of natural gas gathering pipelines, ranging in size from two to 16 inches in diameter, and the Beaver natural gas processing plant. Included in the system is an 11-mile, 10-inch diameter, FERC-jurisdictional residue line.

The Beaver/Perryton System is comprised of a number of major gathering systems and sixteen related compressor stations that gather natural gas, directly or indirectly, to the Beaver plant in Beaver County, Oklahoma. These include the Beaver, Perryton, Spearman, Wolf Creek/Kiowa Creek and Ellis systems. These gathering systems are located in Beaver, Ellis and Harper Counties in Oklahoma and Hansford, Hutchinson, Lipscomb, Ochiltree and Roberts Counties in Texas.

The Beaver natural gas processing plant has 100 MMcfd of inlet gas capacity. The plant is capable of operating in high ethane recovery mode or in ethane rejection mode and has instrumentation allowing for unattended operation 16 hours per day.

We expect to place a new Spearman natural gas processing plant in service by April 2008. 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. We plan to expand the Spearman gathering system to connect it to the Perryton and Wolf Creek/Kiowa Creek gathering systems. This expansion will provide flexibility and allow for maximum utilization of both the Beaver and Spearman natural gas processing plants.

The Spearman natural gas processing plant will have 60 MMcfd of inlet capacity. The plant will be capable of operating in high ethane recovery mode or in ethane rejection mode and will have instrumentation allowing for unattended operation 16 hours per day. In conjunction with the construction of the Spearman plant, three new gas compressor stations have been constructed on the Spearman gathering system. These compressor stations will allow for more efficient operation of the Spearman system and provide lower wellhead pressures.

Natural Gas Supply. The supply in the Beaver/Perryton System comes from approximately 171 producers pursuant to 333 contracts. The average gas quality on the Beaver/Perryton System for 2007 was 3.6 gallons of NGLs per delivered Mcf.

Markets for Sale of Natural Gas and NGLs. The residue gas from the Beaver plant can be delivered into the Northern Natural Gas, Southern Star Central Gas or ANR Pipeline Company pipelines for sale or transportation to market. The NGLs produced at the Beaver plant are delivered into ONEOK Hydrocarbon's pipeline system for transportation to and fractionation at ONEOK's Conway fractionator.

The residue gas from the Spearman plant will be delivered into Northern Natural Gas pipelines for sale or transportation to market. The NGLs produced at the Spearman plant will be delivered into MAPCO's (Mid-America Pipeline Company) pipeline system. MAPCO's pipeline system has the flexibility of delivering the NGLs to either Mont Belvieu or Conway for fractionation.

Crescent System

General. The Crescent System is a natural gas gathering system stretching over seven counties within central Oklahoma's Sooner Trend. The system consists of approximately 1,680 miles of natural gas gathering pipelines, ranging in size from two to 10 inches in diameter, and the Crescent gas processing plant located in Logan County, Oklahoma. Fourteen compressor stations are operating across the Crescent System.

The Crescent plant is a NGL recovery plant with current capacity of approximately 40 MMcfd. The Crescent facility also includes a gas engine-driven generator which is routinely operated, making the plant self-sufficient with respect to electric power. The cost of fuel (residue gas) for the generator is borne by the producers under the terms of their respective gas contracts.

Natural Gas Supply. The gas supply on the Crescent System is primarily gas associated with the production of oil or "casinghead gas" from the mature Sooner Trend. Wells in this region producing casinghead gas are generally characterized as low volume, long-lived producers of gas with large quantities of NGLs. The supply in the Crescent System comes from approximately 259 producers pursuant to 409 contracts. The average gas quality on the Crescent System for 2007 was 5.5 gallons of NGLs per delivered Mcf.

Markets for Sale of Natural Gas and NGLs. The Crescent plant's connection to the Enogex and ONEOK Gas Transportation pipelines for residue gas and the ONEOK Hydrocarbon pipeline for NGLs give the Crescent System access to a variety of market outlets.

Hamlin System

General. The Hamlin System is a natural gas gathering system stretching over eight counties in West Central Texas. The system consists of approximately 503 miles of natural gas gathering pipelines, ranging in size from two to 12 inches in diameter and with current capacity of approximately 20 MMcfd, and the Hamlin natural gas processing plant located in Fisher County, Texas. Eight compressor stations are operating across the system.

Natural Gas Supply. The gas on the Hamlin System is primarily gas associated with the production of oil or "casinghead gas." The supply on the Hamlin System comes from approximately 109 producers pursuant to 138 contracts. The average gas quality on the Hamlin System for 2007 was 8.9 gallons of NGLs per delivered Mcf.

Markets for Sale of Natural Gas and NGLs. The Hamlin System delivers the residue gas from the Hamlin plant into the Enbridge or Atmos pipelines. The NGLs produced at the Hamlin plant are delivered into TEPPCO's pipeline system.

Arkoma System

General. The Arkoma System is a stand-alone gathering operation in southeastern Oklahoma's Arkoma Basin and is comprised of three separate gathering systems, two of which are 100% owned with the third system being 49% owned. We operate and maintain all three systems. The Arkoma System consists of a total of approximately 78 miles of natural gas gathering pipelines, ranging in size from three to 12 inches in diameter. Three compressor stations are operating across the Arkoma System.

Natural Gas Supply. The supply on the Arkoma System comes from approximately 18 producers pursuant to 32 contracts.

Markets for Sale of Natural Gas and NGLs. The Arkoma System lines deliver gas into the Ozark, Noram and NGPL pipelines.

Crossroads System

General. We are currently constructing a new natural gas gathering system located in the southeast portion of Harrison County, Texas (the Crossroads System). 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.

The Crossroads natural gas processing plant will have 80 MMcfd of inlet capacity. The plant will be capable of operating in high ethane recovery mode or in ethane rejection mode and will have instrumentation allowing for unattended operation 16 hours per day.

Natural Gas Supply. The gas on the Crossroads System will originate from the Bethany Field from two producers pursuant to two contracts. The average gas quality on the Crossroads System is expected to be 3.1 gallons of NGLs per delivered Mcf.

Markets for Sale of Natural Gas and NGLs. The Crossroads System will deliver the residue gas from the Crossroads plant into the CenterPoint Energy pipeline for sale or transportation to market. The NGLs produced at the Crossroads plant will be delivered into Panola Pipeline for transportation to Mont Belvieu for fractionation.

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 Unitholder Matters and Issuer Purchases of Equity Securities***

Market Information

Our common units are traded on the NYSE under the symbol "PVR." The high and low sales prices (composite transactions) for each fiscal quarter in 2007 and 2006 were as follows:

Quarter Ended	High	Low
December 31, 2007	$29.54	$23.71
September 30, 2007	$32.90	$23.58
June 30, 2007	$31.69	$26.69
March 31, 2007	$28.89	$24.56
December 31, 2006	$27.10	$23.34
September 30, 2006	$28.10	$23.01
June 30, 2006	$32.46	$22.90
March 31, 2006	$31.03	$26.27

Equity Holders

As of February 22, 2008, there were 214 record holders and approximately 23,300 beneficial owners (held in street name) of our common units.

Distributions

For the year ended December 31, 2007, we paid cash distributions of $1.66 per common and Class B unit. The quarterly cash distributions paid in 2007 and 2006 were as follows:

Period Covered by Distribution	Record Date	Payment Date	Amount Per Unit
Third quarter 2007	November 5, 2007	November 14, 2007	$0.4300
Second quarter 2007	August 6, 2007	August 14, 2007	$0.4200
First quarter 2007	May 4, 2007	May 15, 2007	$0.4100
Fourth quarter 2006	February 5, 2007	February 14, 2007	$0.4000
Third quarter 2006	November 3, 2006	November 14, 2006	$0.4000
Second quarter 2006	August 2, 2006	August 12, 2006	$0.3750
First quarter 2006	May 3, 2006	May 13, 2006	$0.3500
Fourth quarter 2005	February 4, 2006	February 14, 2006	$0.3500

If cash distributions per unit exceed $0.275 in any quarter, our general partner will receive a higher percentage of the cash we distribute in excess of that amount in increasing percentages up to 50%. See Item 1, "Business—Partnership Distributions—Incentive Distribution Rights." On February 14, 2008, we paid a cash distribution with respect to the fourth quarter of 2007 of $0.44 per common unit, exceeding the $0.275 threshold. For the remainder of 2008, we expect to pay quarterly cash distributions of at least $0.44 per common unit, or $1.76 per common unit on an annualized basis.

There is no guarantee that we will pay quarterly cash distributions on our common units in any quarter, and we will be prohibited from making any distributions to our unitholders if it would cause an event of default under our revolving credit facility. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

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 (1)	2004	2003
	(in thousands, except per unit data)				
Revenues	$ 549,445	$ 517,891	$ 446,348	$ 75,630	$ 55,642
Expenses	$ 431,720	$ 415,071	$ 368,258	$ 35,111	$ 29,082
Operating income	$ 117,725	$ 102,820	$ 78,090	$ 40,519	$ 26,560
Net income	$ 56,623	$ 73,928	$ 51,161	$ 34,315	$ 22,690
Net income per limited partner unit, basic and diluted	$ 0.96	$ 1.56	$ 1.22	$ 0.93	$ 0.62
Total assets	$ 931,279	$ 714,023	$ 657,879	$ 284,435	$ 259,892
Long-term debt	$ 399,153	$ 207,214	$ 246,846	$ 112,926	$ 90,286
Cash flows provided by operating activities	$ 127,824	$ 107,344	$ 93,172	$ 54,782	$ 41,077
Distributions paid	$ 89,649	$ 66,954	$ 51,949	$ 39,191	$ 36,708
Distributions paid per unit	$ 1.66	$ 1.48	$ 1.24	$ 1.06	$ 1.03

(1) 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 Resource Partners, L.P. 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 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 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. Both in our current limited partnership form and in our previous corporate form, we have managed coal properties since 1882. We currently conduct operations in two business segments: (1) coal and natural resource management and (2) natural gas midstream. Our operating income was $117.7 million in 2007, compared to $102.8 million in 2006 and $78.1 million in 2005. In 2007, our coal and natural resource management segment contributed $68.8 million, or 58%, to operating income, and our natural gas midstream segment contributed $48.9 million, or 42%, to operating income. The following table presents a summary of certain financial information relating to our segments:

	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
		(in thousands)	
For the Year Ended December 31, 2007:			
Revenues	$ 111,639	$ 437,806	$ 549,445
Cost of midstream gas purchased	-	343,293	343,293
Operating costs and expenses	20,138	26,777	46,915
Depreciation, depletion and amortization	22,690	18,822	41,512
Operating income	$ 68,811	$ 48,914	$ 117,725
For the Year Ended December 31, 2006:			
Revenues	$ 112,981	$ 404,910	$ 517,891
Cost of midstream gas purchased	-	334,594	334,594
Operating costs and expenses	19,138	23,846	42,984
Depreciation, depletion and amortization	20,399	17,094	37,493
Operating income	$ 73,444	$ 29,376	$ 102,820
For the Year Ended December 31, 2005:			
Revenues	$ 95,755	$ 350,593	$ 446,348
Cost of midstream gas purchased	-	303,912	303,912
Operating costs and expenses	16,121	17,597	33,718
Depreciation, depletion and amortization	17,890	12,738	30,628
Operating income	$ 61,744	$ 16,346	$ 78,090

Coal and Natural Resource Management Segment

As of December 31, 2007, we 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 our 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. We enter into long-term leases with experienced, third-party mine operators, providing them the right to mine our coal reserves in exchange for royalty payments. We actively work with our lessees to develop efficient methods to exploit our reserves and to maximize production from our properties. We do not operate any mines. In 2007, our lessees produced 32.5 million tons of coal from our properties and paid us coal royalties revenues of $94.1 million, for an average royalty per ton of $2.89. Approximately 81% of our coal royalties revenues in 2007 and 84% of our coal royalties revenues in 2006 were derived from coal mined on our 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 our coal royalties revenues for the respective periods was derived from coal mined on our properties under leases containing fixed royalty rates that escalate annually. In 2007, five lessees accounted for 65% of our coal royalties revenues and 11% of our total consolidated revenues.

Coal royalties are impacted by several factors that we generally cannot control. The number of tons mined annually is determined by an operator's mining efficiency, labor availability, geologic conditions, access to capital, ability to market coal and ability to arrange reliable transportation to the end-user. New legislation or regulations have been or may be adopted which may have a significant impact on the mining operations of our lessees or their customers' ability to use coal and which may require us, our lessees or our lessee's customers to change operations significantly or incur substantial costs. See Item 1A, "Risk Factors." To a lesser extent, coal prices also impact coal royalties revenues. Generally, as coal prices change, our average royalty per ton also changes because the majority of our lessees pay royalties based on the gross sales prices of the coal mined. Most of our coal is sold by our lessees under contracts with a duration of one year or more; therefore, changes to our average royalty occur as our lessees' contracts are renegotiated. Coal prices, especially in Central Appalachia where the majority of our coal is produced, increased significantly from the beginning of 2005 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.

We also earn revenues from the provision of fee-based coal preparation and loading services, from the sale of standing timber on our properties, from oil and gas royalty interests we own and from coal transportation, or wheelage, fees.

Our management continues to focus on acquisitions that increase and diversify our sources of cash flow. During 2007, we acquired 60 million tons of coal reserves in two acquisitions for an aggregate purchase price of approximately $52 million. In addition, in 2007, we acquired approximately 62,000 acres of forestland in West Virginia for a purchase price of approximately $93 million to expand our existing timber business. In 2007, we 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 our existing oil and gas royalty interest business. For a more detailed discussion of our acquisitions, see "—Acquisitions and Investments."

Natural Gas Midstream Segment

We own and operate 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. Our natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. We also own 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. We acquired our first natural gas midstream assets through the acquisition of Cantera in March 2005.

In 2007, system throughput volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 67.8 Bcf, or approximately 186 MMcfd. In 2007, three of our natural gas midstream customers accounted for 53% of our natural gas midstream revenues and 42% of our total consolidated revenues.

Revenues, profitability and the future rate of growth of our 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.

We continually seek new supplies of natural gas to both offset the natural declines in production from the wells currently connected to our systems and to increase system throughput volumes. New natural gas supplies are obtained for all of our systems by contracting for production from new wells, connecting new wells drilled on dedicated acreage and contracting for natural gas that has been released from competitors' systems. During 2007, we expended $38.7 million on expansion projects to allow us to capitalize on such opportunities. The expansion projects include two natural gas processing facilities with a combined 140 MMcfd of inlet gas capacity.

Acquisitions and Investments

Set forth below are brief descriptions of the significant acquisitions that we have made in the years ended December 31, 2007, 2006 and 2005.

Coal and Natural Resource Management Segment

In October 2007, we purchased from Penn Virginia 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 our revolving credit facility.

In September 2007, we 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 our revolving credit facility.

In June 2007, we 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 our revolving credit facility.

In May 2006, we 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 our revolving credit facility.

In July 2005, we 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 our revolving credit facility.

Natural Gas Midstream Segment

We are 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 in service by April 2008. The processing plant will provide fee-based gas processing services to Penn Virginia's 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 our revolving credit facility.

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

In March 2005, we completed our 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 our revolving credit facility. We 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 our revolving credit facility. See Note 3 in the Notes to Consolidated Financial Statements for pro forma financial information.

Liquidity and Capital Resources

We generally satisfy our working capital requirements and fund our capital expenditures and debt service obligations from cash generated from our operations and borrowings under our revolving credit facility. We believe that the cash generated from our operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distribution payments. See Note 10 in the Notes to Consolidated Financial Statements for a tabular presentation of distribution thresholds. Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance, which will be affected by, among other things, prevailing economic conditions in the coal industry and natural gas midstream market, some of which are beyond our control.

Cash Flows

The following table summarizes our cash flow statements for 2007 and 2006, consolidating our segments:

For the Year Ended December 31, 2007	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
		(in thousands)	
Cash flows from operating activities:			
Net income contribution	$ 51,681	$ 4,942	$ 56,623
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	22,238	51,206	73,444
Net change in operating assets and liabilities	3,964	(6,207)	(2,243)
Net cash provided by operating activities	$ 77,883	$ 49,941	127,824
Net cash used in investing activities	$ (177,101)	$ (47,081)	(224,182)
Net cash provided by financing activities			104,448
Net increase in cash and cash equivalents			$ 8,090

For the Year Ended December 31, 2006	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
		(in thousands)	
Cash flows from operating activities:			
Net income contribution	$ 55,015	$ 18,913	$ 73,928
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	22,478	10,878	33,356
Net change in operating assets and liabilities	1,450	(1,390)	60
Net cash provided by operating activities	$ 78,943	$ 28,401	107,344
Net cash used in investing activities	$ (92,692)	$ (36,984)	(129,676)
Net cash provided by financing activities			10,579
Net decrease in cash and cash equivalents			$ (11,753)

Cash provided by operating activities 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 our natural gas midstream segment's operating income, partially offset by increased cash outflows for derivative settlements. Cash provided by operating activities 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 our natural gas midstream business, which was acquired in March 2005, partially offset by increased cash outflows for derivative settlements.

Capital Expenditures

In 2007, we 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, we 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, we made aggregate capital expenditures of $304.9 million primarily for the acquisition of our natural gas midstream business and coal reserve acquisitions. Other investments in 2005 included a $4.1 million purchase of railcars that we previously leased and $4.4 million of natural gas gathering system additions. Capital expenditures comprise the primary portion of cash used in investing activities. The following table sets forth capital expenditures by segment made during the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Coal and natural resource management			
Acquisitions (1)	$ 176,918	$ 75,182	$ 92,093
Expansion capital expenditures	85	15,103	5,657
Other property and equipment expenditures	84	100	351
Total	177,087	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
Total capital expenditures	$ 225,540	$ 129,819	$ 304,912

(1) 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 also includes $31 million of royalty interests that we purchased from Penn Virginia. 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.

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

Distributions to partners increased to $89.6 million in 2007 from $67.0 million in 2006 and $51.9 million in 2005 because we increased the quarterly distribution per unit.

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

Long-Term Debt

As of December 31, 2007, we had outstanding borrowings of $411.7 million, consisting of $347.7 million borrowed under our revolving credit facility and $64.0 million of senior unsecured notes, or the Notes. The current portion of the Notes as of December 31, 2007 was $12.6 million.

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

The financial covenants under the Revolver require us not to exceed specified debt-to-consolidated EBITDA and consolidated EBITDA-to-interest expense ratios. The Revolver prohibits us from making distributions to our partners if any potential default, or event of default, as defined in the Revolver, occurs or would result from the distributions. In addition, the Revolver contains various covenants that limit, among other things, our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2007, we were in compliance with all of our covenants under the Revolver.

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

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 March 2010, the notional amounts of the Revolver Swaps total $160 million. From March 2010 to December 2011, the notional amounts of the Revolver Swaps total $100 million. Until March 2010, we 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, we 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 Revolver Swaps are recorded as interest expense. The Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings in interest expense. After considering the applicable margin of 1.25% in effect as of December 31, 2007, the total interest rate on the $160 million portion of Revolver borrowings covered by the Revolver Swaps was 5.58% at December 31, 2007.

Future Capital Needs and Commitments

Part of our strategy is to make acquisitions and other capital expenditures which increase cash available for distribution to our unitholders. Our ability to make these acquisitions in the future will depend in part on the availability of debt financing and on our ability to periodically use equity financing through the issuance of new common units, which will depend on various factors, including prevailing market conditions, interest rates and our financial condition and credit rating at the time. In 2008, we anticipate 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. We intend to fund these capital expenditures with a combination of cash flows provided by operating activities and borrowings under the Revolver. We make quarterly cash distributions of our available cash, generally defined as all of our cash and cash equivalents on hand at the end of each quarter less cash reserves. We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Short-term cash requirements, such as operating expenses and quarterly distributions to our general partner and unitholders, are expected to be funded through operating cash flows. 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	$347,700	$—	$—	$347,700	$—
Senior unsecured notes	64,400	12,700	27,500	19,900	4,300
Asset retirement obligation	2,028	—	—	—	2,028
Interest expense	77,901	24,913	47,384	5,475	129
Derivatives	43,048	41,733	1,315	—	—
Natural gas midstream activities (1)	40,307	11,838	10,913	10,202	7,354
Rental commitments (2)	7,902	1,810	3,395	2,697	—
Total contractual obligations (3)	$583,286	$92,994	$90,507	$385,974	$13,811

(1) Commitments for natural gas midstream activities relate to firm transportation agreements.
(2) Our rental commitments primarily relate to equipment and building leases and leases of coal reserve-based properties which we sublease, or intend to sublease, to third parties. The obligation with respect to leased properties which we sublease 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, we believe that we will incur $0.9 million in rental commitments annually until the reserves have been exhausted.
(3) Total contractual obligations do not include reimbursements to Penn Virginia. Penn Virginia is entitled to receive reimbursements of direct and indirect expenses incurred on our behalf until we are dissolved.

We do not have employment agreements with executive officers and do not have any other employees. Our compensation obligations with respect to our executive officers can be significantly different from one year to another and are based on variables such as our performance for the given year. For more a more detailed discussion on our executive compensation, see Item 11, "Executive Compensation."

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 unit data)		
Revenues	$ 549,445	$ 517,891	$ 446,348
Expenses	$ 431,720	$ 415,071	$ 368,258
Operating income	$ 117,725	$ 102,820	$ 78,090
Net income	$ 56,623	$ 73,928	$ 51,161
Net income per limited partner unit, basic and diluted	$ 0.96	$ 1.56	$ 1.22
Cash flows provided by operating activities	$ 127,824	$ 107,344	$ 93,712

Operating income increased in 2007 compared to 2006 primarily due to a $21.8 million increase in natural gas midstream gross processing margin, a $1.4 million increase in coal services revenues and a $0.9 million increase in oil and gas royalties, partially offset by a $4.1 million decrease in coal royalties revenues, a $4.0 million increase in depreciation, depletion and amortization, or DD&A, expenses and a $2.3 million increase in general and administrative expenses. Operating income increased in 2006 compared to 2005 primarily due to a $23.4 million increase in natural gas midstream gross processing margin and a $15.4 million increase in coal royalties revenues, partially offset by a $6.9 million increase in DD&A expenses, a $4.9 million increase in operating expenses and a $4.4 million increase in general and administrative expenses.

Net income decreased in 2007 compared to 2006 primarily due to a $34.3 million increase in derivative losses, partially offset by the $14.9 million increase in operating income and a $1.5 million decrease in interest expense. Net income increased in 2006 compared to 2005 primarily due to the $24.7 million increase in operating income and a $2.8 million decrease in derivative losses, partially offset by a $4.8 million increase in interest expense.

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 our 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%)
Coal services	7,252	5,864	24%
Timber	1,711	1,024	67%
Oil and gas royalty	1,864	957	95%
Other	6,672	6,973	(4%)
Total revenues	111,639	112,981	(1%)
Expenses			
Coal royalties	5,540	6,927	(20%)
Other operating	2,531	1,673	51%
Taxes other than income	1,110	934	19%
General and administrative	10,957	9,604	14%
Depreciation, depletion and amortization	22,690	20,399	11%
Total expenses	42,828	39,537	8%
Operating income	$ 68,811	$ 73,444	(6%)
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 our 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, our 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	2006	Coal Royalties Revenues Year Ended December 31, 2007	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 our 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 our 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 we sublease 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 our 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 $2.3 million, or 11%, from $20.4 million in 2006 to $22.7 million in 2007 primarily due to increased depletion resulting from our forestland acquisition in September 2007 and our oil and gas royalty interest acquisition in October 2007. In addition, we began depreciating our 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 our coal and natural resource management segment and the percentage change for the years ended December 31, 2006 and 2005:

	Year Ended December 31, 2006	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 our lessees increased by 2.6 million tons, or 8%, from 30.2 million tons in 2005 to 32.8 million tons in 2006, and our average royalty per ton increased $0.25, or 9%, from $2.74 in 2005 to $2.99 in 2006. Coal production by our lessees increased primarily due to the addition of production from the Illinois Basin reserves we acquired in July 2005 and increased production on our Central Appalachian property due to additional property we 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 our coal handling joint venture and increased revenues from coal handling facilities that processed higher volumes. Our facility on our 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 we purchased in June 2005 and a $0.6 million increase in wheelage fees primarily as a result of our April 2005 coal reserve acquisition, partially offset the $1.5 million we 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 our 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 our 2005 and 2006 acquisitions, increased professional fees and payroll costs relating to evaluating acquisition opportunities and increased reimbursement to our general partner for shared corporate overhead costs. 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.

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 our natural gas midstream segment and the percentage change for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		% Change
	2007	2006	
	(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. Our gross processing margin is the difference between our natural gas midstream revenues and our 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 our 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. Our 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 our success in contracting and connecting new supply to our facilities. Much of this new gas was a result of continued successful development by the producers operating in the vicinity of our systems. Additionally, the pipeline we acquired in 2006 allowed us to connect a number of our gathering systems directly to our 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 our 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 our gas processing plants and gathering systems increased by 16 MMcfd, or 9%, from 170 MMcfd in 2006 to 186 MMcfd in 2007.

During 2007, we generated a majority of our gross processing margin from contractual arrangements under which our margin is exposed to increases and decreases in the price of natural gas and NGLs. See Item 1, "Business—Contracts—Natural Gas Midstream Segment," for a discussion of the types of contracts utilized by our natural gas midstream segment. As part of our risk management strategy, we use 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 our 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 Penn Virginia's 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 we 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

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

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

	Year Ended December 31, 2006	Year Ended December 31, 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 our 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 our natural gas midstream business. One of the primary reasons for the significant differences in our results of operations for 2006 as compared to 2005 is that the 2006 data includes 12 full months of operations of our 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 included a $4.6 million non-cash charge to reserves for amounts related to balances assumed as part of the acquisition of Cantera. Our 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 our gas processing plants and gathering systems increased by 27 MMcfd, or 19%, from 143 MMcfd in 2005 to 170 MMcfd in 2006.

During 2006, we generated a majority of our gross processing margin from contractual arrangements under which our margin is exposed to increases and decreases in the price of natural gas and NGLs. See Item 1, "Business—Contracts—Natural Gas Midstream Segment," for a discussion of the types of contracts utilized by our natural gas midstream segment. As part of our risk management strategy, we use 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 our 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 our 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 our 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.

Other

Our other results consist of interest expense and derivative gains and losses.

Interest Expense. Interest expense decreased by $1.5 million, or 8%, from $18.8 million in 2006 to $17.3 million in 2007 primarily due to our making a $114.6 million principal payment on the Revolver in December 2006. Interest expense increased by $4.7 million, or 33%, from $14.1 million in 2005 to $18.8 million in 2006 primarily due to interest incurred on additional borrowings under the Revolver to finance the acquisition of Cantera, the June 2006 pipeline acquisition and coal property acquisitions in 2005 and 2006 and a general increase in interest rates. We capitalized interest costs amounting to $0.8 million in 2007 related to the construction natural gas processing plants. We capitalized interest costs amounting to $0.3 million in 2006 related to the construction of a coal services facility in October 2006. We had no capitalized interest in 2005.

Derivatives. Derivative losses increased by $34.3 million, or 304%, from $11.3 million in 2006 to $45.6 million in 2007. The derivative losses in 2007 consisted of a $27.8 million unrealized loss for mark-to-market adjustments and a $17.8 realized loss. Derivative losses decreased by $2.7 million, or 19%, from $14.0 million in 2005 to $11.3 million in 2006. The derivative losses in 2006 consisted of a $11.2 unrealized loss for mark-to-market adjustments and a $0.1 million realized loss.

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.

Natural Gas Midstream Revenues

We recognize revenues from the sale of NGLs and residue gas when we sell the NGLs and residue gas produced at our 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 our lessees and the corresponding revenues from those sales. Since we do not operate any coal mines, we do not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. 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 historically have entered into derivative financial instruments that would qualify for hedge accounting under Statement of Financial Accounting Standards, or 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 our natural gas derivatives and a large portion of our 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 (partners' capital). 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 fluctuations 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. We will recognize hedging losses of $5.5 million in 2008 related to such settlements. 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.

Depletion

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 our own geologists and coal reserve engineers. Our 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. We determine depletion of oil and gas royalty interests by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves.

Goodwill

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 tested for impairment at least annually. Accordingly, we do not amortize goodwill. We test goodwill for impairment during the fourth quarter of each fiscal year. Based on the results of our test during the fourth quarter of 2007, no goodwill impairment was recognized in 2007.

Intangible Assets

Intangible assets are primarily associated with assumed contracts, customer relationships and rights-of-way. These intangible assets are amortized over periods of up to 15 years, the period in which benefits are derived from the 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*.

Environmental Matters

Our operations and those of our 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 our coal property leases impose liability for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. The lessees are bonded and have indemnified us against any and all future environmental liabilities. We regularly visit our coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Our management believes that our operations and those of our lessees comply with existing laws and regulations and does not expect any material impact on our financial condition or results of operations.

As of December 31, 2007 and 2006, our environmental liabilities included $1.5 million and $1.6 million, which represents our best estimate of the liabilities as of those dates related to our coal and natural resource management and natural gas midstream businesses. We have reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future. For a summary of the environmental laws and regulations applicable to our operations, see Item 1, "Business—Government Regulation and Environmental Matters."

Recent Accounting Pronouncements

See Note 2 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 of 1933 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 customers and lessees. If our 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 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 $45.6 million. Because during the first quarter of 2006 our natural gas derivatives and a large portion of our 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 (partners' capital). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through

2008 as the original hedged transactions settle. We will recognize hedging losses of $5.5 million in 2008 related to such settlements. 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 7 in the Notes to Consolidated Financial Statements for a description of our derivatives program.

The following table lists our 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 $347.7 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 $160 million of the amount outstanding under the 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 Revolver Swaps will effectively convert the interest rate on $100 million of the amount outstanding under the 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 Revolver (net of amounts fixed through hedging transactions) at December 31, 2007 would cost us approximately $1.9 million in additional interest expense.

Item 8 Financial Statements and Supplementary Data

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
Penn Virginia Resource Partners, L.P.:

We have audited the accompanying consolidated balance sheets of Penn Virginia Resource Partners, L.P., a Delaware limited partnership, and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of income, partners' capital 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 Partnership'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 Resource Partners, L.P. 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Penn Virginia Resource Partners, L.P.'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 Partnership's internal control over financial reporting.

KPMG LLP

Houston, Texas
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
Penn Virginia Resource Partners, L.P.:

We have audited Penn Virginia Resource Partners, L.P.'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 Resource Partners, L.P.'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 Partnership'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 Resource Partners, L.P. 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 Resource Partners, L.P. as of December 31, 2007 and 2006, and the related consolidated statements of income, partners' capital 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 RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per unit amounts)

	Year Ended December 31,		
	2007	2006	2005
Revenues			
Natural gas midstream	$ 433,174	$ 402,715	$ 348,657
Coal royalties	94,140	98,163	82,725
Coal services	7,252	5,864	5,230
Other	14,879	11,149	9,736
Total revenues	549,445	517,891	446,348
Expenses			
Cost of midstream gas purchased	343,293	334,594	303,912
Operating	20,964	20,003	15,102
Taxes other than income	3,036	2,354	2,397
General and administrative	22,915	20,627	16,219
Depreciation, depletion and amortization	41,512	37,493	30,628
Total expenses	431,720	415,071	368,258
Operating income	117,725	102,820	78,090
Other income (expense)			
Interest expense	(17,338)	(18,821)	(14,054)
Interest income	1,804	1,189	1,149
Derivatives	(45,568)	(11,260)	(14,024)
Net income	$ 56,623	$ 73,928	$ 51,161
General partner's interest in net income	$ 12,452	$ 8,321	$ 2,122
Limited partners' interest in net income	$ 44,171	$ 65,607	$ 49,039
Basic and diluted net income per limited partner unit (see Note 2)	$ 0.96	$ 1.56	$ 1.22
Weighted average number of units outstanding, basic and diluted:			
Common	44,550	35,639	29,464
Subordinated	-	6,375	10,838
Class B	1,553	-	-

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands, except unit amounts)

	As of December 31,	
	2007	2006
Assets		
Current assets		
Cash and cash equivalents	$ 19,530	$ 11,440
Accounts receivable	78,888	66,987
Derivative assets	1,212	449
Other current assets	4,104	2,587
Total current assets	103,734	81,463
Property, plant and equipment	877,571	665,135
Accumulated depreciation, depletion and amortization	(146,289)	(108,622)
Net property, plant and equipment	731,282	556,513
Equity investments	25,640	25,355
Goodwill	7,718	7,718
Intangibles, net	28,938	33,045
Derivative assets	-	2,455
Other long-term assets	33,967	7,474
Total assets	$ 931,279	$ 714,023
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	$ 65,483	$ 52,006
Accrued liabilities	10,753	11,247
Current portion of long-term debt	12,561	10,832
Deferred income	2,958	6,999
Derivative liabilities	41,733	6,996
Total current liabilities	133,488	88,080
Deferred income	6,889	6,592
Other liabilities	19,158	3,339
Derivative liabilities	1,315	6,618
Long-term debt	399,153	207,214
Commitments and contingencies (Note 13)		
Partners' capital		
Common units (46,106,285 at December 31, 2007 and 42,060,974 at December 31, 2006)	373,915	302,938
Class B units (zero at December 31, 2007 and 4,012,164 at December 31, 2006)	-	102,500
General partner interest	4,753	5,394
Accumulated other comprehensive loss	(7,392)	(8,652)
Total partners' capital	371,276	402,180
Total liabilities and partners' capital	$ 931,279	$ 714,023

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2007	2006	2005
Cash flows from operating activities			
Net income	$ 56,623	$ 73,928	$ 51,161
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	41,512	37,493	30,628
Commodity derivative contracts:			
Total derivative losses	50,163	13,213	13,036
Cash settlements on derivatives	(17,779)	(19,436)	(4,752)
Non-cash interest expense	678	769	1,735
Equity earnings, net of distributions received	(285)	1,317	1,269
Other	(845)	-	-
Changes in operating assets and liabilities:			
Accounts receivable	(12,701)	9,411	(27,318)
Accounts payable	13,435	(5,847)	18,090
Accrued liabilities	(1,415)	(958)	6,490
Deferred income	(1,799)	(1,676)	2,063
Other assets and liabilities	237	(870)	1,310
Net cash provided by operating activities	127,824	107,344	93,712
Cash flows from investing activities			
Acquisitions, net of cash acquired	(176,917)	(91,259)	(290,938)
Additions to property, plant and equipment	(48,123)	(38,453)	(12,735)
Other	858	36	52
Net cash used in investing activities	(224,182)	(129,676)	(303,621)
Cash flows from financing activities			
Distributions to partners	(89,649)	(66,954)	(51,949)
Proceeds from borrowings	220,500	85,800	288,800
Repayments of borrowings	(27,000)	(122,900)	(151,600)
Proceeds from issuance of units	860	115,008	129,239
Payments for debt issuance costs	(263)	(375)	(2,385)
Net cash provided by financing activities	104,448	10,579	212,105
Net increase (decrease) in cash and cash equivalents	8,090	(11,753)	2,196
Cash and cash equivalents – beginning of period	11,440	23,193	20,997
Cash and cash equivalents – end of period	$ 19,530	$ 11,440	$ 23,193
Supplemental disclosure:			
Cash paid for interest	$ 15,880	$ 18,312	$ 12,138
Noncash investing and financing activities:			
Issuance of units for acquisitions	$ -	$ -	$ 10,415
Assumption of liabilities in acquisitions	$ -	$ -	$ 3,981

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL AND COMPREHENSIVE INCOME
(in thousands)

	Common Units		Class B Units		Subordinated Units		General Partner	Accumulated Other Comprehensive Income (Loss)	Total	Comprehensive Income (Loss)
	Units	Amount	Units	Amount	Units	Amount				
Balance at December, 31, 2004	24,674	$ 164,738	-	$ -	11,474	$ (15,032)	$ 278	$ -	$ 149,984	$ 34,315
Capital contributions	-	-	-	-	-	-	2,783	-	2,783	
Issuance of units	5,496	136,871	-	-	-	-	-	-	136,871	
Conversion of subordinated units	3,824	(5,538)	-	-	(3,824)	5,538	-	-	-	
Distributions ($1.24 per unit)	-	(35,775)	-	-	-	(14,243)	(1,931)	-	(51,949)	
Net income allocation	-	35,742	-	-	-	13,297	2,122	-	51,161	$ 51,161
Other comprehensive loss	-	-	-	-	-	-	-	(4,891)	(4,891)	(4,891)
Balance at December 31, 2005	33,994	296,038	-	-	7,650	(10,440)	3,252	(4,891)	283,959	$ 46,270
Capital contributions	-	-	-	-	-	-	2,298	-	2,298	
Issuance of units	416	10,601	4,012	102,109	-	-	-	-	112,710	
Conversion of subordinated units	7,650	(10,658)	-	-	(7,650)	10,658	-	-	-	
Distributions ($1.475 per unit)	-	(50,142)	-	-	-	(11,284)	(5,528)	-	(66,954)	
Net income allocation	-	57,099	-	391	-	11,066	5,372	-	73,928	$ 73,928
Other comprehensive loss	-	-	-	-	-	-	-	(3,761)	(3,761)	(3,761)
Balance at December 31, 2006	42,060	302,938	4,012	102,500	-	-	5,394	(8,652)	402,180	$ 70,167
Capital contributions	-	-	-	-	-	-	19	-	19	
Issuance of units	-	-	34	843	-	-	-	-	843	
Conversion of class B units	4,046	99,675	(4,046)	(99,675)	-	-	-	-	-	
Distributions ($1.66 per unit)	-	(73,260)	-	(3,277)	-	-	(13,112)	-	(89,649)	
Net income allocation	-	44,562	-	(391)	-	-	12,452	-	$ 56,623	$ 56,623
Other comprehensive income	-	-	-	-	-	-	-	1,260	1,260	1,260
Balance at December 31, 2007	46,106	$ 373,915	-	$ -	-	$ -	$ 4,753	$ (7,392)	$ 371,276	$ 57,883

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

Penn Virginia Resource Partners, L.P. (the "Partnership," "we," "us" or "our") is a publicly traded Delaware limited partnership formed by Penn Virginia Corporation ("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. We currently conduct operations in two business segments: (1) coal and natural resource management and (2) natural gas midstream.

Our coal and natural resource management segment primarily involves the management and leasing of coal and natural resource properties and the subsequent collection of royalties. We also earn revenues from the provision of fee-based coal preparation and loading services, from the sale of standing timber on our properties, from oil and gas royalty interests we own and from coal transportation, or wheelage, fees.

Our natural gas midstream segment is engaged in providing gas processing, gathering and other related natural gas services. We own and operate natural gas midstream assets located in Oklahoma and the panhandle of Texas. Our natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. We also own 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.

Our general partner is Penn Virginia Resource GP, LLC, which is a wholly-owned subsidiary of Penn Virginia GP Holdings, L.P. ("PVG"). Penn Virginia owns an approximately 82% limited partner interest in PVG, as well as the non-economic general partner interest in PVG. PVG owns an approximately 42% limited partner interest in us as well as the 2% general partner interest in us.

2. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of the Partnership and all of its wholly-owned subsidiaries. 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 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.

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.

Property, Plant and Equipment

Property, plant and equipment consist of our ownership in coal fee mineral interests, our royalty interest in oil and natural gas wells, forestlands, processing facilities, gathering systems, compressor stations and related equipment. Property, plant 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, plant and equipment using the straight-line 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, we carry out core-hole drilling activities on our 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 facility type information. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. See Note 8, "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 our 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.

Equity Investments

We use the equity method of accounting to account for our investment in a coal handling joint venture, recording our initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect our share of income of the investee and is reduced to reflect our share of losses of the investee or distributions received from the investee as the joint venture reports them. Our share of earnings or losses from the investment is included in coal services revenues on our consolidated statements of income. Coal services revenues also includes amortization of the amount of our equity investment that exceeds our portion of the underlying equity in net assets. We record amortization over the life of coal services contracts in place at the time of our 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 3). The goodwill has been allocated to our 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 3). 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

Debt Issuance Costs

Debt issuance costs relating to long-term debt have been capitalized and are being amortized over the term of the related debt instrument.

Long-Term Prepaid Minimums

We lease a portion of our reserves from third parties which require monthly or annual minimum rental payments. The prepaid minimums are recoupable from future production and are deferred and charged to coal royalties expense as the coal is subsequently produced. We evaluate the recoverability of the prepaid minimums on a periodic basis; consequently, any prepaid minimums that cannot be recouped are charged to coal royalties expense.

Environmental Liabilities

Other liabilities include accruals for environmental liabilities that we either assumed in connection with certain acquisitions or recorded in operating expenses when it became probable that a liability had been incurred and the amount of that liability could be reasonably estimated.

Concentration of Credit Risk

Approximately 88% of our consolidated accounts receivable at December 31, 2007 resulted from our natural gas midstream segment and approximately 12% resulted from our coal and natural resource management segment. Approximately 24% of our consolidated accounts receivable at December 31, 2007 related to one natural gas midstream 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 lessee or customer, 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 $65.8 million and $75.4 million.

Revenues

Natural Gas Midstream Revenues. We recognize revenues from the sale of natural gas liquids ("NGLs") and residue gas when we sell the NGLs and residue gas produced at our 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 our lessees and the corresponding revenues from those sales. Since we do not operate any coal mines, we do not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. 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 our lessees must make minimum monthly or annual payments that are generally recoupable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recoups a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal 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 revenues 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.

Coal Services Revenues. We recognize coal services revenues when lessees use our facilities for the processing, loading and/or transportation of coal. Coal services revenues consist of fees collected from lessees for the use of our loadout facility, coal preparation plants and dock loading facility. We also include equity earnings in coal services revenues. We recognize our share of income or losses from our investment in a coal handling joint venture as the joint venture reports them to us.

Timber Revenues. We recognize timber revenues based on the volume of timber harvested and sold from our properties.

Derivative Activities

From time to time, we enter into derivative financial instruments to mitigate our exposure to NGL, crude oil and natural gas 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 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 the board of directors of our general partner.

We 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 our natural gas derivatives and a large portion of our 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 (partners' capital).

The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. See Note 7, "Derivative Instruments." 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.

Income Taxes

As a partnership, we are not a taxable entity and have no federal income tax liability. The taxable income and losses of the Partnership are includable in the federal and state income tax returns of our partners. Net income for financial statement purposes may differ significantly from taxable income reportable to partners as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under our partnership agreement.

Net Income per Limited Partner Unit

Emerging Issues Task Force ("EITF") Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*, addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. EITF Issue No. 03-6 provides that in any accounting period where our net income exceeds our distribution for such period, we are required to present net income per limited partner unit as if all of the net income for the period was distributed, regardless of the pro forma nature of this allocation and whether that net income would actually be distributed during a particular period from an economic or practical perspective. In this instance, basic and diluted net income per limited partner unit is determined by dividing net income available to limited partners by the weighted average number of limited partner units outstanding during the period. To calculate net income available to limited partners, income is first allocated to our general partner based on the amount of incentive distributions to which it is entitled and the remainder is allocated between the limited partners and our general partner based on their percentage ownership interests in us.

We make cash distributions on the basis of cash available for distributions, not net income, in any given accounting period. In accounting periods where our net income does not exceed our distributions for such period, EITF Issue No.03-6 does not apply and basic and diluted net income per limited partner unit is determined by dividing net income by the weighted average number of limited partner units outstanding during the period.

The following table reconciles net income and weighted average units used in computing basic and diluted net income per limited partner unit:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands, except unit data)		
Net income	$ 56,623	$ 73,928	$ 51,161
Less: General partner's incentive distributions paid	(11,551)	(4,273)	(910)
Subtotal	45,072	69,655	50,251
General partner's interest in net income	(901)	(1,099)	(1,212)
Limited partners' interest in net income	44,171	68,556	49,039
Additional earnings allocation to general partner under EITF 03-6	-	(2,949)	-
Net income available to limited partners under EITF 03-6	$ 44,171	$ 65,607	$ 49,039
Weighted average limited partner units, basic and diluted	46,103	42,014	40,302
Basic and diluted net income per limited partner unit	$ 0.96	$ 1.56	$ 1.22

Unit-Based Compensation

Our general partner has a long-term incentive plan that permits the grant of awards to directors and employees of our general partner and employees of its affiliates who perform services for us. Awards under our long-term incentive plan can be in the form of common units, restricted units, unit options, phantom units and deferred common units. Our long-term incentive plan is administered by the compensation and benefits committee of our general partner's board of directors. We reimburse our general partner for payments made pursuant to our long-term incentive plan and recognize compensation expense over the vesting period of the awards.

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 effective 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.

3. Acquisitions

In the following paragraphs, all references to coal, crude 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, we completed our acquisition (the "Cantera Acquisition") of Cantera Gas Resources, LLC ("Cantera"), 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 we funded with a $110 million term loan and with long-term debt under our revolving credit facility.

We used proceeds of $126.4 million from our sale of common units in a subsequent public offering in March 2005 and a $2.6 million contribution from our general partner to repay the term loan in full and to reduce outstanding indebtedness under our 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 our entry into the natural gas midstream business and our 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, interest expense for acquisition debt and the change in weighted average common units resulting from the public offering. 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 unit data)
Revenues	$518,790
Net income	$51,519
Net income per limited partner unit, basic and diluted	$1.22

In September 2007, we 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 our 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. We are awaiting final appraisals of an assumed contract and additional analysis on the fair value of the land and timber.

In June 2007, we 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 our 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.

The pro forma results for the years ended December 31, 2006 and 2005 for the northern West Virginia timber and western Kentucky coal acquisitions do not materially change the net income for these periods.

Other Acquisitions

In October 2007, we purchased from Penn Virginia oil and gas royalty interests associated with leases of property in eastern Kentucky and southwestern Virginia and with estimated proved reserves of 8.7 billion cubic feet of natural gas equivalent at January 1, 2007. The purchase price was $31.0 million in cash and was funded with long-term debt under our revolving credit facility.

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

In May 2006, we 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 our revolving credit facility.

In July 2005, we 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 our revolving credit facility.

4. Property and Equipment

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

	As of December 31,	
	2007	2006
	(in thousands)	
Coal properties	$ 453,484	$ 414,935
Compressor stations	49,693	49,071
Gathering systems	159,652	121,467
Coal services equipment	38,840	38,755
Processing plants	28,695	19,273
Land	17,753	11,291
Oil and gas royalties	36,395	5,395
Timber	87,800	399
Other property and equipment	5,259	4,549
	877,571	665,135
Accumulated depreciation, depletion and amortization	(146,289)	(108,622)
Net property and equipment	$ 731,282	$ 556,513

5. Equity Investments

In 2004, we acquired a 50% interest in Coal Handling Solutions, LLC, a joint venture formed to own and operate end-user coal handling facilities. We account for the investment under the equity method of accounting. At December 31, 2007 and 2006, our equity investment totaled $25.6 million and $25.4 million, which exceeded our portion of the underlying equity in net assets by $7.7 million and $8.7 million. The difference is being amortized to equity earnings over the life of coal services contracts in place at the time of the acquisition. In accordance with the equity method, we recognized equity earnings of $1.8 million in 2007, $1.3 million in 2006 and $1.1 million in 2005, with a corresponding increase in the investment. The joint venture generally pays to us quarterly distributions of our portion of the joint venture's cash flows. We received cash distributions from the joint venture of $1.5 million in 2007, $2.7 million in 2006 and $2.3 million in 2005.

Equity earnings are included in coal services revenues on our consolidated statements of income, and the equity investment is included in other long-term assets on our consolidated balance sheets.

6. Allowance for Prepaid Minimums

We establish provisions for losses on long-term prepaid minimums if we determine that we will not recoup all or part of the outstanding balance. Collectibility is reviewed periodically and an allowance is established or adjusted, as necessary, using the specific identification method. The allowance is netted against long-term prepaid minimums on our consolidated balance sheets. The following table presents the activity of our allowance for prepaid minimums for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Balance at beginning of period	$1,737	$1,692	$1,514
Charges to expense	(91)	60	178
Forfeiture of prepaid minimum	—	(15)	—
Balance at end of period	$1,646	$1,737	$1,692

7. Derivative Instruments

Natural Gas Midstream Segment Commodity Derivatives

We utilize 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. We also utilize swap derivative contracts to hedge against the variability in our "frac spread." Our frac spread is the spread between the purchase price for the natural gas we purchase from producers and the sale price for the NGLs that we sell after processing. We hedge against the variability in our 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. 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.

The fair values of our derivative agreements are determined based on forward price quotes for the respective commodities as of December 31, 2007. The following table sets forth our 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	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)**

At December 31, 2007, we 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 $5.5 million related to derivatives in the natural gas midstream segment for which we discontinued hedge accounting in 2006. The $5.5 million loss will be recorded in earnings through the end of 2008 as the hedged transactions settle. 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 midstream revenues	$ (8,515)	$(10,331)	$ (3,871)
Cost of midstream gas purchased	3,920	8,378	4,859
Derivatives	(45,568)	(11,260)	(14,024)
Increase (decrease) in net income	$(50,163)	$(13,213)	$(13,036)
Realized and unrealized derivative impact:			
Cash paid for derivative settlements	$(17,779)	$(19,436)	$ (4,752)
Unrealized derivative gain (loss)	(32,384)	6,223	(8,284)
Increase (decrease) in net income	$(50,163)	$(13,213)	$(13,036)

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 March 2010, the notional amounts of the Revolver Swaps total $160 million. From March 2010 to December 2011, the notional amounts of the Revolver Swaps total $100 million. Until March 2010, we 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 London Inter Bank Offering Rate (the "LIBOR"). From March 2010 to December 2011, we 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 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 $1.9 million at December 31, 2007 and (ii) a loss in accumulated other comprehensive income of $1.9 million at December 31, 2007 related to the Revolver Swaps. In connection with periodic settlements, we recognized $0.7 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 $0.6 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.

8. 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	$1,881	$1,458
Liabilities incurred	—	301
Accretion expense	147	122
Balance at end of period	$2,028	$1,881

9. 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 6.2% at December 31, 2007	$347,700	$143,200
Senior unsecured notes	64,014	74,846
Total debt	411,714	218,046
Less: Current maturities	(12,561)	(10,832)
Total long-term debt	$399,153	$207,214

We capitalized interest costs amounting to $0.8 million in 2007 related to the construction of natural gas processing plants. We capitalized interest costs amounting to $0.3 million in 2006 related to the construction of a coal services facility in October 2006. We did not capitalize any interest in 2005.

Revolving Credit Facility

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

The financial covenants under the Revolver require us not to exceed specified debt-to-consolidated EBITDA and consolidated EBITDA-to-interest expense ratios. The Revolver prohibits us from making distributions to our partners if any potential default, or event of default, as defined in the Revolver, occurs or would result from the distributions. In addition, the Revolver contains various covenants that limit, among other things, our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2007, we were in compliance with all of our covenants under the Revolver.

Senior Unsecured Notes

As of December 31, 2007, we owed $64.0 million under our senior unsecured notes (the "Notes"). The Notes bear interest at a fixed rate of 6.02% and mature in March 2013, with semi-annual principal and interest payments. The Notes are equal in right of payment with all of our other unsecured indebtedness, including the Revolver. The Notes require us to obtain an annual confirmation of our credit rating, with a 1.00% increase in the interest rate payable on the Notes in the event that our credit rating falls below investment grade. In March 2007, our investment grade credit rating was confirmed by Dominion Bond Rating Services. The Notes contain various covenants similar to those contained in the Revolver. As of December 31, 2007, we were in compliance with all of our covenants under the 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	13,400
2011	358,500
2012	9,100
Thereafter	4,300
Total principal	412,100
Less: Terminated interest rate swap	(386)
Total debt, including current maturities	$411,714

10. Partners' Capital and Distributions

As of December 31, 2007, partners' capital consisted of 46.1 million common units, representing a 98% limited partner interest and a 2% general partner interest. As of December 31, 2007, affiliates of Penn Virginia, in the aggregate, owned a 44% interest in us, consisting of 19.8 million common units and a 2% general partner interest.

Unit Split

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

Subordinated Units

Until November 14, 2006, we had a separate class of subordinated units representing limited partner interests in us, and the rights of holders of subordinated units to participate in distributions to limited partners were subordinated to the rights of the holders of our common units. On November 14, 2006, all of our subordinated units converted into common units on a one-for-one basis and no subordinated units remain outstanding.

Until May 22, 2007, we had Class B units, a separate class of subordinated units representing limited partner interests in us that were issued to PVG in connection with PVG's initial public offering. On May 22, 2007, all of our Class B units automatically converted into common units on a one-for-one basis and no Class B units remain outstanding.

Cash Distributions

We distribute 100% of Available Cash (as defined in our partnership agreement) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available Cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established by our general partner for future requirements. Our general partner has the discretion to establish cash reserves that are necessary or appropriate to (i) provide for the proper conduct of our business; (ii) comply with applicable law, any of our debt instruments or other agreements; or (iii) provide funds for distributions to unitholders and our general partner for any one or more of the next four quarters.

According to our partnership agreement, our general partner receives incremental incentive cash distributions if cash distributions exceed certain target thresholds as follows:

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

The following table reflects the allocation of total cash distributions paid by us during the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousand, except per unit data)		
Limited partner units	$76,536	$61,427	$50,018
General partner interest (2%)	1,562	1,254	1,021
Incentive distribution rights	11,551	4,273	910
Total cash distributions paid	$89,649	$66,954	$51,949
Total cash distributions paid per unit	$1.6660	$1.4750	$1.2413

On February 14, 2008, the board of directors of our general partner paid a $0.44 per unit quarterly distribution ($1.76 per unit on an annualized basis) to unitholders of record on February 4, 2008.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then current market price of the common units.

11. Related Party Transactions

General and Administrative

Penn Virginia charges us for certain corporate administrative expenses which are allocable to us and our subsidiaries. When allocating general corporate expenses, consideration is given to property and equipment, payroll and general corporate overhead. Any direct costs are paid by us. Total corporate administrative expenses charged to us totaled $4.2 million, $4.5 million and $2.6 million for the years ended December 31, 2007, 2006 and 2005. These costs are reflected in general and administrative expenses in our consolidated statements of income. At least annually, our management performs an analysis of general corporate expenses based on time allocations of shared employees and other pertinent factors. Based on this analysis, our management believes that the allocation methodologies used are reasonable.

Accounts Payable—Affiliate

Amounts payable to related parties totaled $2.4 million and $2.0 million as of December 31, 2007 and 2006. This balance consists primarily of amounts due to our general partner for general and administrative expenses incurred on our behalf and is included in accounts payable on our consolidated balance sheets.

Marketing Revenues

Penn Virginia Oil & Gas, L.P. ("PVOG") and Connect Energy Services, LLC ("Connect Energy"), a wholly-owned subsidiary of us, are parties to a Master Services Agreement effective September 1, 2006. Pursuant to the Master Services Agreement, PVOG and Connect Energy have agreed that Connect Energy will market all of PVOG's oil and gas production in Arkansas, Louisiana, Oklahoma and Texas for a fee equal to 1% of the net sales price (subject to specified limitations) received by PVOG for such production. The Master Services Agreement has a primary term of five years and automatically renews for additional one year terms until terminated by either party. In 2007 and 2006, PVOG paid Connect Energy $2.2 million and $0.4 million in fees pursuant to the Master Services Agreement. Marketing revenues are included in other revenues on our consolidated statements of income.

Purchase of Royalty Interests

In October 2007, we purchased from Penn Virginia Oil & Gas Corporation, a wholly-owned subsidiary of Penn Virginia, 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 our revolving credit facility.

12. Unit-Based Payments

Long-Term Incentive Plan

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

We recognize compensation expense related to the granting of common units and deferred common units and the vesting of restricted units granted under our long-term incentive plan. We recognized compensation expense related to our 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.

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

The following table summarizes the status of our nonvested restricted 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, we had $2.7 million of total unrecognized compensation cost related to nonvested restricted units. We expect to reimburse our general partner for that cost over a weighted-average period of 0.9 years. The total grant-date fair value of restricted units that vested in 2007, 2006 and 2005 was $1.2 million, $2.2 million and $0.4 million.

Deferred Common Units. A portion of the compensation to the non-employee directors of our general partner is paid in deferred common units. Each deferred common unit represents one 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. At December 31, 2006, 39,009 deferred common units were outstanding at a weighted average grant-date fair value of $25.26 per common unit. Our general partner granted 22,209 deferred common units in 2007 at a weighted average grant-date fair value of $26.43. At December 31, 2007, 61,218 deferred common units were outstanding at a weighted average grant-date fair value of $25.58. The aggregate intrinsic value of deferred common units converted to common units in 2006 was $0.2 million. No deferred common units converted to common units in 2007 or 2005.

13. Commitments and Contingencies

Rental Commitments

Operating lease rental expense in the years ended December 31, 2007, 2006 and 2005 was $2.6 million, $1.9 million and $0.9 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	$1,810
2009	1,709
2010	1,686
2011	1,479
2012	1,218
Total minimum payments	$7,902

Our rental commitments primarily relate to equipment and building leases and leases of coal reserve-based properties which we sublease, or intend to sublease, to third parties. The obligation with respect to leased properties which we sublease 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, we believe that we will incur $0.9 million in rental commitments annually until the reserves have been exhausted.

Firm Transportation Commitments

As of December 31, 2007, our firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to seven 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	$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

Our operations and those of our 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 our coal property leases impose liability for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. The lessees are bonded and have indemnified us against any and all future environmental liabilities. We regularly visit our coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Our management believes that our operations and those of our lessees comply with existing laws and regulations and does not expect any material impact on our financial condition or results of operations.

As of December 31, 2007 and 2006, our environmental liabilities included $1.5 million and $1.6 million, which represents our best estimate of the liabilities as of those dates related to our coal and natural resource management and natural gas midstream businesses. We have reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

Mine Health and Safety Laws

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

14. Comprehensive Income

Comprehensive income represents changes in partners' capital during the reporting period, including net income and charges directly to partners' capital which are excluded from net income. The following table sets forth the components of comprehensive income for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Net income	$ 56,623	$ 73,928	$ 51,161
Unrealized holding losses on derivative activities	(2,599)	(5,669)	(3,903)
Reclassification adjustment for derivative activities	3,859	1,909	(988)
Comprehensive income	$ 57,883	$ 70,168	$ 46,270

15. 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 coal and natural resource management operations and our natural gas midstream operations. Accordingly, our reportable segments are as follows:

- 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.
- 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:

	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
		(in thousands)	
For the year ended December 31, 2007			
Revenues	$ 111,639	$ 437,806	$ 549,445
Cost of midstream gas purchased	-	343,293	343,293
Operating costs and expenses	20,138	26,777	46,915
Depreciation, depletion and amortization	22,690	18,822	41,512
Operating income	$ 68,811	$ 48,914	117,725
Interest expense, net			(15,534)
Derivatives			(45,568)
Net income			$ 56,623
Total assets	$ 610,866	$ 320,413	$ 931,279
Equity investments	25,580	60	25,640
Additions to property, plant and equipment and acquisitions (1)	177,960	47,080	225,040
For the year ended December 31, 2006			
Revenues	$ 112,981	$ 404,910	$ 517,891
Cost of midstream gas purchased	-	334,594	334,594
Operating costs and expenses	19,138	23,846	42,984
Depreciation, depletion and amortization	20,399	17,094	37,493
Operating income	$ 73,444	$ 29,376	102,820
Interest expense, net			(17,632)
Derivatives			(11,260)
Net income			$ 73,928
Total assets	$ 409,709	$ 304,314	$ 714,023
Equity investments	25,295	60	25,355
Additions to property, plant and equipment and acquisitions (2)	92,697	37,015	129,712
For the year ended December 31, 2005			
Revenues	$ 95,755	$ 350,593	$ 446,348
Cost of midstream gas purchased	-	303,912	303,912
Operating costs and expenses	16,121	17,597	33,718
Depreciation, depletion and amortization	17,890	12,738	30,628
Operating income	$ 61,744	$ 16,346	78,090
Interest expense, net			(12,905)
Derivatives			(14,024)
Net income			$ 51,161
Total assets	$ 372,322	$ 285,557	$ 657,879
Equity investments	26,612	60	26,672
Additions to property, plant and equipment and acquisitions (3)	96,862	206,811	303,673

(1) Coal and natural resource management segment additions to property, plant and equipment and acquisitions 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.

(2) Coal and natural resource management segment additions to property, plant and equipment and acquisitions in 2006 includes acquisition of assets other than property or equipment of $1.2 million.

(3) Coal and natural resource management segment additions to property, plant and equipment and acquisitions in 2005 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, three customers of our natural gas midstream segment accounted for approximately $109.2 million, $61.0 million and $60.5 million, or 20%, 11% and 11%, of our total consolidated net revenues. For the year ended December 31, 2006, two customers of our natural gas midstream segment accounted for $129.1 million and $67.4 million, or 25% and 13%, of our total consolidated net revenues. For the year ended December 31, 2005, two customers of our natural gas midstream segment accounted for $81.9 million and $77.1 million, or 18% and 17%, of our total consolidated net revenues.

Quarterly Financial Information (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except unit data)			
2007				
Revenues	$ 124,200	$ 144,144	$ 130,204	$ 150,897
Operating income	$ 22,340	$ 27,382	$ 31,771	$ 36,232
Net income	$ 16,433	$ 16,560	$ 16,662	$ 6,968
Basic and diluted net income per limited partner unit, common and class B (1)	$ 0.30	$ 0.30	$ 0.29	$ 0.07
Weighted average number of units outstanding, basic and diluted:				
Common	42,061	44,084	46,106	46,106
Class B	4,045	2,023	-	-
2006				
Revenues	$ 135,164	$ 123,463	$ 131,494	$ 127,770
Operating income	$ 18,246	$ 29,289	$ 29,898	$ 25,387
Net income	$ 8,340	$ 13,221	$ 31,339	$ 21,028
Basic and diluted net income per limited partner unit, common, subordinated and class B (1)	$ 0.19	$ 0.30	$ 0.55	$ 0.41
Weighted average number of units outstanding, basic and diluted:				
Common	33,994	33,994	33,994	40,571
Subordinated & Class B	7,650	7,650	7,650	2,550

(1) The sum of the quarters may not equal the total of the respective year's net income per limited partner unit due to changes in the weighted average units outstanding throughout the year and due to applying the two-class method of calculating net income per limited partner unit (see Note 2).

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, or KPMG, 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*

Directors and Executive Officers

The following table sets forth information concerning the directors and executive officers of our general partner. All directors of our general partner are elected, and may be removed, by PVG, its sole member and a majority-owned subsidiary of Penn Virginia.

Name	Age	Position with our General Partner
A. James Dearlove	60	Chairman of the Board of Directors and Chief Executive Officer
Edward B. Cloues, II	60	Director
John P. DesBarres	68	Director
James L. Gardner	56	Director
James R. Montague	60	Director
Marsha R. Perelman	57	Director
Frank A. Pici	52	Director and Vice President and Chief Financial Officer
Nancy M. Snyder	54	Director and Vice President and General Counsel
Keith D. Horton	54	Co-President and Chief Operating Officer—Coal
Ronald K. Page	57	Co-President and Chief Operating Officer—Midstream

A. James Dearlove has served as Chairman of the Board of Directors and Chief Executive Officer of our general partner since December 2002 and July 2001 and as Chairman of the Board of Directors and Chief Executive Officer of PVG's general partner since September 2006. Mr. Dearlove has also served in various capacities with Penn Virginia since 1977, including as President and Chief Executive Officer since May 1996, as President and Chief Operating Officer from 1994 to May 1996, as Senior Vice President from 1992 to 1994 and as Vice President from 1986 to 1992. Mr. Dearlove also serves as a director of Penn Virginia and as a director of the National Council of Coal Lessors.

Edward B. Cloues, II has served as a director of our general partner since January 2003. Since January 1998, Mr. Cloues has served as Chairman of the Board and Chief Executive Officer of K-Tron International, Inc., a provider of material handling equipment and systems. From October 1979 to January 1998, Mr. Cloues was a partner of Morgan, Lewis & Bockius LLP, a law firm. Mr. Cloues also serves as a director of Penn Virginia and is the non-executive Chairman of the Board of AMREP Corporation.

John P. DesBarres has served as a director of our general partner since July 2001. Since 1996, Mr. DesBarres has been a private investor residing in Park City, Utah. From 1991 to 1995, Mr. DesBarres served as the Chairman, President and Chief Executive Officer of Transco Energy Company, an energy company which merged with The Williams Companies, Inc. in 1995. Mr. DesBarres serves as a director of American Electric Power, Inc. and as a director of the general partner of Magellan Midstream Partners, L.P.

James L. Gardner has served as a director of our general partner since January 2006. Since 2005, Mr. Gardner has been an Associate Professor of Interdisciplinary Studies at Freed-Hardeman University. From 2002 to 2004, Mr. Gardner served as Executive Vice President and Chief Administrative Officer of Massey, a coal mining company. From 2000 to 2002, Mr. Gardner was in the private practice of law, principally representing Massey. Mr. Gardner served as Senior Vice President of Massey from 1994 to 2000 and as General Counsel from 1993 to 2000. From 1991 to 1993, Mr. Gardner was an attorney at the law firm of Hunton & Williams LLP.

James R. Montague has served as a director of our general partner since July 2001. Since 2003, Mr. Montague has been retired. From 2001 to 2002, Mr. Montague served as President of EnCana Gulf of Mexico LLC, a subsidiary of EnCana Corporation, which is in the business of oil and gas exploration and production. From 1996 to June 2001, Mr. Montague served as President of two subsidiaries of International Paper Company, IP Petroleum Company, an exploration and production oil and gas company, and GCO Minerals Company, a company that manages International Paper Company's mineral holdings. Mr. Montague also serves as a director of Memorial Hermann Healthcare System. Mr. Montague serves as the non-executive Chairman of the Board of Davis Petroleum Corp., as a director of Atwood Oceanics, Inc. and as a director of the general partner of Magellan Midstream Partners, L.P.

Marsha R. Perelman has served as a director of our general partner since May 2005. In 1993, Ms. Perelman founded, and since then has been the Chief Executive Officer of, Woodforde Management, Inc., a holding company. In 1983, she co-founded, and from 1983 to 1990 served as the President of, Clearfield Ohio Holdings, Inc., a gas gathering and distribution company. In 1983, she also co-founded, and from 1983 to 1990 served as Vice President of, Clearfield Energy, Inc., a crude oil gathering and distribution company. Ms. Perelman also serves as a director of Penn Virginia.

Frank A. Pici has served as Vice President and Chief Financial Officer of our general partner since September 2001 and as a director since October 2002 and as Vice President and Chief Financial Officer and as a director of PVG's general partner since September 2006. Mr. Pici has also served as Executive Vice President and Chief Financial Officer of Penn Virginia since September 2001. 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, an oil and gas exploration and production company.

Nancy M. Snyder has served as Vice President and General Counsel and as a director of our general partner since July 2001 and as Vice President and General Counsel and as a director of PVG's general partner since September 2006. Ms. Snyder has also served in various capacities with Penn Virginia since 1997, including as Executive Vice President since May 2006, as Senior Vice President from February 2003 to May 2006, as Vice President from December 2000 to February 2003 and as General Counsel and Corporate Secretary since 1997.

Keith D. Horton has served as Co-President and Chief Operating Officer—Coal of our general partner since June 2006 and as President of the Operating Company since September 2001. From July 2001 to June 2006, Mr. Horton served as President and Chief Operating Officer of our general partner. Mr. Horton has also served in various capacities with Penn Virginia since 1981, including as Executive Vice President since December 2000, as Vice President—Eastern Operations from February 1999 to December 2000 and as Vice President from February 1996 to February 1999. Mr. Horton also serves as a director of Penn Virginia and as director of the Virginia Mining Association, the Powell River Project and the Eastern Coal Council.

Ronald K. Page has served as Co-President and Chief Operating Officer—Midstream of our general partner since June 2006 and as President of PVR Midstream LLC since January 2005. From July 2003 to June 2006, Mr. Page served as Vice President, Corporate Development of our general partner. Mr. Page has also served in various capacities with Penn Virginia since July 2003, including as Vice President since May 2005 and as Vice President, Corporate Development from July 2003 to May 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.

Role of the Board of Directors of our General Partner

Our business is managed under the direction of the board of directors of our general partner. The board of directors of our general partner has adopted Corporate Governance Principles outlining its duties. A current copy of our general partner's Corporate Governance Principles is available at the "Governance" section of our website, http://www.pvresource.com, or in print upon request to Penn Virginia Resource GP, LLC, Attention: Secretary, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087, without charge. The board of directors of our general partner meets regularly to review significant developments affecting us and to act on matters requiring its approval.

Code of Business Conduct and Ethics

The board of directors of our general partner has adopted a Code of Business Conduct and Ethics as its "code of ethics" as defined in Item 406 of Regulation S-K, which applies to all directors, officers and employees of our general partner, including its Chief Executive Officer, Chief Financial Officer, principal accounting officer or controller or persons performing similar functions, and all employees of any affiliate of our general partner who provide services to us. A current copy of our general partner's Code of Business Conduct and Ethics is available at the "Governance" section of our website, http://www.pvresource.com, or in print upon request to Penn Virginia Resource GP, LLC, Attention: Secretary, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087, without charge.

Executive Sessions and Meetings of Independent Directors; Communications with the Board

Our general partner's Independent Directors, as such term is defined in "Item 13—Certain Relationships and Related Transactions, and Director Independence—Director Independence," meet during regularly scheduled executive sessions without management as well as during meetings which are scheduled on an as needed basis. John P. DesBarres, an Independent Director, presides over executive sessions. Unitholders and other interested parties may communicate any concerns they have regarding us by contacting Mr. DesBarres in writing c/o Secretary, Penn Virginia Resource GP, LLC, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087.

Committees of the Board of Directors of our General Partner

The board of directors of our general partner has an audit committee, a conflicts committee and a compensation and benefits committee.

Audit Committee. Messrs. DesBarres, Gardner and Montague are the members of the audit committee of our general partner, and each such member is an Independent Director. Mr. DesBarres is an "audit committee financial expert" as defined in Item 407(d)(5) of Regulation S-K. The audit committee of our general partner is responsible for the appointment, compensation, evaluation and termination of our independent registered public accountants, and oversees the work, internal quality-control procedures and independence of the independent registered public accountants. The committee discusses with management and the independent registered public accountants our annual audited and quarterly unaudited financial statements and recommends to the board of directors of our general partner that our annual audited financial statements be included in our Annual Report on Form 10-K. The committee also discusses with management earnings press releases and guidance provided to analysts. The committee also provides oversight with respect to business risk matters, compliance with ethics policies, compliance with legal and regulatory requirements and performance of our internal audit function. The committee has established procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, auditing and other matters and the confidential anonymous submission by employees of concerns regarding questionable accounting, auditing and other matters. The committee may obtain advice and assistance from outside legal, accounting or other advisors as it deems necessary to carry out its duties.

Conflicts Committee. Messrs. DesBarres, Gardner and Montague are the members of the conflicts committee of our general partner, and each such member is an Independent Director. The conflicts committee of our general partner reviews transactions between or among us and Penn Virginia or PVG, or any of their affiliates, and any other transactions involving us or our affiliates that the board of directors of our general partner believes may involve conflicts of interest. The conflicts committee then determines whether such transactions are fair and reasonable to us, and whether our general partner has upheld the fiduciary or other duties it owes to us. The committee may obtain advice and assistance from outside legal, financial or other advisors as it deems necessary to carry out its duties.

Compensation and Benefits Committee. Messrs. Cloues, DesBarres, Gardner and Montague are the members of the compensation and benefits committee of our general partner, and each such member is an Independent Director. The compensation and benefits committee of our general partner assists the compensation and benefits committee of Penn Virginia, or the Penn Virginia Committee, when the Penn Virginia Committee determines the compensation for the executive officers of our general partner. See "Item 11—Executive Compensation—Compensation Discussion and Analysis—How Compensation Is Determined—Committee Process." The committee reviews and discusses with management the information contained in Item 11, "Executive Compensation—Compensation Discussion and Analysis," and recommends that such information be included herein. The committee periodically reviews and makes recommendations or decisions regarding our general partner's incentive compensation and equity-based plans, provides oversight with respect to our general partner's other employee benefit plans and reports its recommendations to the board of directors of our general partner. The committee also reviews and makes recommendations to the board of directors of our general partner regarding director compensation policy. The committee may obtain advice and assistance from outside compensation consultants or other advisors as it deems necessary to carry out its duties.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires officers and directors of our general partner and beneficial owners more than 10% of our common units to file, by a specified date, reports of beneficial ownership and changes in beneficial ownership with the SEC and to furnish copies of such reports to us. We believe that all such filings were made on a timely basis in 2007 except as follows:

- one Form 4 of PVG and one Form 4 of Penn Virginia, each of which was inadvertently filed 141 days late by us reporting the acquisition of 33,147 Class B units;
- one Form 4 of PVG and one Form 4 of Penn Virginia, each of which was inadvertently filed 22 days late by us reporting the conversion of 4,045,311 Class B units into 4,045,311 common units;
- one Form 4 of Penn Virginia, which was inadvertently filed one day late by us reporting the transfer of 85,232 restricted units to executive officers and employees of our general partner pursuant to our general partner's long-term incentive plan;
- one Form 4 of Ronald K. Page, which was inadvertently filed one day late by us reporting the sales of 1,100, 400 and 200 common units; and
- one Form 3 of Marsha R. Perelman, which was amended to reflect the ownership of 5,000 common units indirectly owned by a trust, which common units were inadvertently omitted from Ms. Perelman's original Form 3

Item 11 *Executive Compensation*

Compensation Discussion and Analysis

Under the rules established by the SEC, we are required to provide a discussion and analysis of information necessary to an understanding of our compensation policies and decisions regarding our Chief Executive Officer, or CEO, Chief Financial Officer, or CFO, and the other executive officers of our general partner named in the Summary Compensation Table included in this Annual Report on Form 10-K. The required disclosure includes the use of specified tables and a report of the compensation and benefits committee of our general partner. Unless otherwise indicated, all references in this Annual Report on Form 10-K to the "NEOs" refer to the executive officers named in the Summary Compensation Table, and all references to "our Committee" or the "Committee" refer to the compensation and benefits committee of our general partner.

Compensation Structure

Penn Virginia indirectly controls our general partner and owns 100% of our incentive distribution rights and a significant limited partner interest in us. Because of this relationship, and since all of our NEOs are also executives of Penn Virginia and three of our NEOs, including our CEO, devote a majority of their professional time to Penn Virginia, the Penn Virginia Committee sets compensation for our NEOs. A. James Dearlove, our CEO, Frank A. Pici, our Vice President and CFO, and Nancy M. Snyder, our Vice President and General Counsel, who are referred to in this Annual Report on Form 10-K as the "Shared Executives," are employees of Penn Virginia and rendered services not only to us, but also to Penn Virginia and PVG, during 2007. We are responsible for reimbursing to Penn Virginia that portion of the Shared Executives' compensation related to the services they perform for us. The specific portions of compensation reimbursed to Penn Virginia by us depend on the portion of professional time devoted by each Shared Executive to us. The Shared Executives are required to document the amount of professional time they spend rendering services to us. See "How Compensation Is Determined—Committee Process" for a discussion of our Committee's review of such allocations. Two of our NEOs, Keith D. Horton, Co-President and Chief Operating Officer—Coal of our general partner, and Ronald K. Page, Co-President and Chief Operating Officer—Midstream of our general partner, who are referred to in this Annual Report on Form 10-K as the "Partnership Executives," render their services solely to us so we pay all of their compensation.

Objectives of the Compensation Program

The compensation program is based on the following objectives:

- Executive compensation should be industry-competitive so that we can attract, retain and motivate talented executives with appropriate experience and skill sets.
- Executives should be accountable for our performance as well as their own individual performance, so compensation should be tied to both partnership financial measures and individual performance measures.
- Executive compensation should balance and align the short-term and long-term interests of our executives with those of our unitholders, so executive compensation packages should include a mix of cash and equity-based compensation.

Elements of Compensation

We and Penn Virginia pay our NEOs a base salary and give them an opportunity to earn an annual cash bonus and an annual long-term compensation award. In determining these three elements of compensation, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, takes into account certain peer group information obtained by our Committee, the Penn Virginia Committee, each such committee's independent consultants and management, typically focusing on approximately the 50th percentile of the peer benchmarks described below under "How Compensation is Determined—Peer Benchmarks for the Partnership" and "How Compensation is Determined—Peer Benchmarks for Penn Virginia," but also applying its independent judgment to these matters and considering such other factors as it deems relevant.

- *Base Salary*—We and Penn Virginia pay each of our NEOs an industry-competitive salary so that we can attract and retain talented executives. The base salaries also reflect the capabilities, level of experience, tenure, position and responsibilities of our NEOs.
- *Annual Cash Bonus*—We and Penn Virginia give each of our NEOs the opportunity to earn an industry-competitive annual cash bonus. We and Penn Virginia provide this opportunity to create a strong financial incentive for our NEOs to achieve or exceed a combination of partnership and individual goals. The performance criteria by which each NEO is measured and other factors affecting the compensation of our NEOs are described below under the headings "Peer Benchmarks for the Partnership," "Peer Benchmarks for Penn Virginia" and "Partnership, Company and Individual Performance Criteria." In addition to the performance criteria, our Committee and the Penn Virginia Committee may consider any other factors they deem appropriate when awarding annual cash bonuses to our NEOs.
- *Long-Term Compensation Awards*—We and Penn Virginia give each of our NEOs the opportunity to earn an industry-competitive annual long-term compensation award. We and Penn Virginia provide this opportunity to create a strong financial incentive for our NEOs to promote the long-term financial and operational success of the Partnership and to encourage a significant equity stake in the Partnership. We do not have unit ownership requirements for our NEOs. Long-term compensation awards are expressed in dollar values, and we or Penn Virginia pay those awards in the form of restricted units, stock options or restricted stock. The actual numbers of restricted units and shares of restricted stock awarded are based on the NYSE closing prices of our common units and Penn Virginia's common stock on the dates of grant. The actual number of stock options awarded is based on a weighted-average value of all options granted to all classes of Penn Virginia's employees on the date of grant using the Black-Scholes-Merton option-pricing formula. The Shared Executives' long-term compensation awards are split between restricted units of us, on the one hand, and stock options or restricted stock of Penn Virginia, on the other hand. For each Shared Executive, the ratio of the split between Partnership-related long-term compensation and Penn Virginia-related long-term compensation is determined based on the amount of time such Shared Executive devotes to us, on the one hand, and Penn Virginia and PVG, on the other hand. Time devoted to PVG is included with the time devoted to Penn Virginia for the purpose of splitting the type of long-term compensation awards because PVG is a majority-owned subsidiary of Penn Virginia. Executives who render services wholly or predominately to us may receive only restricted units, and executives who render services wholly or predominantly to Penn Virginia or PVG may receive only stock options or restricted stock. Executives who receive Penn Virginia awards are given the opportunity to elect whether to receive those awards in stock options, restricted stock or a combination of both.

How Compensation Is Determined

Committee Process. Because of our relationship with Penn Virginia, as discussed above, the Penn Virginia Committee sets compensation for our NEOs. Our Committee and the PVG Committee assist the Penn Virginia Committee in determining executive compensation for our NEOs in the manner described below. Each of our Committee, the Penn Virginia Committee and the PVG Committee is comprised entirely of Independent Directors.

With respect to Messrs. Horton and Page, who manage our coal and natural resource management-related and natural gas midstream-related operations, respectively, and devote substantially all of their business time to us, our Committee has the primary responsibility to assess all factors relevant to their compensation. Based on that assessment and after discussing such assessment with the PVG Committee, our Committee recommends to the Penn Virginia Committee salary, annual cash bonus and long-term compensation awards for them. Since the Partnership Executives report directly to, and work on a daily basis with, our CEO, our Committee reviews and discusses with our CEO his evaluation of the performance of each of the Partnership Executives prior to making its recommendation regarding such Partnership Executive's compensation, and our Committee gives our CEO's evaluations considerable weight in assessing the amount of compensation to recommend to the Penn Virginia Committee for the Partnership Executives. Our CEO bases his evaluation of each of the Partnership

Executives primarily on whether we met or exceeded certain quantitative partnership performance criteria and whether such Partnership Executive met or exceeded certain specifically tailored job-related individual performance criteria. All such performance criteria are recommended by our CEO and our Committee and set by the Penn Virginia Committee during the preceding year. These performance criteria and other factors relevant to the Partnership Executives' compensation are described in detail below under the headings "Peer Benchmarks for the Partnership" and "Partnership, Company and Individual Performance Criteria." The Penn Virginia Committee then considers our CEO's and our Committee's recommendations as well as other factors it deems relevant and makes the final determination regarding the compensation of each of the Partnership Executives. The Penn Virginia Committee set the 2008 base salary and 2007-related bonus and long-term compensation awards for each of the Partnership Executives in the amounts our Committee recommended.

With respect to the Shared Executives, including our CEO, the Penn Virginia Committee assesses the factors relevant to their compensation and, after discussing such assessment with our Committee and the PVG Committee, sets the salary, annual cash bonus and long-term compensation for each Shared Executive. Since the Shared Executives other than our CEO report directly to, and work on a daily basis with, our CEO, the Penn Virginia Committee reviews and discusses with our CEO his evaluation of the performance of each of the other Shared Executives, and gives considerable weight to our CEO's evaluations, when assessing their performance and determining their compensation. The Penn Virginia Committee bases its evaluation of our CEO, and our CEO bases his evaluation of each of the other Shared Executives, primarily on whether we or Penn Virginia met or exceeded certain quantitative partnership or corporate performance criteria and whether each Shared Executive met or exceeded certain specifically tailored job-related individual performance criteria. All corporate, partnership and individual performance criteria, including those by which our CEO's performance is measured, are recommended by our CEO and set by the Penn Virginia Committee during the preceding year. These performance criteria and other factors relevant to the Shared Executives' compensation are described in detail below under the headings "Peer Benchmarks for the Partnership," "Peer Benchmarks for Penn Virginia" and "Partnership, Company and Individual Performance Criteria." Since we reimburse Penn Virginia for a portion of the Shared Executives' compensation based on the amount of time they devote to us, our Committee reviews the amount of the Shared Executives' time allocable to us each year and determines whether such time allocations are reasonable in light of the business conducted by us during such year.

Peer Benchmarks for the Partnership. In December 2007, our Committee engaged BDO Seidman LLP, or BDO Seidman, as its independent consultant to assist it in a general review of the compensation packages for our NEOs. BDO Seidman identified a peer group of 13 publicly traded limited partnerships, referred to herein as the "BDO Peer Group," against which to benchmark the compensation of our NEOs. The BDO Peer Group includes Alliance Resource Partners, L.P., AmeriGas Partners, L.P., Boardwalk Pipeline Partners, LP, Copano Energy, L.L.C., Crosstex Energy, L.P., Ferrellgas Partners, L.P., Inergy Holdings, L.P., Magellan Midstream Partners, L.P., MarkWest Energy Partners, L.P., Natural Resource Partners L.P., NuStar Energy L.P., Regency Energy Partners LP and Sunoco Logistics Partners L.P. Based on the analysis of base salaries, target bonuses and target long-term compensation opportunities of the BDO Peer Group, the total target compensation of each of our NEOs is appropriate in relation to the BDO Peer Group, but our overall cost of management is significantly lower than that of the BDO Peer Group because we reimburse Penn Virginia for only a portion of the Shared Executives' compensation.

During 2007, Penn Virginia also performed an internal analysis of our peer compensation practices principally as related to chief operating officers, such as the Partnership Executives, who devote substantially all of their time to such peers. Ms. Snyder and Penn Virginia's Vice President, Human Resources worked with the Partnership Executives and other Partnership personnel to identify a peer group for us, comprised of 18 publicly traded limited partnerships, referred to herein as the "Partnership Peer Group," which are comparable to us based on market capitalization and type and geographic location of operations. The Partnership Peer Group consists of Alliance Resource Partners, L.P., Atlas Pipeline Partners, L.P., Boardwalk Pipeline Partners, LP, Buckeye Partners, L.P., Copano Energy, L.L.C., Crosstex Energy, L.P., DCP Midstream Partners, LP, Enbridge Energy Partners, L.P., Energy Transfer Partners, L.P. Hiland Partners, LP, MarkWest Energy Partners, L.P., Magellan Midstream Partners, L.P., Natural Resource Partners L.P., Nustar Energy L.P., ONEOK Partners, L.P., Regency Energy Partners LP, Sunoco Logistics Partners L.P. and TEPPCO Partners, L.P. Penn Virginia studied what the Partnership Peer Group actually paid to executives during or with respect to 2006, as reflected in 2007 annual reports on Form 10-K, and during 2007, as reflected in current reports on Form 8-K. The results of Penn Virginia's analysis were generally consistent with the results of BDO Seidman's analysis in that Penn Virginia's analysis showed that the total compensation of the Partnership Executives falls between the 50th and 75th percentile of the Partnership Peer Group, but that our overall cost of management is significantly lower than that of the Partnership Peer Group because we reimburse Penn Virginia for only a portion of the Shared Executives' compensation. See "How Compensation is Determined—Partnership, Company and Individual Performance Criteria" for information regarding the competitive compensation positioning of individual NEOs.

Peer Benchmarks for Penn Virginia. In December 2007, the Penn Virginia Committee engaged Hewitt Associates LLC, or Hewitt, as its independent compensation consultant to assist it in a general review of the compensation packages for the Shared Executives and the president of Penn Virginia's oil and gas subsidiary. As part of its analysis, Hewitt discussed with each of these Penn Virginia executives our and Penn Virginia's businesses and Penn Virginia's current compensation practices. Hewitt identified a peer group, referred to herein as the "Hewitt Peer Group," against which to benchmark the compensation of these Penn Virginia executives. The Hewitt Peer Group, which is comprised of 18 oil and gas companies included in Hewitt's oil and gas compensation database and similar to Penn Virginia based on revenues, assets, capitalization, scope of operations and total shareholder return, includes Berry Petroleum Company, Cabot Oil & Gas Corporation, Cimarex Energy Co., Comstock Resources, Inc., Denbury Resources Inc., Encore Acquisition Company, Forest Oil Corporation, Goodrich Petroleum Corporation, Petroleum Development Corporation, PetroQuest Energy, Inc., Plains Exploration & Production Company, Quicksilver Resources Inc., Range Resources Corporation, Southwestern Energy Company, St. Mary Land & Exploration Company, Stone Energy Corporation, Swift Energy Company and Whiting Petroleum Corporation. Based on the analysis of base salaries, target bonuses and target long-term compensation opportunities of the Hewitt Peer Group, total 2007 compensation opportunities for the Shared Executives and the president of Penn Virginia's oil and gas subsidiary, as a group, were 11% below the 25th percentile, and 43% below the 50th percentile, of the Hewitt Peer Group.

During 2007, Penn Virginia also performed an internal analysis of its peer compensation practices. Ms. Snyder and Penn Virginia's Vice President, Human Resources worked with the president of Penn Virginia's oil and gas subsidiary and Penn Virginia's investor relations manager to identify a peer group of 17 oil and gas companies, referred to herein as the "Penn Virginia Peer Group," which are comparable to Penn Virginia based on revenues, market capitalization and type and geographic location of operations, and some of which were also included in the Hewitt Peer Group. The Penn Virginia Peer Group includes Berry Petroleum Company, Bill Barrett Corporation, Cabot Oil & Gas Corporation, Carrizo Oil & Gas, Inc., Clayton Williams Energy, Inc., CNX Gas Corporation, Delta Petroleum Corporation, EXCO Resources, Inc., Goodrich Petroleum Corporation, Parallel Petroleum Corporation, Petrohawk Energy Corporation, PetroQuest Energy, Inc., Quicksilver Resources Inc., Range Resources Corporation, Southwestern Energy Company and St. Mary Land & Exploration Company. Penn Virginia studied what the Penn Virginia Peer Group actually paid to executives during or with respect to 2006, as reflected in 2007 proxy statements and annual reports on Form 10-K, and during 2007, as reflected in current reports on Form 8-K. The overall results of Penn Virginia's analysis were generally consistent with the results of Hewitt's analysis in that Penn Virginia's analysis showed that the total compensation of the Shared Executives and the president of Penn Virginia's oil and gas subsidiary, as a group, was well below the 50th percentile of the Company Peer Group. See "How Compensation is Determined—Partnership, Company and Individual Performance Criteria" for information regarding the competitive compensation positioning of individual NEOs.

Partnership, Company and Individual Performance Criteria. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, targets the amount of salary, cash bonus and long-term compensation awards for each NEO at approximately the 50th percentile of comparable executives of our peers, in the case of the Partnership Executives, or comparable executives of Penn Virginia's peers, in the case of the Shared Executives. However, given the importance of executive accountability for our and Penn Virginia's performance as well as for individual performance, our Committee, the Penn Virginia Committee and the PVG Committee recognize that compensation for any NEO could exceed such 50th percentile targets, reflecting a reward for exceptional Partnership, Penn Virginia or individual performance, or be lower than such 50th percentile targets, reflecting Partnership, Penn Virginia or individual underperformance. To measure specific performance, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, uses certain quantitative Partnership and Penn Virginia performance criteria and certain quantitative and qualitative individual performance criteria which measure achievement and contribution to us or Penn Virginia. Our Committee, the Penn Virginia Committee and the PVG Committee believe that these performance criteria for each NEO are focused on factors over which such NEO has some control and which should have a positive effect on our and Penn Virginia's operations and on the price of our common units or Penn Virginia's common stock or PVG's common units. The weight given any one criterion and the mix of criteria included in determining amounts of compensation vary among our NEOs depending on their positions and principal areas of responsibility. The relevance and the relative importance of any of these criteria change from time to time, even within the same year, depending on our and Penn Virginia's strategic objectives, operational needs and general business and regulatory environments. For this reason, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, may change these performance criteria from year to year, may assign an aggregate weight to several performance criteria applicable to a NEO or may consider adding criteria which were not known at the time the original criteria were established, or deleting criteria which became obsolete or unimportant.

Compensation of A. James Dearlove, CEO. In February 2008, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, set Mr. Dearlove's 2008 base salary at $450,000, representing a 18.4% increase over his 2007 base salary. This increase was based on the results of Hewitt's and Penn Virginia's peer compensation studies, which showed that Mr. Dearlove's 2007 salary was not industry-competitive in that it was below the 25th percentile of the

Hewitt Peer Group and significantly below the 50th percentile of the Penn Virginia Peer Group. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, also awarded to Mr. Dearlove a cash bonus of $550,000, or approximately 145% of his 2007 base salary, and a long-term compensation award valued at $2,000,000, or approximately 526% of his base salary. We reimbursed Penn Virginia for 38% of Mr. Dearlove's 2007-related bonus and long-term compensation awards, or $209,000 and $760,000. In making 2007-related bonus and long-term compensation awards to Mr. Dearlove in these amounts, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, considered our, Penn Virginia's and his performance against the following criteria:

CORPORATE AND PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Growth in our distributable cash flow per unit from December 31, 2006 to December 31, 2007 (1)	Target – $1.93 Stretch – $2.05	Exceeded target by $0.04 per unit
Growth in Penn Virginia's net asset value per share from December 31, 2006 to December 31, 2007 (2)	Target – 11% Stretch – 15%	Exceeded stretch by 33%

INDIVIDUAL CRITERIA	ASSESSMENT
Continually assess and modify our, Penn Virginia's and PVG's strategy as needed to accommodate changes in energy and general business environments	Principal architect of our, Penn Virginia's and PVG's individual and collective strategies as presented to the board of directors of our general partner, Penn Virginia's board of directors and the board of directors of PVG's general partner Facilitated Penn Virginia's strategy to grow through the drillbit by directing planning and budgeting of approximately $428 million for development and exploratory drilling in 2008 and spending of $520 million for development and exploratory drilling in 2007 Promoted Penn Virginia's strategy to increase lower-risk drilling inventory by overseeing ten acquisitions, or the "Oil and Gas Acquisitions," of an aggregate of approximately $130 million of oil and gas assets principally in East Texas Cotton Valley, Mid-Continent and Mississippi Selma Chalk Promoted both our and Penn Virginia's strategy to utilize our relationship with each other and our strategy to diversify revenues by facilitating and overseeing Penn Virginia's tax efficient disposition to us of $31 million of non-core oil and gas royalty interests and execution of agreement under which we will gather and process Penn Virginia's gas through our newly constructed East Texas gas processing plant, or, together, the "PVA/PVR Transactions" Promoted our strategy to grow coal reserves and diversify our business by overseeing four acquisitions, or the "PVR Coal Acquisitions," whereby our coal and natural resource management division, or "PVR Coal," acquired approximately 70 million tons of coal reserves, 62,000 acres of prime forestland and the oil and gas royalty interests described above Promoted our strategy to expand our natural gas midstream operations by overseeing execution of agreement by our natural gas midstream division, or "PVR Midstream," to purchase a pipeline, or the "Midstream Transaction," expected to expand our gas gathering and processing footprint, expansion of two of PVR Midstream's existing processing facilities and construction of new processing plant in East Texas Oversaw strategic rebalancing of Penn Virginia's capital structure through December 2007 $172.5 million common stock/$230 million convertible notes dual tranche public offering, or the "Dual Tranche Offering" Recognized advantage of PVG as financial partner to us to facilitate significant transactions and helped create several possible structures to accomplish this in future transactions
Increase Penn Virginia's market value per barrel of oil and Mcf of natural gas	Oversaw aggressive investor relations program, aggressive and successful oil and gas development program and PVG's December 2006 initial public offering, which Penn Virginia believes defined PVG's value to Penn Virginia and caused an increase in its stock

	price unrelated to the market value of PVG
Work with Penn Virginia's board of directors to maintain current succession plan for CEO position	Succession plan and internal candidate assessments reviewed with Penn Virginia's board of directors on annual and as-needed basis
Represent us, Penn Virginia and PVG to investment community	Eight quarterly public teleconferences and eight investor conferences, including more than 70 "one-on-one" investor meetings, three sales force presentations and four road shows held during 2007
Ensure ethical "tone at the top" regarding compliance by us, Penn Virginia and PVG with all applicable laws, rules and regulations	We, Penn Virginia and PVG have excellent regulatory and ethical track record
Other considerations	Penn Virginia's stock price rose by approximately 25% in 2007 Penn Virginia's 2007 total shareholder return was near the 75th percentile of Hewitt Peer Group Significant complexity of managing three separate publicly traded entities engaged in multiple businesses

(1) "Distributable cash flow per unit," as we and Penn Virginia compute it, is equal to (x) the sum of our (A) operating income plus (B) DD&A expenses minus (y) the sum of our (A) interest expense plus (B) maintenance capital expenditures, divided by (z) the total number of our common units issued and outstanding.

(2) "Net asset value per share," as Penn Virginia computes it, is equal to (x) the value of Penn Virginia's proved oil and natural gas reserves and other assets (principally, the market value of Penn Virginia's ownership interest in PVG), minus (y) Penn Virginia's debt not related to us, divided by (z) the total number of shares of Penn Virginia's common stock issued and outstanding.

In addition to the assessments described above, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, considered Hewitt's market data which showed that Mr. Dearlove's target total cash compensation, including the portion reimbursed to Penn Virginia by us, was below the 25th percentile, and his target long-term compensation, including our portion, was well below the 50th percentile, of CEOs in the Hewitt Peer Group. Penn Virginia's internal compensation analysis had similar results showing that neither Mr. Dearlove's total compensation nor his long-term compensation, including the portions reimbursed to Penn Virginia by us, was industry-competitive. The Penn Virginia Committee believes, and Hewitt's data confirmed, that the amounts of 2007-related bonus and long-term compensation awarded to Mr. Dearlove, when combined with his 2008 base salary, comprise an industry-competitive compensation package that falls at approximately the 50th percentile of CEOs in the Hewitt Peer Group. Further, the Penn Virginia Committee believes that this compensation appropriately reflects our, Penn Virginia's and Mr. Dearlove's 2007 performance. Our Committee reviewed Mr. Dearlove's time allocated to us during 2007 and concluded that such allocation was reasonable given the business conducted by us during 2007.

Compensation of Frank A. Pici, Vice President and CFO. In February 2008, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, set Mr. Pici's 2008 base salary at $275,000, representing a 4.6% increase over his 2007 base salary. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, also awarded Mr. Pici a cash bonus of $220,000, or approximately 84% of his 2007 base salary, and a long-term compensation award valued at $800,000, or approximately 304% of his 2007 base salary. We reimbursed Penn Virginia for 28% of Mr. Pici's 2007-related cash bonus and long-term compensation awards, or $61,600 and $224,000. In making 2007-related bonus and long-term compensation awards to Mr. Pici in these amounts, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, considered our, Penn Virginia's and his performance against the following criteria:

CORPORATE AND PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Growth in our distributable cash flow per unit from December 31, 2006 to December 31, 2007	Target – $1.93 Stretch – $2.05	Exceeded target by $0.04 per unit
Growth in Penn Virginia's net asset value per share from December 31, 2006 to December 31, 2007	Target – 11% Stretch – 15%	Exceeded stretch by 33%
INDIVIDUAL CRITERIA	**ASSESSMENT**	
Contribute to formulating and executing individual and overall strategies for us, Penn Virginia and PVG and define financial role, if any, for PVG	Contributed to formulation of individual and overall strategies for us, Penn Virginia and PVG Championed and oversaw strategic and financial analyses related to rebalancing Penn Virginia's capital structure through Dual Tranche	

	Offering, including cost-reducing complex call spread structure
	Helped create possible structures to accomplish financial role for PVG in significant Partnership acquisitions
Oversee financial planning, modeling and evaluation of potential acquisitions by us and Penn Virginia and promote efficiency in any transactions between us and Penn Virginia	Contributed to or oversaw strategic and economic evaluations of all Oil and Gas Acquisitions, PVA/PVR Transactions, PVR Coal Acquisitions and Midstream Transaction
	Oversaw significant improvement in financial planning models
	Promoted efficiency of financial analyses in PVA/PVR Transactions
Monitor and, if necessary, set hedging policy for our natural gas midstream business and Penn Virginia's oil and gas exploration and production business and set policy for SOX compliance	Current hedging policies for PVR Midstream's and Penn Virginia's businesses in place and monitored regularly
	SOX compliance policies in place, and we, Penn Virginia and PVG have had no SOX-related regulatory compliance problems
Develop succession plan for the position of CFO	Assessment of internal candidates reviewed with CEO annually
Overall responsibility for finance, accounting, tax, audits, investor relations and information technology	Oversaw conversion to new accounting system
	Excellent relationship with our and Penn Virginia's bank groups comprised of 21 banks
	Expanded and improved investor relations function
	Expanded and improved structure and efficiency of financial planning group
Other considerations	Penn Virginia's stock price rose by approximately 25% in 2007
	Penn Virginia's 2007 total shareholder return was near the 75th percentile of Hewitt Peer Group
	Significant complexity of managing finance, tax, accounting, treasury, investor relations and information technology-related aspects of three separate publicly traded entities engaged in multiple businesses

In addition to the assessments described above, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, considered Hewitt's market data which showed that Mr. Pici's target total cash compensation, including the portion reimbursed to Penn Virginia by us, was not industry-competitive in that it was below the 25th percentile, and his target long-term compensation, including our portion, was well below the 50th percentile, of the Hewitt Peer Group. Penn Virginia's internal compensation analysis showed that, including our portion, Mr. Pici's actual total cash compensation was generally industry-competitive, but his long-term compensation was not competitive. The Penn Virginia Committee believes, and Hewitt's data confirmed, that the amounts of 2007-related bonus and long-term compensation awarded to Mr. Pici, when combined with his 2008 base salary, comprise an industry-competitive compensation package that falls at approximately the 50th percentile of CFOs in the Hewitt Peer Group. Further, the Penn Virginia Committee believes that this compensation appropriately reflects our, Penn Virginia's and Mr. Pici's 2007 performance. Our Committee reviewed Mr. Pici's time allocated to us during 2007 and concluded that such allocation was reasonable given the business conducted by us during 2007.

Compensation of Nancy M. Snyder, Vice President and General Counsel. In February 2008, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, set Ms. Snyder's 2008 base salary at $265,000, representing a 15.2% increase over her 2007 base salary. This increase was based on the results of Hewitt's and Penn Virginia's peer compensation analyses, which showed that Ms. Snyder's 2007 salary was below the 25th percentile of the Hewitt Peer Group and significantly below the 50th percentile of the Penn Virginia Peer Group, and also on the fact that Ms. Snyder's responsibilities were expanded in October 2007 to include managing Penn Virginia's human resources department. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, also awarded Ms. Snyder a cash bonus of $215,000, or approximately 93% of her 2007 base salary, and a long-term compensation award valued at $800,000, or approximately 348% of her 2007 base salary. We reimbursed Penn Virginia for 33% of Ms. Snyder's 2007-related cash bonus and long-term compensation awards, or $70,950 and $264,000. In making 2007-related bonus and long-term compensation awards to Ms. Snyder in these amounts, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, considered our, Penn Virginia's and her performance against the following criteria:

CORPORATE AND PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Growth in our distributable cash flow per unit from	Target – $1.93	Exceeded target by

December 31, 2006 to December 31, 2007	Stretch – $2.05	$0.04 per unit
Growth in Penn Virginia's net asset value per share from December 31, 2006 to December 31, 2007	Target – 11% Stretch – 15%	Exceeded stretch by 33%

INDIVIDUAL CRITERIA	ASSESSMENT
Negotiate issues related to our and Penn Virginia's acquisitions, dispositions and other transactions	Negotiated or oversaw negotiation of Dual Tranche Offering, all Oil and Gas Acquisitions, PVA/PVR Transactions, PVR Coal Acquisitions and Midstream Transaction, numerous final acquisition bids, joint operating agreements, master service agreements, gas processing and transportation agreements, leases, easements and other day-to-day transactions
	All Oil and Gas Acquisitions, PVA/PVR Transactions, PVR Coal Acquisitions and Midstream Transaction completed in-house with outside counsel retained only with respect to local title opinions or advice related to specialties such as tax and local environmental matters
Facilitate efficiency of transactions between us and Penn Virginia	PVA/PVR Transactions accomplished and potential conflicts identified and resolved
Advise us and Penn Virginia with respect to business and strategic transactional issues	Contributed to formulation of our, Penn Virginia's and PVG's individual and collective strategy in general and with respect to all transactions described above
Advise and assist other officers of our general partner, Penn Virginia and PVG's general partner regarding day-to-day legal matters, including those related to banking, insurance and financing	Advised regarding negotiation of call spread structure in Dual Tranche Offering and advised regarding, or completed or oversaw in-house completion of, several credit agreement amendments for us and Penn Virginia and renewal of our and Penn Virginia's directors and officers liability and other insurance policies
Oversee regulatory compliance and governance requirements for us, Penn Virginia and PVG	We, Penn Virginia and PVG have excellent legal compliance track record
	Monitored and reacted in timely manner to changes in laws, rules and regulations
	Reviewed and suggested amendment, as necessary, of all governance and other documents, including committee charters, codes of conduct, whistleblower policies, trading policies and equity plans for us, Penn Virginia and PVG
Oversee outside legal counsel, in-house legal staff and corporate secretary function	Oversaw outside litigation or dispute related work with five positive outcomes in five disputes
	Directed outside counsel with respect to Dual Tranche Offering
	Oversaw in-house legal staff, which, in addition to transactional work and day-to-day contractual matters, reviewed or prepared our, Penn Virginia's and PVG's periodic filings and governance documents, including more than 48 Form 8-Ks, 92 sets of board and committee minutes and 175 Form 4s
Other considerations	Penn Virginia's stock price rose by approximately 25% in 2007
	Penn Virginia's 2007 total shareholder return was near the 75th percentile of Hewitt Peer Group
	Expanded and improved structure and efficiency of human resource department
	Oversaw compensation peer group analyses
	Good ability to select and manage personnel
	Significant complexity of managing legal, human resource aspects, as well as corporate secretary function, of three separate publicly traded entities engaged in multiple businesses

In addition to the assessments described above, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, considered Hewitt's market data which showed that Ms. Snyder's target total cash compensation, including the portion reimbursed to Penn Virginia by us, was below the 25th percentile and her target long-term compensation, including our portion, was well below the 50th percentile of the Hewitt Peer Group. Penn Virginia's internal compensation analysis showed that her actual total cash compensation was generally industry-competitive, but her actual long-term compensation was not competitive. The Penn Virginia Committee believes, and the Company Peer Group data confirmed, that the amounts of 2007-related bonus and long-term compensation awarded to Ms. Snyder, when combined with her 2008 base salary, comprise an industry-competitive compensation package that falls at approximately the 50th percentile of general counsels in the Company Peer Group who have responsibilities comparable to those of Ms. Snyder. Further, the Penn Virginia Committee believes that this compensation appropriately reflects our, Penn Virginia's and Ms. Snyder's 2007 performance. Our Committee reviewed Ms. Snyder's time allocated to us during 2007 and concluded that such allocation was reasonable given the business conducted by us during 2007.

Compensation of Keith D. Horton, Chief Operating Officer—Coal. In February 2008, our Committee, with the assistance of the PVG Committee, recommended and the Penn Virginia Committee set Mr. Horton's 2008 base salary at $280,000, representing a 3.7% increase over his 2007 base salary. Our Committee, with the assistance of the PVG Committee, also recommended and the Penn Virginia Committee, with the concurrence of our Committee, awarded Mr. Horton a cash bonus of $185,000, or approximately 69% of his 2007 base salary, and a long-term compensation award valued at $400,000, or approximately 148% of his 2007 base salary. We paid all of Mr. Horton's 2007-related bonus and long-term compensation awards. In recommending or making 2007-related bonus and long-term compensation awards to Mr. Horton in these amounts, our Committee and the Penn Virginia Committee, with the assistance of the PVG Committee, considered our and his performance against the following criteria:

PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Increase in our coal and natural resource management-related EBITDA from December 31, 2006 to December 31, 2007	Target – $94 million Stretch – $98 million	EBITDA 2% under target, but exceeded budget of $91.2 million by approximately 1%
Increase in our coal reserves from December 31, 2006 to December 31, 2007	Target – 100 million tons Stretch – 150 million tons	Coal reserves increased by 70 million tons, but also completed strategically important $93 million acquisition of 62,000 acres of prime forestland and $31 million acquisition of oil and gas royalty interests which diversified our revenues sources
Increase in revenues from non-coal reserve assets, such as railcar loading facilities, processing plants and other infrastructure and timber from December 31, 2006 to December 31, 2007	Target – $9 million Stretch – $11 million	Non-coal reserve revenues increased by $8 million Evaluated acquiring or constructing several river terminals and loadout facilities Worked to expand efforts of Coal Handling Solutions LLC, our coal handling joint venture with Massey Energy Company
INDIVIDUAL CRITERIA	**ASSESSMENT**	
Develop a succession plan	Assessment of internal candidates reviewed with CEO annually	
Other considerations	We increased distributions by 10% during 2007 We had record distributable cash flow in 2007	

(1) We and Penn Virginia define coal and natural resource management-related EBITDA as the sum of coal and natural resource management segment-related (x) operating income plus (y) DD&A expenses.

In addition to the assessments described above, our Committee and the Penn Virginia Committee, with the assistance of the PVG Committee, considered BDO Seidman's market data which showed that Mr. Horton's total target cash compensation was industry-competitive and Penn Virginia's internal compensation analysis which showed that Mr. Horton's actual total compensation was industry-competitive. Our Committee and the Penn Virginia Committee believe, and BDO Seidman's data confirmed, that the amounts of 2007-related bonus and long-term compensation awarded to Mr. Horton, when combined with his 2008 base salary, continue to comprise an industry-competitive compensation package that falls between the 50th and 75th percentiles of chief operating officers in the BDO Peer Group and the Partnership Peer Group. Further, our Committee and the Penn Virginia Committee believe that this compensation appropriately reflects our and Mr. Horton's 2007 performance. These amounts also reflect Mr. Horton's strong leadership abilities, significant industry experience, tenure at the Partnership and our desire to retain his services, as well as our Committee's and the Penn Virginia Committee's desire to facilitate, to the extent reasonable and appropriate, the opportunity for all of our NEOs to earn reasonably comparable compensation notwithstanding that they work in different industries that have different compensation practices.

Compensation of Ronald K. Page, Chief Operating Officer—Midstream. In February 2008, our Committee, with the assistance of the PVG Committee, recommended and the Penn Virginia Committee set Mr. Page's 2008 base salary at $260,000, representing a 10.6% increase over his 2007 base salary. Since Mr. Page has responsibilities similar to those of Mr. Horton, our Committee, with the assistance of the PVG Committee, recommended, and the Penn Virginia Committee agreed, that Mr. Page's base salary should be increased to amount comparable to Mr. Horton's 2008 base salary. Our Committee, with the assistance of the PVG Committee, also recommended and the Penn Virginia Committee, with the concurrence of our Committee, awarded Mr. Page a cash bonus of $170,000, or approximately 72% of his 2007 base salary, and a long-term compensation award valued at $400,000, or approximately 170% of his 2007 base salary. We paid all of Mr. Page's 2007-related bonus and long-term compensation awards. In recommending or making 2007-related bonus and long-term compensation awards to Mr. Page in these amounts, our Committee and the Penn Virginia Committee considered our and his performance against the following criteria:

PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Increase in our natural gas midstream-related EBITDA from December 31, 2006 to December 31, 2007	Target – $51.3 million Stretch – $54 million	Exceeded stretch by 3.7%
Increase in our 2007 natural gas midstream-related EBITDA from acquisitions completed during 2007	Target – $5 million Stretch – $10 million	PVR Midstream completed no acquisitions in 2007
INDIVIDUAL CRITERIA	**ASSESSMENT**	
Complete Spearman plant expansion by October 2007 and complete evaluation of construction of new processing plant in East Texas, or the "New East Texas Plant"	Spearman expansion expected to be completed in March 2008 due to equipment delivery issues New East Texas Plant expected to begin operating in April 2008	
Expand size and reach of existing facilities	Expended $38.7 million in 2007 expansion projects resulting in increase of 140 MMcfd of inlet gas capacity	
Identify and complete joint venture opportunities with Penn Virginia Oil & Gas Corporation, or "PVOG"	Completed transaction whereunder PVR Midstream will gather and process PVOG's East Texas gas through New East Texas Plant	
Develop a succession plan	Succession plan developed, time and effort spent to develop personnel and assessment of internal candidates reviewed with CEO annually	
Other considerations	We increased distributions by 10% during 2007 We had record distributable cash flow in 2007 PVR Midstream creative and aggressive in developing and pursing new opportunities	

(1) We and Penn Virginia define natural gas midstream-related EBITDA as the sum of natural gas midstream segment-related (x) operating income plus (y) DD&A expenses.

In addition to the assessments described above, our Committee and the Penn Virginia Committee, with the assistance of the PVG Committee, considered BDO Seidman's market data which showed that Mr. Page's total target cash compensation was industry-competitive and Penn Virginia's internal compensation analysis which showed that Mr. Page's actual total compensation was industry-competitive. Our Committee and the Penn Virginia Committee believe, and BDO Seidman's data confirmed, that the amounts of 2007-related bonus and long-term compensation awarded to Mr. Page, when combined with his 2008 base salary, continue to comprise an industry-competitive compensation package that falls between the 50th and 75th percentiles of chief operating officers in the BDO Peer Group and the Partnership Peer Group. Further, our Committee and the Penn Virginia Committee believe that this compensation appropriately reflects our and Mr. Page's 2007 performance. These amounts also reflect Mr. Page's strong leadership abilities, significant industry experience and our desire to retain his services, as well as our Committee's and the Penn Virginia Committee's desire to facilitate, to the extent reasonable and appropriate, the opportunity for all of our NEOs to earn reasonably comparable compensation notwithstanding that they work in different industries that have different compensation practices.

Summary Compensation Table

The following table sets forth the compensation paid by us, during or with respect to the years ended December 31, 2007 and 2006, to our CEO, our CFO and our general partner's three other most highly compensated executive officers for services rendered to us and our subsidiaries:

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) (1)	All Other Compensation ($) (2)	Total ($)
A. James Dearlove	2007	144,400	209,000	257,859	15,092	626,351
Chief Executive Officer	2006	183,500	185,000	253,348	19,024	640,872
Frank A. Pici	2007	73,640	61,600	136,006	9,504	280,750
Vice President and Chief Financial Officer	2006	80,960	65,600	125,175	10,200	281,935
Keith D. Horton	2007	270,000	185,000	279,457	34,228	768,685
Co-President and Chief Operating Officer—Coal	2006	260,000	182,000	261,957	32,528	736,485
Ronald K. Page	2007	235,000	170,000	225,828	33,769	664,597
Co-President and Chief Operating Officer—Midstream	2006	220,000	150,000	151,644	32,104	553,748
Nancy M. Snyder	2007	75,900	70,950	124,830	11,295	282,975
Vice President and General Counsel	2006	94,600	77,400	110,444	13,987	296,431

(1) Represents the amounts of expense recognized by us in 2007 and 2006 for financial statement reporting purposes with respect to restricted units previously granted by our Committee to our NEOs in consideration for services rendered to us. These amounts were computed in accordance with SFAS No. 123(R), *Share-Based Payment*, and were based on the NYSE closing prices of our common units on the dates of grant. See Note 12 in the Notes to Consolidated Financial Statements.

(2) Reflects amounts paid or reimbursed by us for (i) automobile allowances, executive health exams and life insurance premiums and (ii) matching and other contributions to our NEOs' 401(k) Plan accounts.

The cash components of our executive compensation consist of a base salary and the opportunity to earn an annual cash bonus. See "Compensation Discussion and Analysis—Elements of Compensation." The amounts of salary and bonus reflected in the Summary Compensation Table above include only amounts paid or reimbursed by us in consideration for services rendered to us by our NEOs and do not include any amounts paid by Penn Virginia to any of our NEOs in consideration for services rendered to Penn Virginia. The specific portions of salary and bonus paid, or reimbursed to Penn Virginia, by us depend on the portion of professional time devoted by each NEO to us. See "Compensation and Discussion Analysis—Compensation Structure" for a description of the manner in which our NEOs are compensated. In 2007, Mr. Dearlove, Mr. Pici and Ms. Snyder devoted approximately 38%, 28% and 33% of his or her professional time to us and, accordingly, we reimbursed Penn Virginia for 38%, 28% and 33% of Mr. Dearlove's, Mr. Pici's and Ms. Snyder's 2007 salary and 2007-related bonus. In 2006, Mr. Dearlove, Mr. Pici and Ms. Snyder devoted approximately 50%, 32% and 43% of his or her professional time to us and, accordingly, we reimbursed Penn Virginia for 50%, 32% and 43% of Mr. Dearlove's, Mr. Pici's and Ms. Snyder's 2006 salary and 2006-related bonus. Because each of the Partnership Executives devoted all of his professional time to us in 2007 and 2006, we paid all of his 2007 and 2006 salaries and 2007- and 2006-related bonuses. For a discussion of the salaries and bonuses paid to the Shared Executives by Penn Virginia, see the Penn Virginia Proxy Statement relating to its 2008 Annual Meeting of Shareholders.

The equity components of our executive compensation program consist of the opportunity to earn awards of restricted units from us and stock options and restricted stock from Penn Virginia. Like the cash component of executive compensation, that portion of the value of each NEO's equity-based compensation paid or reimbursed by us depends on the portion of professional time that each NEO devotes to us. The values of the stock awards reflected in the Summary Compensation Table above include only the values of restricted unit awards granted by our Committee.

Grants of Plan-Based Awards

The following table sets forth the grant date and number of all restricted units granted to our NEOs in 2007 by our Committee with respect to services rendered to us in 2006:

2007 Grants of Plan-Based Awards

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards ($)
A. James Dearlove	February 27, 2007	11,639	312,507
Frank A. Pici	February 27, 2007	4,529	121,604
Keith D. Horton	February 27, 2007	11,732	315,004
Ronald K. Page	February 27, 2007	9,870	265,010
Nancy M. Snyder	February 27, 2007	5,162	138,600

The values of our restricted units were based on the NYSE closing prices of our common units on the dates of grant. All restricted units granted to our NEOs since 2005 vest over a three-year period, with one-third of each award vesting on the first, second and third anniversaries of the grant date unless (i) the restricted unitholder's employment terminates for any reason other than death or retirement as provided in (ii) below, in which event any unvested restricted units are forfeited unless otherwise determined by our Committee, or (ii) the restricted unitholder dies, retires after ten years of employment with our general partner or its affiliate and reaching age 62 or there occurs a change in control of us or our general partner, in which events all restrictions lapse. Restricted units are valued based on the NYSE closing price of our common units on the grant date. Our Committee grants annual compensation-based restricted units during the first quarter of each year after the Penn Virginia Committee, with our Committee's and the PVG Committee's assistance, has concluded its analysis of executive compensation with respect to the preceding year. Our Committee also grants restricted units from time to time in connection with the hiring of new Partnership-related employees and, while it has not done so, may consider such grants in connection with promotions or at such other times as it may deem appropriate. During 2007, we paid quarterly distributions ranging from $0.40 to $0.43 on each restricted unit. The distributions were paid at the same times and in the same amounts as distributions paid to the other holders of our common units and were taken into consideration when determining the values of the restricted units shown previously in the Summary Compensation Table and in the Grants of Plan-Based Awards Table above.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information regarding the numbers and values of restricted units not vested as of December 31, 2007 held by our NEOs on December 31, 2007. The market value of non-vested restricted units is based on the NYSE closing price of our common units on December 31, 2007.

Outstanding Equity Awards at Fiscal Year-End 2007

Name	Stock Awards: Number of Shares or Units of Stock That Have Not Vested (#)		Stock Awards: Market Value of Shares or Units of Stock That Have Not Vested ($)
A. James Dearlove	21,269	(1)	522,579
Frank A. Pici	10,305	(2)	253,194
Keith D. Horton	22,770	(3)	559,459
Ronald K. Page	18,550	(4)	455,774
Nancy M. Snyder	10,022	(5)	246,241

(1) Of these restricted units, 7,236 vested on February 27, 2008, 2,918 will vest on March 3, 2008, 7,236 will vest on February 27, 2009 and 3,879 will vest on February 27, 2010.
(2) Of these restricted units, 3,540 vested on February 27, 2008, 1,716 will vest on March 3, 2008, 3,540 will vest on February 27, 2009 and 1,509 will vest on February 27, 2010.
(3) Of these restricted units, 7,947 vested on February 27, 2008, 2,966 will vest on March 3, 2008, 7,947 will vest on February 27, 2009 and 3,910 will vest on February 27, 2010.
(4) Of these restricted units, 6,404 vested on February 27, 2008, 2,452 will vest on March 3, 2008, 6,404 will vest on February 27, 2009 and 3,290 will vest on February 27, 2010.
(5) Of these restricted units, 3,417 vested on February 27, 2008, 1,470 will vest on March 3, 2008, 3,415 will vest on February 27, 2009 and 1,720 will vest on February 27, 2010.

Vesting of Restricted Units

The following table sets forth the number of common units acquired, and the values realized, by our NEOs upon the vesting of restricted units during 2007:

Option Exercises and Stock Vested in 2007

Name	Stock Awards: Number of Shares Acquired on Vesting (#)	Stock Awards: Value Realized on Vesting ($)
A. James Dearlove	6,276	167,314
Frank A. Pici	3,746	99,877
Keith D. Horton	7,006	186,894
Ronald K. Page	5,566	148,442
Nancy M. Snyder	3,168	84,457

Nonqualified Deferred Compensation

The following table sets forth certain information regarding compensation paid by both our general partner and Penn Virginia and deferred by our NEOs under Penn Virginia's Supplemental Employee Retirement Plan:

2007 Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($) (1)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY ($) (2)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($) (3)
A. James Dearlove	218,546	0	76,115	0	665,389
Frank A. Pici	349,967	0	88,642	0	1,683,863
Keith D. Horton	1,350	0	927	0	19,296
Ronald K. Page...............	50,458	0	13,887	0	99,366
Nancy M. Snyder	183,058	0	124,512	0	1,087,528

(1) All of these amounts are included in the amounts of salary and bonus for 2007 reported by us or Penn Virginia in the Summary Compensation Tables included in this Annual Report on Form 10-K and Penn Virginia's Proxy Statement relating to its 2008 Annual Meeting of Shareholders.

(2) These amounts are not reported in the Summary Compensation Table because they are not above-market or preferential earnings.

(3) Except with respect to aggregate contributions by Penn Virginia of $22,923 on behalf of Mr. Pici in 2001 and 2002, these amounts reflect only salaries and bonuses paid to our NEOs and earnings on those salaries and bonuses. All such salary and bonus amounts were previously reported by us or Penn Virginia as compensation to our NEOs in the Summary Compensation Tables included in our Annual Reports on Form 10-K and Penn Virginia's Proxy Statements.

The Penn Virginia Corporation Supplemental Employee Retirement Plan, or the SERP, allows all of Penn Virginia's and its affiliates' employees, including employees of our general partner, whose salaries exceeded $125,000 in 2007 to defer receipt of up to 100% of their salary, net of their salary deferrals under Penn Virginia's 401(k) Plan, and up to 100% of their annual cash bonuses. The amounts reported in the Nonqualified Deferred Compensation Table above include not only contributions and earnings thereon related to deferred salaries and bonuses paid for services rendered to us, but also contributions and earnings thereon related to deferred salaries and bonuses paid for services rendered to Penn Virginia. All deferrals under the SERP are credited to an account maintained by Penn Virginia and are invested by Penn Virginia, at the employee's election, in Penn Virginia's common stock or in certain mutual funds made available by Penn Virginia and selected by the employee. Since all amounts deferred under the SERP consist of previously earned salary or bonus, all SERP participants are fully vested at all times in all amounts credited to their accounts. Amounts held in a participant's account will be distributed to the participant on the earlier of the date on which such participant's employment terminates or there occurs a change of control of Penn Virginia. Neither we nor Penn Virginia are required to make any contributions to the SERP. Since Penn Virginia established the SERP in 1996, it has contributed an aggregate of $27,308 in 2001 and 2002 to the SERP in connection with offers of employment to Mr. Pici and another executive of Penn Virginia, but has made no other contributions to the SERP.

Penn Virginia has established a rabbi trust to fund the benefits payable under the SERP. Other than the $27,308 of Penn Virginia contributions described above, the assets of the rabbi trust consist of the cash amounts of salary and bonus already earned and deferred by our NEOs and other employees under the SERP and the securities in which those amounts have been invested. Assets held in the rabbi trust are designated for the payment of benefits under the SERP and are not available for Penn Virginia's general use. However, the assets held in the rabbi trust are subject to the claims of Penn Virginia's general creditors, and SERP participants may not be paid in the event of Penn Virginia's insolvency.

Long-Term Incentive Plan

Our general partner has adopted the Third Amended and Restated Penn Virginia Resource GP, LLC Long-Term Incentive Plan. Our long-term incentive plan permits the grant of awards covering an aggregate of 600,000 common units to employees and directors of our general partner and employees of its affiliates who perform services for us. Awards under our long-term incentive plan can be in the form of common units, restricted units, unit options, phantom units and deferred common units. Our long-term incentive plan is administered by our Committee.

Our general partner's board of directors in its discretion may terminate or amend our long-term incentive plan at any time with respect to any units for which a grant has not yet been made. Our general partner's board of directors also has the right to alter or amend our long-term incentive plan or any part of the plan from time to time, including increasing the number of units that may be granted subject to unitholder approval as required by the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

Common Units. Our long-term incentive plan permits the grant of common units to employees and directors. Our general partner granted 1,183 common units to a director of our general partner in 2007.

Restricted Units. Our long-term incentive plan permits the grant of restricted units to employees and directors. Our general partner granted 87,033 restricted units to officers and employees of our general partner in 2007. Restricted units vest upon terms established by our Committee. In addition, all restricted units will vest upon a change of control of our general partner or us. If a grantee's employment with, or membership on the board of directors of, our general partner terminates for any reason, the grantee's unvested restricted units will be automatically forfeited unless, and to the extent, that our Committee provides otherwise. 1,267 restricted units were forfeited in 2007. Distributions payable with respect to restricted units may, in our Committee's discretion, be paid directly to the grantee or held by our general partner and made subject to a risk of forfeiture during the applicable restriction period.

Unit Options. Our long-term incentive plan permits the grant of options covering common units to employees and directors. No grants of unit options have been made under our long-term incentive plan. Unit options will have an exercise price that, in the discretion of our Committee, may be less than, equal to or more than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by our Committee. In addition, all unit options will become exercisable upon a change in control of our general partner or us. If a grantee's employment with, or membership on the board of directors of, our general partner terminates for any reason, the grantee's unit options will be automatically forfeited unless, and to the extent, that our Committee provides otherwise. Upon exercise of a unit option, our general partner will acquire common units in the open market or directly from us or any other person or use common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring these common units and the proceeds received by our general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us.

Phantom Units. Our long-term incentive plan permits the grant of phantom units to employees and directors. No grants of phantom units have been made under our long-term incentive plan. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of our Committee, the cash equivalent of the value of a common unit. Our Committee will determine the time period over which phantom units granted to employees and directors will vest. In addition, all phantom units will vest upon a change of control of our general partner or us. If a grantee's employment with, or membership on the board of directors of, our general partner terminates for any reason, the grantee's phantom units will be automatically forfeited unless, and to the extent, our Committee provides otherwise. Common units delivered upon the vesting of phantom units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. Our Committee, in its discretion, may grant tandem distribution equivalent rights with respect to phantom units.

Deferred Common Units. Our long-term incentive plan permits the grant of deferred common units to directors. Our general partner granted 22,209 deferred common units to directors of our general partner in 2007. Each deferred common unit represents one 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. Common units delivered in connection with deferred common units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. Deferred common units awarded to directors receive additional deferred common units equal in value to all cash or other distributions paid by us on account of our common units.

Change-in-Control Arrangements

Our Committee, the Penn Virginia Committee, we and Penn Virginia believe that the Partnership Executives, together with our other senior management and key employees, are a primary reason for our success and that it is important for us to protect them in the event that they lose their jobs under certain circumstances upon a change of control. Four of our five NEOs are age 54 or older, and our NEOs have served the Partnership or Penn Virginia for an average of more than 15 years, with Messrs. Dearlove and Horton and Ms. Snyder having served in various capacities for 30, 25 and 10 years. We and Penn Virginia also believe that, by providing change of control protection, our NEOs will be able to evaluate every Partnership or Penn Virginia opportunity, including a change of control, that may likely result in the termination of their employment, without the distraction of personal considerations. For these reasons, our general partner has entered in change of control severance agreements with the Partnership Executives, which entitle them to the benefits described below and which are substantially the same as the change of control severance agreements entered into between Penn Virginia and each of the Shared Executives. We and Penn Virginia have studied the executive severance arrangements of the Partnership Peer Group and the Penn Virginia Peer Group, as described in their 2007 proxy statements and 2006 annual reports on Form 10-K, and found that the terms of our and Penn Virginia's change of control severance agreements are comparable to those of our and Penn Virginia's peers.

General Partner Executive Change of Control Severance Agreements

On March 9, 2006, our general partner entered into an Executive Change of Control Severance Agreement, or a General Partner Severance Agreement, with each of Messrs. Horton and Page containing the terms and conditions described below.

Term. Each General Partner Severance Agreement has a two-year term which is automatically extended for consecutive one-day periods until terminated by notice from our general partner. If such notice is given, the General Partner Severance Agreement will terminate two years after the date of such notice.

Triggering Events. Each General Partner Severance Agreement provides severance benefits to the Partnership Executive upon the occurrence of two events, or the GP Triggering Events. Specifically, if a change of control of our general partner occurs and, within two years after the date of such change of control, either (a) the Partnership Executive's employment is terminated for any reason other than for cause or the Partnership Executive's inability to perform his duties for at least 180 days due to mental or physical impairment or (b) the Partnership Executive terminates his employment due to a reduction in his authority, duties, title, status or responsibility, a reduction in his base salary, a discontinuation of a material incentive compensation plan in which he participated, the failure of our general partner to obtain an agreement from its successor to assume his General Partner Severance Agreement or his relocation by more than 100 miles of the office of our general partner at which he was working at the time of the change of control, then the Partnership Executive may elect to receive the change of control severance payments and other benefits described below.

Change of Control Severance Benefits. Upon the occurrence of the GP Triggering Events, the Partnership Executive may elect to receive a lump sum, in cash, of an amount equal to three times the sum of his annual base salary plus the highest cash bonus paid to him during the two-year period prior to termination, subject to reduction as described below under "Excise Taxes." In addition, all options to purchase shares of Penn Virginia common stock then held by the Partnership Executive will immediately vest and will remain exercisable for the shorter of three years or the remainder of the options' respective terms and all restricted Penn Virginia stock and all restricted units then held by the Partnership Executive will immediately vest and all restrictions will lapse. Our general partner will also provide certain health and dental benefit-related payments to the Partnership Executive as well as certain outplacement services. Our general partner will not be entitled to reimbursement from us for any of the change of control severance payments or other benefits described in this paragraph.

Excise Taxes. The General Partner Severance Agreements do not include "gross up" benefits to cover excise taxes. If the independent registered public accountants of our general partner determine that any payments to be made or benefits to be provided to the Partnership Executive under his General Partner Severance Agreement would result in him being subject to the excise tax imposed by Section 4999 of the Internal Revenue Code, such payments or benefits will be reduced to the extent necessary to prevent him from being subject to such excise tax.

Restrictive Covenants and Releases. Each General Partner Severance Agreement prohibits the Partnership Executive from (a) disclosing, either during or after his term of employment, confidential information regarding our general partner or its affiliates and (b) until two years after his employment has ended, soliciting or diverting business from our general partner or its affiliates. The General Partner Severance Agreement also requires that, upon payment of the severance benefits to the Partnership Executive, the Partnership Executive and our general partner release each other from all claims relating to the Partnership Executive's employment or the termination of such employment.

Estimated Payments

The following table sets forth the estimated aggregate payments by our general partner to each of Messrs. Horton and Page under his General Partner Severance Agreement assuming that there occurred a change of control of our general partner on December 31, 2007:

Name of Executive Officer	Estimate Severance Payment ($)
Keith D. Horton	1,993,233
Ronald K. Page	1,673,474

Penn Virginia Executive Change of Control Severance Agreements

On February 27, 2006, Penn Virginia entered into an Executive Change of Control Severance Agreement, or a Penn Virginia Severance Agreement, with each of the Shared Executives containing terms and conditions substantially similar to those of the General Partner Severance Agreements. For a discussion of the terms and conditions of, and the estimated payments under, the Penn Virginia Severance Agreements, see the Penn Virginia Proxy Statement relating to its 2008 Annual Meeting of Shareholders. Any payments required to be made to the Shared Executives under the Penn Virginia Severance Agreements will be the sole responsibility of Penn Virginia.

Compensation of Directors

The following table sets forth the aggregate compensation paid by us to the non-employee directors of our general partner during 2007:

2007 Director Compensation

Name	Fees Earned or Paid in Cash ($)		Stock Awards ($) (1)		Total ($)	
Edward B. Cloues, II	38,000		90,000	(2)	128,000	(3)
John P. DesBarres	0	(4)	156,000	(5)	156,000	(6)
James L. Gardner	62,500		90,000	(7)	152,500	(8)
James R. Montague	62,500		90,000	(9)	152,500	(10)
Marsha R. Perelman	0	(11)	122,000	(12)	122,000	(13)

(1) Represents the amounts of expense recognized by us in 2007 for financial statement reporting purposes with respect to the common units and deferred common units previously granted to the non-employee directors of our general partner. These amounts were computed in accordance with SFAS No. 123(R) and are based on the NYSE closing price of our common units on the dates of grant. See Note 12 in the Notes to Consolidated Financial Statements.
(2) As of December 31, 2007, Mr. Cloues had 11,304 deferred common units outstanding.
(3) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer and (c) $18,000 in meeting fees.
(4) Mr. DesBarres elected to receive all cash fees in deferred common units.
(5) As of December 31, 2007, Mr. DesBarres had 17,444 deferred common units outstanding.
(6) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer, (c) $31,000 in meeting fees and (d) $15,000 annual cash retainer as Chairman of the audit committee of our general partner.
(7) As of December 31, 2007, Mr. Gardner had 7,223 deferred common units outstanding.
(8) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer, (c) $30,000 in meeting fees and (d) $10,000 annual cash retainer as a member of the audit committee of our general partner and $2,500 annual cash retainer as Chairman of the compensation and benefits committee of our general partner.
(9) As of December 31, 2006, Mr. Montague had 11,304 deferred common units outstanding.
(10) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer, (c) $30,000 in meeting fees and (d) $10,000 annual cash retainer as a member of the audit committee of our general partner and $2,500 annual cash retainer as Chairman of the conflicts committee of our general partner.
(11) Ms. Perelman elected to receive all cash fees in common units.
(12) As of December 31, 2007, Ms. Perelman had 9,943 deferred common units outstanding.
(13) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer and (c) $12,000 in meeting fees.

Each non-employee director of our general partner receives an annual retainer of $110,000, consisting of $20,000 of cash and $90,000 worth of deferred common units. The actual number of deferred common units awarded in any given year is based upon the NYSE closing price of our common units on the dates on which such awards are granted. Each deferred common unit represents one common unit representing a limited partner interest in us, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of our general partner. The

Chairman of the audit committee of the board of directors of our general partner receives an annual cash retainer of $15,000, and each audit committee member receives an annual cash retainer of $10,000. The Chairmen of all other committees of the board of directors of our general partner receive annual cash retainers of $2,500. In addition to annual retainers, each non-employee director receives $1,000 cash for each board of directors and committee meeting he or she attends. Directors appointed during a year, or who cease to be directors during a year, receive a pro rata portion of cash and deferred common units. Directors may elect to receive any cash payments in common units or deferred common units, and may elect to defer the receipt of any cash or common units they receive under our general partner's Amended and Restated Non-Employee Directors Deferred Compensation Plan.

Non-Employee Directors Deferred Compensation Plan

Our general partner has adopted the Penn Virginia Resource GP, LLC Amended and Restated Non-Employee Directors Deferred Compensation Plan. This plan permits the non-employee directors of our general partner to defer the receipt of any or all cash, common units and restricted units they receive as compensation. All deferrals, and any distributions with respect to deferred common units or deferred restricted units, are credited to a deferred compensation account, the cash portion of which is credited quarterly with interest calculated at the prime rate. Non-employee directors of our general partner are fully vested at all times in any cash or deferred common units credited to their deferred compensation accounts. Any restricted unit awards credited to a deferred compensation account are subject to the same vesting and forfeiture restrictions that apply to the underlying award. Amounts held in a non-employee director's deferred compensation account will be distributed to the director on the January 1st following the earlier to occur of the director reaching age 70 or the resignation or removal of the director from the board of directors of our general partner. Upon the death of a non-employee director, all vested amounts held in the deferred compensation account of the non-employee director will be distributed to the director's estate.

Compensation Committee Interlocks and Insider Participation

During 2007, Messrs. Cloues, DesBarres, Gardner and Montague served on the compensation and benefits committee of our general partner. None of these members is a former or current officer or employee of us or any of our subsidiaries or had any relationship requiring disclosure under Item 404 of Regulation S-K, "Transactions with Related Persons, Promoters and Certain Control Persons." In 2007, none of the executive officers of our general partner served as a member of the board of directors or compensation committee of any entity that has one or more executive officers serving on the board of directors or the compensation and benefits committee of our general partner.

Compensation Committee Report

Under the rules established by the SEC, we are required to discuss the compensation and benefits of the executive officers of our general partner, including our CEO, our CFO and our other NEOs. The Compensation and Benefits Committee is furnishing the following report in fulfillment of the SEC's requirements.

The Compensation and Benefits Committee has reviewed the information contained above under the heading "Compensation Discussion and Analysis" and has discussed the Compensation Discussion and Analysis with management. Based upon its review and discussions with management, the Compensation and Benefits Committee recommended to the board of directors of the Partnership's general partner that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Compensation and Benefits Committee

James L. Gardner (Chairman)
Edward B. Cloues, II
John P. DesBarres
James R. Montague

Item 12 ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters***

Beneficial Ownership of Units

The following table sets forth, as of February 28, 2008, the amount and percentage of our outstanding common units beneficially owned by (i) each person known by us to own beneficially more than 5% of our common units, (ii) each director of our general partner, (iii) each executive officer of our general partner and (iv) all directors and executive officers of our general partner as a group:

Name of Beneficial Owner	Common Units (1)		Percent of Common Units (2)
Penn Virginia GP Holdings, L.P. (3)	19,587,049		42.5%
Penn Virginia Resource GP Corp. (3)	88,093		*
Edward B. Cloues, II	26,253	(4)	*
A. James Dearlove	97,905	(5)	*
John P. DesBarres	53,166	(6)	*
James L. Gardner	8,185	(7)	*
Keith D. Horton	68,008	(8)	*
James R. Montague	27,331	(9)	*
Ronald K. Page	33,414	(10)	*
Marsha R. Perelman	20,519	(11)	*
Frank A. Pici	40,093	(12)	*
Nancy M. Snyder	38,942	(13)	*
All directors and executive officers as a group (10 persons)	413,816	(14)	*

* Less than 1%.

(1) Unless otherwise indicated, all common units are owned directly by the named holder and such holder has sole power to vote and dispose of such units.

(2) Based on 46,106,285 common units issued and outstanding on February 28, 2008. On February 28, 2008, there were approximately 23,300 holders of our common units.

(3) Penn Virginia is the ultimate parent company of Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp. As such, Penn Virginia may be deemed to beneficially own the common units held by Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp., which together own 42.7% of our common units. The address for each of Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp. is c/o Penn Virginia Corporation, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087.

(4) Includes 12,331 deferred common units.

(5) Includes 42,275 restricted units.

(6) Includes 2,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan and 19,166 deferred common units.

(7) Reflects 8,185 deferred common units.

(8) Includes 29,687 restricted units and 1,000 common units held by Mr. Horton's spouse.

(9) Includes 2,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan and 12,331 deferred common units.

(10) Includes 27,010 restricted units.

(11) Includes 10,948 deferred common units and 5,000 common units held by a trust of which Ms. Perelman is a trustee and a beneficiary.

(12) Includes 15,089 restricted units.

(13) Includes 16,415 restricted units and 470 common units held by Ms. Snyder for the benefit of a minor child.

(14) Includes 130,476 restricted units, 4,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan, 62,961 deferred common units, 5,000 common units held by a trust of which Ms. Perelman is a trustee and a beneficiary, 1,000 common units held by Mr. Horton's spouse and 470 common units held by Ms. Snyder for the benefit of a minor child.

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2007 regarding the options outstanding and securities issued and to be issued under our general partner's equity compensation plans not approved by our unitholders. Our general partner does not have any equity compensation plans which were approved by our unitholders.

Plan Category	Number of Securities To Be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by unitholders	N/A	N/A	N/A
Equity compensation plans not approved by unitholders	0	N/A	156,721

Item 13 *Certain Relationships and Related Transactions, and Director Independence*

Transactions with Related Persons

Management and Administrative Services

We are managed and controlled by our general partner pursuant to our partnership agreement. Under our partnership agreement, our general partner is reimbursed for all direct and indirect expenses it incurs or payments it makes on our behalf. These expenses include salaries, fees and other compensation and benefit expenses of employees, officers and directors, insurance, other administrative or overhead expenses and all other expenses necessary or appropriate to conduct our business. The costs allocated to us by our general partner for administrative services and overhead totaled $4.6 million, $4.5 million and $2.6 million for the years ended December 31, 2007, 2006 and 2005.

Incentive Distributions

Our partnership agreement provides for incentive distributions payable to our general partner out of our Available Cash (as defined in our partnership agreement) in the event quarterly distributions to unitholders exceed certain specified targets. In general, subject to certain limitations, if a quarterly distribution exceeds a target of $0.275 per common unit, our general partner will receive incentive distributions equal to (i) 15% of that portion of the distribution per common unit which exceeds but is not more than $0.325, plus (ii) 25% of that portion of the quarterly distribution per common unit which exceeds $0.325 but is not more than $0.375, plus (iii) 50% of that portion of the quarterly distribution per common unit which exceeds $0.375. In 2007, our general partner received total distributions, including incentive distributions, of $45.6 million from us. See also Item 1, "Business—Partnership Distributions."

Units Purchase Agreement

In connection with the PVG IPO in December 2006, we entered into a Units Purchase Agreement with PVG. Pursuant to the Units Purchase Agreement, we sold an aggregate of 416,444 common units and 4,045,311 Class B units to PVG in three separate sales in December 2006 and January 2007. The total purchase price paid to us by PVG for the common and Class B units was $113.6 million.

Roaring Fork Royalty Interest Acquisition

In October 2007, we purchased from Penn Virginia Oil & Gas Corporation, a wholly-owned subsidiary of Penn Virginia, 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 our revolving credit facility.

Gas Gathering and Processing Agreement

Penn Virginia Oil & Gas, L.P., or PVOG, a wholly-owned subsidiary of Penn Virginia, and PVR East Texas Gas Processing LLC, or PVR East Texas, a wholly-owned subsidiary of us, are parties to a Gas Gathering and Processing Agreement effective April 1, 2007. Pursuant to the Gas Gathering and Processing Agreement, PVOG and PVR East Texas have agreed that PVR East Texas will gather and process all of PVOG's current and future gas production in certain areas of the Bethany Field in east Texas and redeliver the NGLs to PVOG for a $0.30/MMbtu service fee (with an annual CPI adjustment). The Gas Gathering and Processing Agreement has a primary term of 15 years and automatically renews for additional one year terms until terminated by either party. PVR East Texas will begin gathering and processing PVOG's gas upon completion of the new Crossroads System, which is expected to begin operations by April 2008.

Oil and Gas Marketing Agreement

PVOG and Connect Energy Services, LLC, or Connect Energy, a wholly-owned subsidiary of us, are parties to a Master Services Agreement effective September 1, 2006. Pursuant to the Master Services Agreement, PVOG and Connect Energy have agreed that Connect Energy will market all of PVOG's oil and gas production in Arkansas, Louisiana, Oklahoma and Texas for a fee equal to 1% of the net sales price (subject to specified limitations) received by PVOG for such production. The Master Services Agreement has a primary term of five years and automatically renews for additional one year terms until terminated by either party. In 2007, PVOG paid Connect Energy $2.2 million in fees pursuant to the Master Services Agreement.

Omnibus Agreement

Penn Virginia, us, our general partner and the Operating Company are parties to an Omnibus Agreement that governs potential competition among us. The Omnibus Agreement was entered into in connection with our initial public offering in October 2001. Upon completion of the PVG IPO, PVG became subject to the Omnibus Agreement as an affiliate of Penn Virginia. For purposes of the Omnibus Agreement, any restrictions that apply to Penn Virginia also apply to PVG.

Under the Omnibus Agreement, Penn Virginia and its affiliates are not permitted to engage in the businesses of: (i) owning, mining, processing, marketing or transporting coal, (ii) owning, acquiring or leasing coal reserves or (iii) growing, harvesting or selling timber, unless it or they first offers us the opportunity to acquire these businesses or assets and the board of directors of our general partner, with the concurrence of its conflicts committee, elects to cause us not to pursue such opportunity or acquisition. In addition, Penn Virginia and its affiliates will be able to purchase any business which includes the purchase of coal reserves, timber or infrastructure relating to the production or transportation of coal if the majority value of such business is not derived from owning, mining, processing, marketing or transporting coal or growing, harvesting or selling timber. If Penn Virginia or its affiliates make any such acquisition, it or they must offer us the opportunity to purchase the coal reserves, timber or related infrastructure following the acquisition and the conflicts committee of the board of directors of our general partner will determine whether we should pursue the opportunity. The restriction will terminate upon a change in control of Penn Virginia or our general partner.

Non-Compete Agreement

PVG and us are parties to a Non-Compete Agreement that governs potential competition among us. The Non-Compete Agreement was entered into in connection with the PVG IPO in December 2006, but is not effective until PVG is no longer subject to the Omnibus Agreement. Pursuant to the Non-Compete Agreement, PVG will have a right of first refusal with respect to the potential acquisition of any general partner interest, and any other equity interests under common ownership with such general partner, in a publicly traded partnership, other than any partnerships engaged in the coal or timber businesses described above or the business of gathering or processing natural gas or other hydrocarbons. We will have a right of first refusal with respect to the potential acquisition of assets that relate to the business of (i) owning, mining, processing, marketing or transporting coal, (ii) owning, acquiring or leasing coal reserves, (iii) growing, harvesting or selling timber or (iv) the gathering or processing of natural gas or other hydrocarbons.

Policies Regarding Transactions with Related Persons

Under our Corporate Governance Principles, all directors must recuse themselves from any decision affecting their personal, business or professional interests. In addition, as a general matter, our practice is that any proposed transaction between us (or any of our subsidiaries) and Penn Virginia or PVG (or any of their respective subsidiaries) is approved by the conflicts committee of our general partner. For a discussion of the conflicts committee of our general partner, see "Item 10—Directors, Executive Officers and Corporate Governance—Committees of the Board of Directors of our General Partner—Conflicts Committee." With respect to any proposed transaction with any other related person, as a general matter, our practice is that such transactions are approved by disinterested directors. The General Counsel of our general partner advises the board of directors of our general partner as to which transactions involve related persons, which transactions require the approval of the conflicts committee of our general partner and which directors are prohibited from voting on a particular transaction. All of the related transactions described above which were entered into since January 1, 2007 were approved in accordance with the foregoing policies.

Director Independence

Messrs. Cloues, DesBarres, Gardner and Montague and Ms. Perelman are "independent directors," as defined by NYSE Listing Standards and SEC rules and regulations. We refer to those directors as "Independent Directors." The board of directors of our general partner has determined that none of the Independent Directors have any relationship with us other than as a director of our general partner or its affiliates, Penn Virginia or PVG's general partner.

Item 14 *Principal Accounting Fees and Services*

In connection with the audits of our consolidated financial statements and our internal control over financial reporting, or ICFR, for 2007, we entered into an agreement with KPMG which sets forth the terms by which KPMG will perform audit services for us. That agreement is subject to alternative dispute resolution procedures, an exclusion of the right to collect punitive damages and various other provisions. The following table shows fees for professional audit services rendered by KPMG for the audits of our consolidated financial statements for 2007 and 2006 and the audits of our ICFR for 2007 and 2006 and fees billed for other services rendered by KPMG:

	2007	2006
Audit Fees (1)	$766,800	$696,100
Audit-Related Fees (2)	5,000	5,000
Tax Fees (3)	13,600	5,300
All Other Fees	—	—
Total Fees	$785,400	$706,400

(1) Audit fees consist of fees for the audit of our consolidated financial statements, the audit of our ICFR, consents for registration statements and comfort letters. Also included in audit fees are reimbursements of travel-related expenses.

(2) Audit-related fees consist of fees pertaining to debt compliance letters issued by KPMG for the Notes.

(3) Tax fees consist of fees for reviews of state tax returns for certain of our subsidiaries.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accountants

The policy of the audit committee of our general partner is to pre-approve all audit, audit-related and non-audit services provided by the independent registered public accountants. These services may include audit services, audit-related services, tax services and other services. The audit committee may also pre-approve particular services on a case-by-case basis. The independent registered public accountants are required to periodically report to the audit committee regarding the extent of services provided by the independent registered public accountants in accordance with such pre-approval. The audit committee may also delegate pre-approval authority to one or more of its members. Such member(s) must report any decisions to the audit committee at the next scheduled meeting.

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 59 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

(2.1) Purchase and Sale Agreement dated as of August 23, 2007 among Penn Virginia Operating Co., LLC and MeadWestvaco Corporation (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on September 24, 2007).

(3.1) Certificate of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.1 to Registrant's Registration Statement on Form S-1 filed on July 19, 2001).

(3.2) Second Amended and Restated Agreement of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on October 26, 2007).

(3.3) Certificate of Formation of Penn Virginia Operating Co., LLC (incorporated by reference to Exhibit 3.3 to Amendment No. 2 to Registrant's Registration Statement on Form S-1 filed on October 4, 2001).

(3.4) Form of Amended and Restated Limited Liability Company Agreement of Penn Virginia Operating Co., LLC (incorporated by reference to Exhibit 3.4 to Amendment No. 3 to Registrant's Registration Statement on Form S-1 filed on October 16, 2001).

(3.5) Certificate of Formation of Penn Virginia Resource GP, LLC (incorporated by reference to Exhibit 3.5 to Amendment No. 1 to Registrant's Registration Statement Form S-1 filed on September 7, 2001).

(3.6) Fourth Amended and Restated Limited Liability Company Agreement of Penn Virginia Resource GP, LLC (incorporated by reference to Exhibit 3.2 to Registrant's Current Report on Form 8-K filed on December 13, 2006).

(4.1) Note Purchase Agreement dated as of March 27, 2003 among Penn Virginia Operating Co., LLC, Penn Virginia Resource Partners, L.P. and the noteholders party thereto (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on April 2, 2003).

(4.2) First Amendment to Note Purchase Agreement and Parent Guaranty dated as of March 3, 2005 among Penn Virginia Operating Co., LLC, Penn Virginia Resource Partners, L.P. and the noteholders party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 9, 2005).

(4.3) Second Amendment to Note Purchase Agreement dated as of December 11, 2006 among Penn Virginia Operating Co., LLC, Penn Virginia Resource Partners, L.P. and the noteholders party thereto (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on December 13, 2006).

(4.4) Third Amendment to Note Purchase Agreement and Parent Guaranty dated as of September 19, 2007 among Penn Virginia Operating Co., LLC, Penn Virginia Resource Partners, L.P. and the noteholders party thereto (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on September 20, 2007).

(10.1) Amended and Restated Credit Agreement dated as of March 3, 2005 among Penn Virginia Operating Co., LLC, the guarantors party thereto, PNC Bank, National Association, as agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on March 9, 2005).

(10.2) First Amendment, Waiver, and Consent to Amended and Restated Credit Agreement dated as of July 15, 2005 among Penn Virginia Operating Co., LLC, the guarantors party thereto, PNC Bank, National Association, as agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on July 21, 2005).

(10.3) Second Amendment to Amended and Restated Credit Agreement dated as of August 22, 2006 among Penn Virginia Operating Co., LLC, the guarantors party thereto, PNC Bank, National Association, as agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006).

(10.4) Third Amendment to Amended and Restated Credit Agreement dated as of December 11, 2006 among Penn Virginia Operating Co., LLC, the guarantors party thereto, PNC Bank, National Association, as agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 13, 2006).

(10.5) Fourth Amendment to Amended and Restated Credit Agreement dated as of September 7, 2007 among Penn Virginia Operating Co., LLC, the guarantors party thereto, PNC Bank, National Association, as agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on September 7, 2007).

(10.6) Fifth Amendment to Amended and Restated Credit Agreement dated as of October 8, 2007 among Penn Virginia Operating Co., LLC, the guarantors party thereto, PNC Bank, National Association, as agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 10, 2007).

(10.7) Contribution and Conveyance Agreement dated September 13, 2001 among Penn Virginia Operating Co., LLC, Penn Virginia Holding Corp., Penn Virginia Resource Holdings Corp., Penn Virginia Resource LP Corp., Penn Virginia Resource GP Corp. and the other parties named therein (incorporated by reference to Exhibit 10.2 to Amendment No. 2 to Registrant's Registration Statement on Form S-1 filed on October 4, 2001).

(10.8) Contribution, Conveyance and Assumption Agreement dated September 14, 2001 among Penn Virginia Resource GP, LLC, Penn Virginia Resource Partners, L.P., Penn Virginia Operating Co., LLC and the other parties named therein (incorporated by reference to Exhibit 10.3 to Amendment No. 2 to Registrant's Registration Statement on Form S-1 filed on October 4, 2001).

(10.9) Closing Contribution, Conveyance and Assumption Agreement dated October 30, 2001 among Penn Virginia Operating Co., LLC, Penn Virginia Corporation, Penn Virginia Resource Partners, L.P., Penn Virginia Resource GP, LLC, Penn Virginia Resource L.P. Corp., Wise LLC, Loadout LLC, PVR Concord LLC, PVR Lexington LLC, PVR Savannah LLC, Kanawha Rail Corp. (incorporated by reference to Exhibit 10.7 to Amendment No. 2 to Registrant's Registration Statement on Form S-1 filed on October 4, 2001).

(10.10) Omnibus Agreement dated October 30, 2001 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 10.6 to Amendment No. 2 to Registrant's Registration Statement on Form S-1 filed on October 4, 2001).

(10.11) 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 10.7 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(10.12) Non-Compete Agreement dated December 8, 2006 among Penn Virginia GP Holdings, L.P., Penn Virginia Resource Partners, L.P. and Penn Virginia Resource GP, LLC (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 13, 2006).

(10.13) Penn Virginia Resource GP, LLC Third Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*

(10.14) Form of Agreement for Deferred Common Unit Grants under the Penn Virginia Resource GP, LLC Third Amended and Restated Long-Term Incentive Plan.*

(10.15) Form of Agreement for Restricted Unit Awards under the Penn Virginia Resource GP, LLC Third Amended and Restated Long-Term Incentive Plan.*

(10.16) Penn Virginia Resource GP, LLC Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*

(10.17) 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).*

(10.18) 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 Resource Partners, L.P.

(23.1) Consent of KPMG LLP.

(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.

---

* 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 RESOURCE PARTNERS, L.P.

By: PENN VIRGINIA RESOURCE GP, LLC

February 28, 2008

By: /s/ FRANK A. PICI
Frank A. Pici
Vice President and Chief Financial Officer

February 28, 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/ A. JAMES DEARLOVE **A. James Dearlove**	Chairman of the Board and Chief Executive Officer	February 28, 2008
/s/ EDWARD B. CLOUES, II **Edward B. Cloues, II**	Director	February 28, 2008
/s/ JOHN P. DESBARRES **John P. DesBarres**	Director	February 28, 2008
/s/ JAMES L. GARDNER **James L. Gardner**	Director	February 28, 2008
/s/ JAMES R. MONTAGUE **James R. Montague**	Director	February 28, 2008
/s/ MARSHA R. PERELMAN **Marsha R. Perelman**	Director	February 28, 2008
/s/ FRANK A. PICI **Frank A. Pici**	Director and Vice President and Chief Financial Officer	February 28, 2008
/s/ NANCY M. SNYDER **Nancy M. Snyder**	Director and Vice President and General Counsel	February 28, 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, Chief Executive Officer of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P. (the "Registrant"), certify that:

1. I have reviewed this 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 board of directors of the general partner of the Registrant:

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

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

Date: February 28, 2008

/s/ A. JAMES DEARLOVE

A. James Dearlove
Chief Executive Officer

Exhibit 31.2

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

I, Frank A. Pici, Vice President and Chief Financial Officer of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P. (the "Registrant"), certify that:

1. I have reviewed this 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 board of directors of the general partner of the Registrant:

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

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

Date: February 28, 2008

/s/ FRANK A. PICI

Frank A. Pici
Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Penn Virginia Resource Partners, L.P. (the "Partnership") 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, Chief Executive Officer of Penn Virginia Resource GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: February 28, 2008

/s/ A. JAMES DEARLOVE

A. James Dearlove
Chief Executive Officer

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

Exhibit 32.2

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

In connection with the Annual Report of Penn Virginia Resource Partners, L.P. (the "Partnership") 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, Vice President and Chief Financial Officer of Penn Virginia Resource GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: February 28, 2008

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

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

Partnership Information

DIRECTORS*

A. James Dearlove
Chairman of the Board and Chief Executive Officer; Director, President and Chief Executive Officer of Penn Virginia Corporation; Chairman of the Board, President and Chief Executive Officer of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P.

Edward B. Cloues, II[2]
Chairman and Chief Executive Officer of K-Tron International, Inc.; Director of Penn Virginia Corporation

John P. DesBarres[1,2,3]
Former Chairman, President and Chief Executive Officer of Transco Energy Company, Inc.

James L. Gardner[1,2,3]
Associate Professor, Freed-Hardeman University and Former Executive Vice President, Chief Administrative Officer and General Counsel of Massey Energy Company

James R. Montague[1,2,3]
Former President of Encana Gulf of Mexico, LLC and former President of IP Petroleum Company and GCO Minerals Company (subsidiaries of International Paper Co.)

Marsha Reines Perelman
Founder and Chief Executive Officer of Woodforde Management, Inc.; Director of Penn Virginia Corporation

Frank A. Pici
Vice President and Chief Financial Officer; Executive Vice President and Chief Financial Officer of Penn Virginia Corporation; Director, Vice President and Chief Financial Officer of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P.

Nancy M. Snyder
Vice President and General Counsel; Executive Vice President, General Counsel and Corporate Secretary of Penn Virginia Corporation; Director, Vice President and General Counsel of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P.

MANAGEMENT*

A. James Dearlove
Chief Executive Officer

Keith D. Horton
Co-President and Chief Operating Officer—Coal

Ronald K. Page
Co-President and Chief Operating Officer—Midstream

Frank A. Pici
Vice President and Chief Financial Officer

Nancy M. Snyder
Vice President and General Counsel

Forrest W. McNair
Vice President and Controller

Steven A. Hartman
Vice President and Treasurer

Patrick J. Udovich
Vice President, Human Resources

James F. Modzelewski
Vice President and Assistant General Counsel

Jean M. Whitehead
Secretary

TRANSFER AGENT AND REGISTRAR

American Stock Transfer and Trust Company
Mailing Address:
59 Maiden Lane
New York, NY 10038
(800) 937-5449 phone
(718) 236-2641 fax

CERTIFICATIONS

In 2007, PVR submitted our Section 303A.12(a) chief executive officer certification to the New York Stock Exchange. We have also filed with the Securities and Exchange Commission, as an exhibit to our most recently filed Annual Report on Form 10-K, the Sarbanes-Oxley Act Section 302 certifications.

PENN VIRGINIA RESOURCE PARTNERS, L.P.
Three Radnor Corporate Center, Suite 300
100 Matsonford Road, Radnor, PA 19087
610.687.8900 phone 610.687.3688 fax
www.pvresource.com

This is a green ANNUAL REPORT™
www.GreenAnnualReport.com

Penn Virginia Resource Partners, L.P. saved the following resources by producing this Green Annual Report™

16.26 trees preserved for the future

46.96 lbs water-borne waste not created

6,906 gals wastewater flow saved

764 lbs solid waste not generated

1,505 lbs net greenhouse gases prevented

11,517,500 million BTUs energy not consumed

END