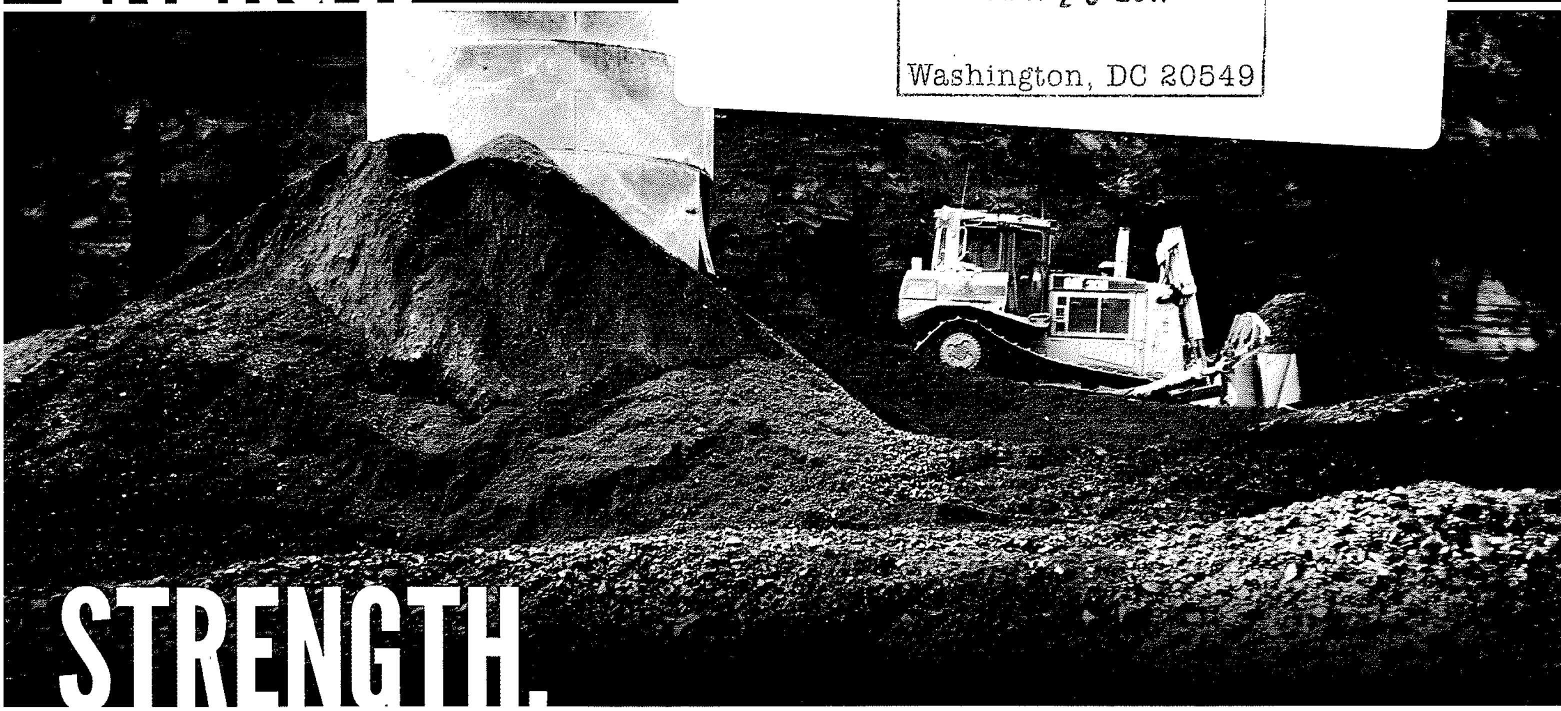
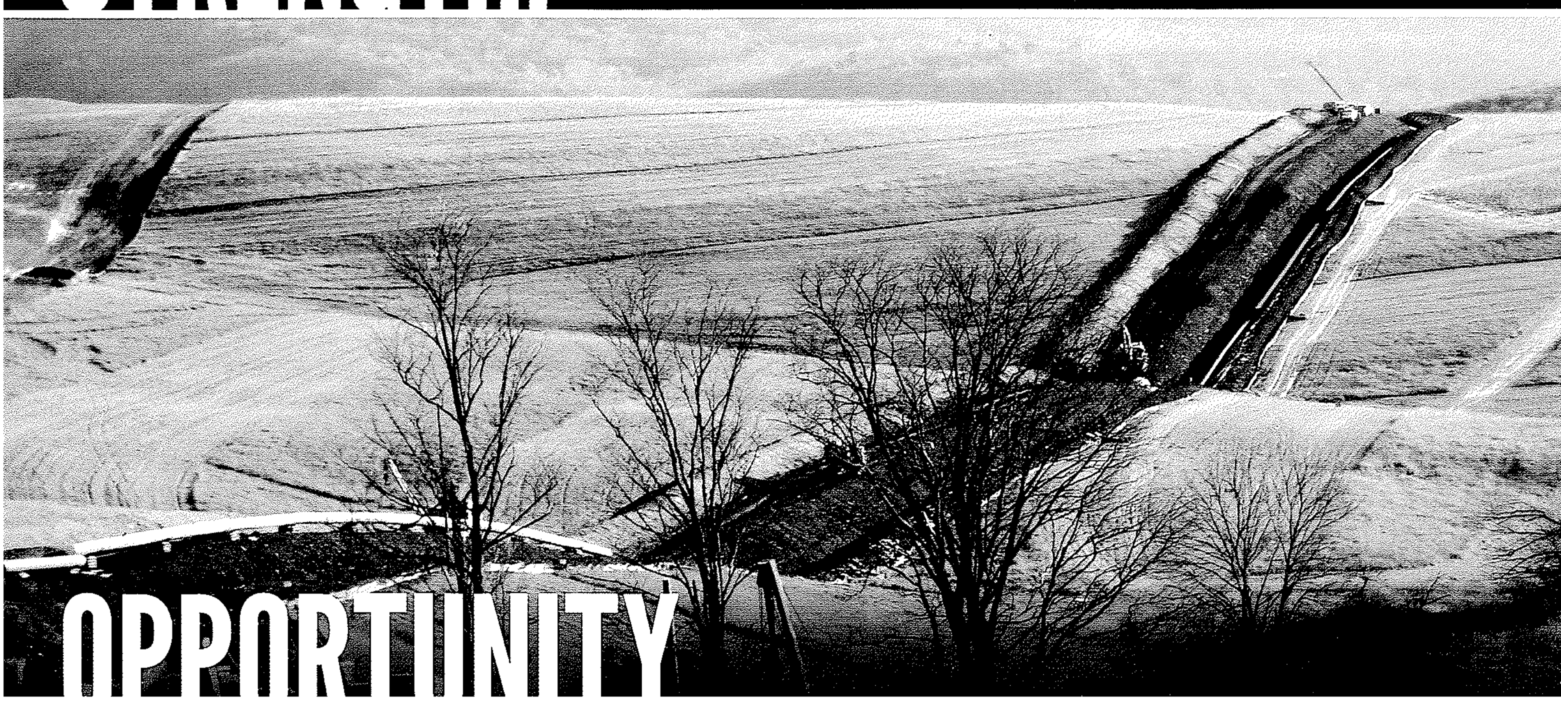
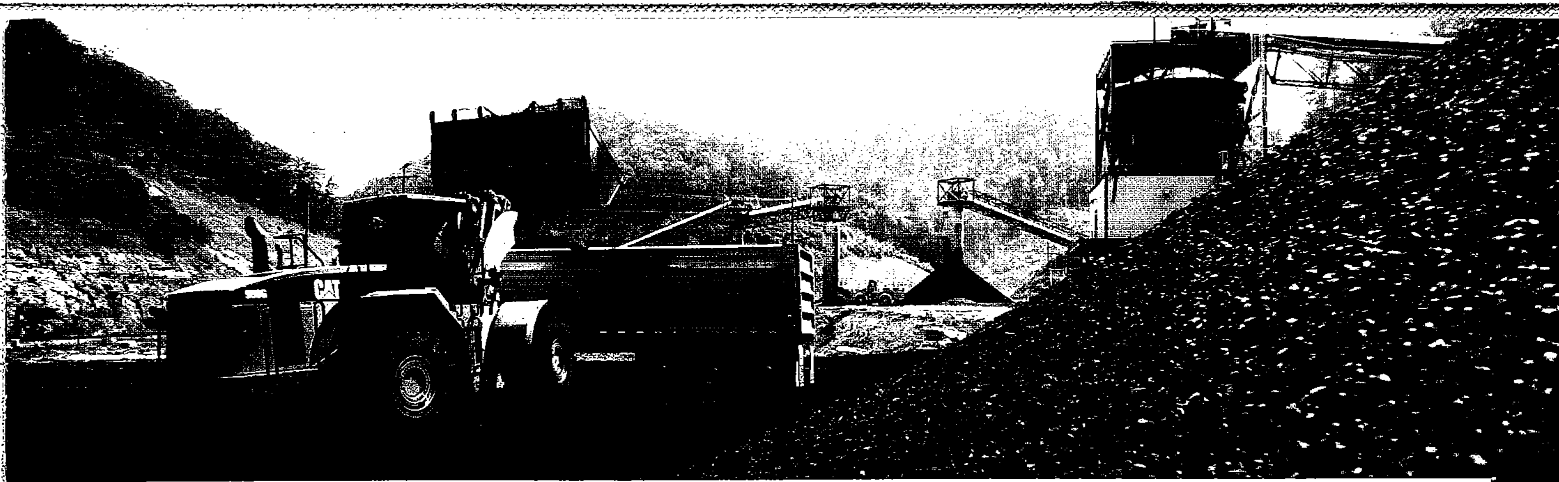
PVR PARTNERS







Penn Virginia Resource Partners, L.P. (NYSE: PVR) is a publicly traded limited partnership which owns and manages coal and natural resource properties and related assets, and owns and operates midstream natural gas gathering and processing businesses. We own more than 800 million tons of proven coal reserves in Northern and Central Appalachia, and the Illinois and San Juan Basins; our midstream natural gas assets are located principally in Texas, Oklahoma and Pennsylvania and include more than 4,200 miles of natural gas gathering pipelines and 6 processing systems with approximately 400 million cubic feet per day of capacity.

COAL & NATURAL RESOURCE MANAGEMENT

PVR Coal and Natural Resource Management oversees coal and natural resource properties, provides fee-based coal preparation and loading services, sells timber, collects oil and gas royalties, and collects fees from the transportation of coal. We own a diversified portfolio of strategically located coal reserves and related assets that generate consistent operating cash flows.

NATURAL GAS MIDSTREAM

PVR Midstream owns and operates natural gas gathering, processing and other related assets in Texas, Oklahoma and Pennsylvania, and owns a 25% interest in a major gathering system in Wyoming. Our midstream assets have demonstrated consistent annual volume growth, and are well positioned to benefit from increasing activity in emerging resource plays in the Granite Wash, Marcellus Shale, Haynesville Shale and Horizontal Cotton Valley formations. PVR Midstream's cash flow is derived from both fee-based and commodity-sensitive commercial arrangements. PVR mitigates a portion of its commodity price risk on price-sensitive volumes through utilization of commodity price hedges.

FINANCIAL DISCIPLINE

PVR is fiscally conservative, maintaining both a strong balance sheet and solid distribution coverage. We have funded steady growth through a combination of debt and new unit issuances. PVR continues to seek growth opportunities through both organic projects and strategic acquisitions that provide for increases in sustainable distributable cash flow at attractive rates of return for unitholders.

2010 ASSET LOCATIONS AND OPERATING STATISTICS

COAL AND NATURAL RESOURCE LOCATIONS

34.5 MILLION TONS
2010 Lease Production

803.7 MILLION TONS
Proven / Probable Reserves

23.3 YEARS
R/P Ratio

Region	2010 Lease Production (Million tons)	Proven/ Probable Reserves (Million tons)	R/P Ratio (Years)
1 Northern Appalachia	4.0	29.7	7.4
2 Central Appalachia	18.2	583.5	32.1
3 Illinois Basin	4.2	161.2	38.4
4 San Juan Basin	8.1	29.3	3.6

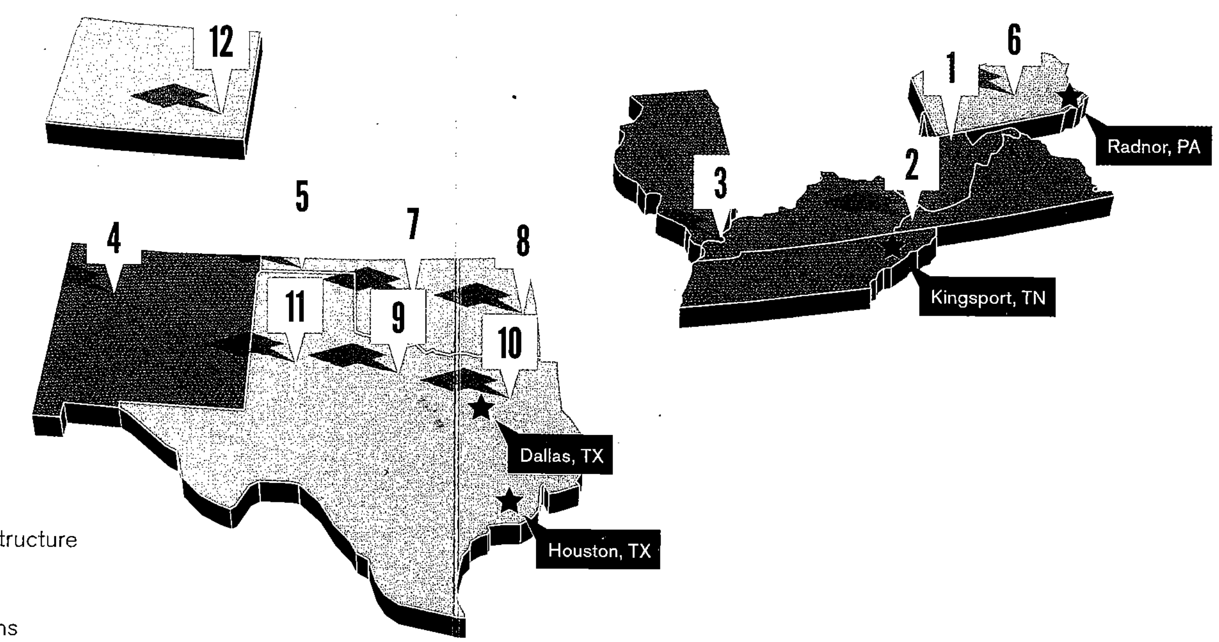
NATURAL GAS MIDSTREAM LOCATIONS

4,263 MILES
Gathering Pipeline

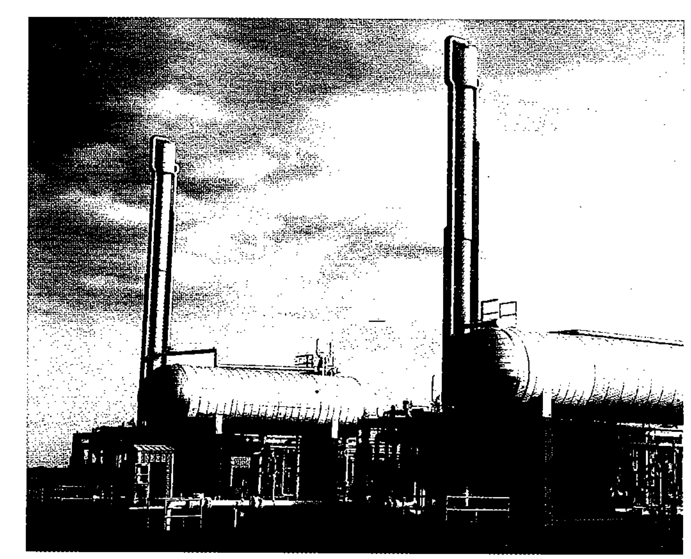
400 MILLION cfd
Natural Gas Processing Capacity

355 MILLION cfd
Average System Throughput Volume

System	Gathering Pipeline (Miles)	Processing Capacity (Million cfd)	2010 Volume (Million cfd)
5 Panhandle	1,817	260	222
6 Marcellus	3	–	10
7 Crescent	1,705	40	22
8 Arkoma	78	–	11
9 North Texas	136	–	16
10 Crossroads	8	80	67
11 Hamlin	517	20	8
12 Thunder Creek (25% JV)	535	–	373



■ Coal Reserves and Infrastructure
■ Natural Gas Midstream
★ Principal Office Locations

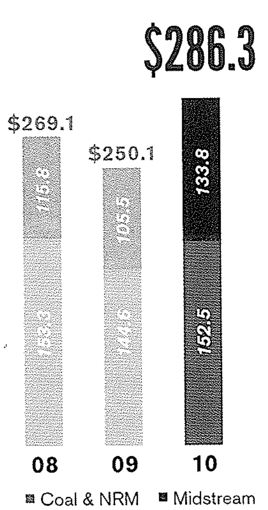


FINANCIAL AND OPERATING HIGHLIGHTS 2010

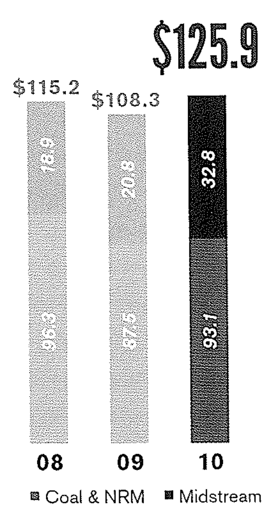
	2010	2009	2008	2007	2006
Financial Data *(in Millions)*					
Net revenues[1]	**$ 286.3**	$ 250.1	$ 269.1	$ 206.2	$ 183.3
Operating income	**125.9**	108.3	115.2	117.7	102.8
Net income	**68.5**	65.2	104.5	56.6	73.9
Cash flow from operations	**183.7**	160.0	139.2	127.8	107.3
Distributable cash flow[2]	**145.8**	151.7	129.9	120.5	101.6
Total assets	**1,297.5**	1,208.1	1,218.8	931.3	714.0
Long-term debt, excluding current portion	**708.0**	620.1	568.1	399.2	207.2
Partners' capital	**428.5**	476.5	530.7	371.3	402.2
Long-term debt as percent of total capitalization	**62%**	57%	52%	52%	34%
Per Limited Partner Unit Data[3]					
Net income[4]	**$ 0.83**	$ 0.76	$ 1.63	$ 0.92	$ 1.59
Cash distributions paid	**1.88**	1.88	1.82	1.66	1.48
Weighted average number of limited partner units outstanding	**52.1**	51.8	49.5	46.1	42.0
Operating Data					
Coal produced by lessees (millions of tons)	**34.5**	34.3	33.7	32.5	32.8
Coal royalties ($/ton)	**$ 3.78**	$ 3.51	$ 3.65	$ 2.89	$ 2.99
Estimated coal reserves (millions of recoverable tons)	**804**	829	827	818	765
Natural gas system volumes (MMcfd)	**355**	332	270	186	170

(1) 2010-2006 amounts are shown net of cost of gas purchased of $578 million, $407 million, $613 million, $343 million and $335 million, respectively.
(2) Distributable cash flow is a non-GAAP measure; see page nine for definition and reconciliation to net income.
(3) Per unit data reflects two-for-one unit split in April 2006.
(4) Per unit amount is computed after general partner's share.

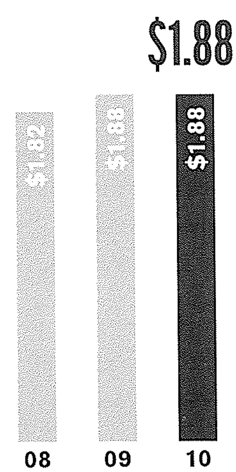
Net Revenues
in Millions



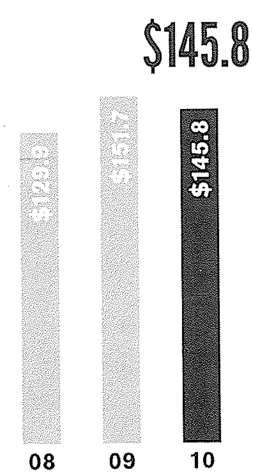
Operating Income
in Millions



Cash Distributions Paid
per LP unit



Distributable Cash Flow[2]
in Millions



TO OUR UNITHOLDERS

William H. Shea, Jr. | Chief Executive Officer

ENERGY. STRENGTH. OPPORTUNITY.

These words aptly summarize Penn Virginia Resource Partners. They convey PVR's key attributes to investors, customers, business partners, vendors, employees and all stakeholders having an interest in us. They communicate the essence of the businesses we operate, the assets we own, the way we approach our work and our perspective on the future. They also appropriately reflect our accomplishments during 2010.

Energy.

We are pleased to report another year of growth and strong operating results for our energy businesses during 2010. Despite last year's uncertain economy and volatile commodity prices, PVR achieved new records in key business metrics for both our coal and natural resource management and our natural gas midstream operating segments. Coal production by lessees increased to a record 34.5 million tons, and average coal royalties per ton increased to $3.78, resulting in an eight percent increase in coal royalties revenues. Natural gas throughput volumes increased seven percent to an average 355 million cubic feet per day during 2010. Operating income for 2010 rose by $17.6 million or 16% to a record $125.9 million.

Our strong 2010 operating performance drove strong bottom line results. Total net income grew by five percent to $68.5 million, and net income per limited partner unit increased by nine percent to $0.83.

Strength.

Our partnership marked a major milestone in 2010 as PVR became a fully independent organization with a strong new senior executive team dedicated solely to its performance and success. Informed of Penn Virginia Corporation's ("PVA") intention to divest its remaining ownership interest in our general partner, and convinced that PVR would benefit significantly from more highly focused management attention, the PVR Board asked me to take the helm as Chief Executive Officer in March. Rob Wallace joined us as Chief Financial Officer later the same month. In June, Bruce Davis came on board, assuming responsibility as General Counsel. Because PVR had shared not only PVA management, but also their administrative systems and certain administrative personnel, the separation from PVA required that we also establish independent information systems and support functions. I am pleased to report that we have successfully completed a full transition from PVA support. We have assembled a highly qualified team of experienced individuals to run and support our business, and have fully completed a successful implementation of our own independent accounting, information and other administrative support systems. It is especially gratifying to note this major effort was accomplished without disruption to our ongoing business operations, and I commend our PVR employees, who devoted many long hours to this task, for their expertise, energy and dedication. In particular, I would like to recognize the critical contributions of Keith Horton, president of our coal and natural resource business segment, Ron Page, president of our natural gas midstream segment, and Forrest McNair, our controller; the smooth separation from PVA would not have been possible without their continuing strong leadership at PVR.

PVR moved forward during 2010 in strengthening our balance sheet and positioning the Partnership with additional capacity to finance growth opportunities. In April we successfully completed a $300 million offering of senior notes, using the proceeds to pay down outstanding balances on our revolving credit facility. During the summer, we renegotiated our credit facility, expanding our credit line to $850 million and extending the term to five years. These crucial steps significantly improved our ability to fund our continued growth through internal expansion work, organic growth projects and strategic acquisitions.

In September we announced the agreement to simplify our capital structure by acquiring Penn Virginia GP Holdings ("PVG"), the owner of our general partner. The resulting merger of PVG into PVR, completed on March 10, 2011, further strengthens PVR's competitive position by lowering our cost of equity, which in turn enhances the potential cash accretion from acquisitions and internal growth projects. The merger strengthens corporate governance as PVR investors have now gained the right to elect all of the directors on our Board. The simplified organizational structure and improved transparency resulting from the merger gives PVR a stronger market profile. PVR investors should also benefit from the increased public float and trading liquidity in the market for PVR's units as a result of the merger.

Opportunity.

Our most visible and exciting growth project during 2010 was the new natural gas midstream gathering business we began in the north-central region of the Pennsylvania Marcellus Shale. In March we announced two separate compression and gathering agreements with key Marcellus Shale gas producers. We completed construction and started operation of our Wyoming County area system in June. Construction of our Lycoming system began in September, and the first phase of that pipeline is now completed and began flowing gas in February 2011. Together these two new gathering systems provide capacity to handle more than 900 million cubic feet of natural gas per day. We are currently working to extend and expand both systems to provide service to additional producers in proximity to these operations and anticipate a finished network with nearly 50 miles of trunk lines and over 100 miles of local gathering lines.

We also continued adding to our portfolio of coal reserves last year. In June we acquired approximately 10 million tons of Pittsburgh Seam coal reserves in Northern Appalachia. In December we announced the acquisition of over 100 million tons of coal reserves and resources in Central Appalachia. With the completion of these two important additions to our natural resource assets, our coal reserves are sufficient to sustain continued production at the current rate for approximately another 25 years.

The stock market has recognized the opportunity and strength in PVR's energy businesses. Our unit price increased 31.4% last year; this price appreciation combined with the cash distributions paid during the year produced a total 2010 return to PVR investors of 40.1% as compared to the 12.8% gain in the S&P 500 Index and a 35.9% increase in the Alerian MLP Total Return Index. PVR's long-term record is also impressive; investors who purchased units at PVR's October 2001 initial public offering have enjoyed a cumulative total return of 297.7% as of December 31st last year as compared with a 15.9% return in the S&P 500 Index and a 273.8% return in the Alerian MLP Total Return Index.

Thank you for your investment in PVR and for the confidence you have placed in us. Our complete financial report on SEC Form 10-K is enclosed, and we encourage you to read it for more information about PVR's business and 2010 financial results.

Sincerely,

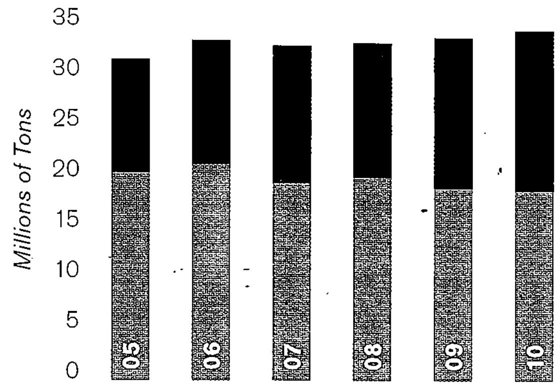
Will H Shea Jr

William H. Shea, Jr.
Chief Executive Officer

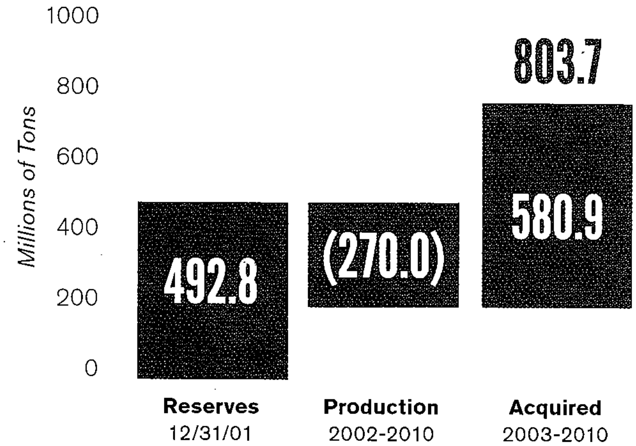
COAL AND NATURAL RESOURCE MANAGEMENT 2010

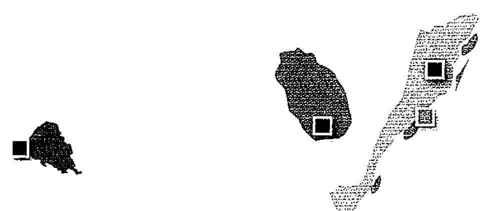
■ San Juan Basin ■ Northern Appalachia ▨ Central Appalachia ■ Illinois Basin

Coal Production



Changes in Coal Reserves: 2002-2010





SAN JUAN BASIN

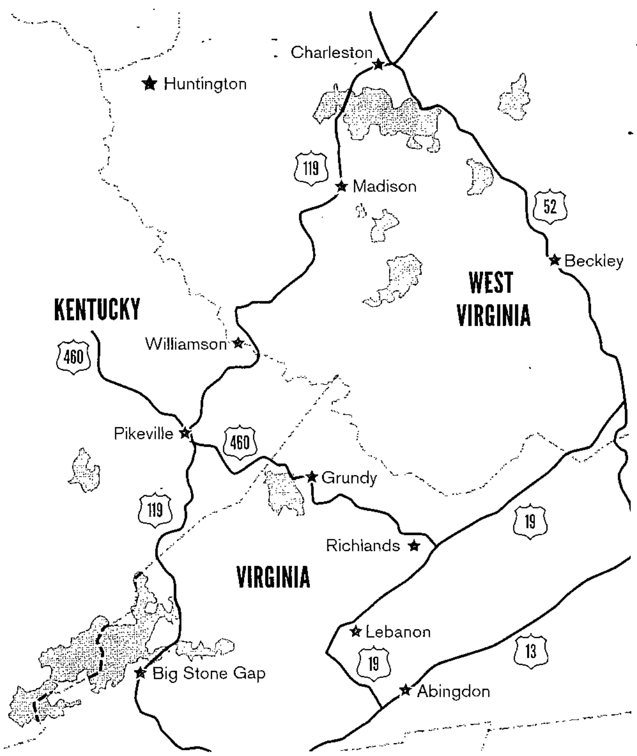
29 MILLION tons of Coal Reserves

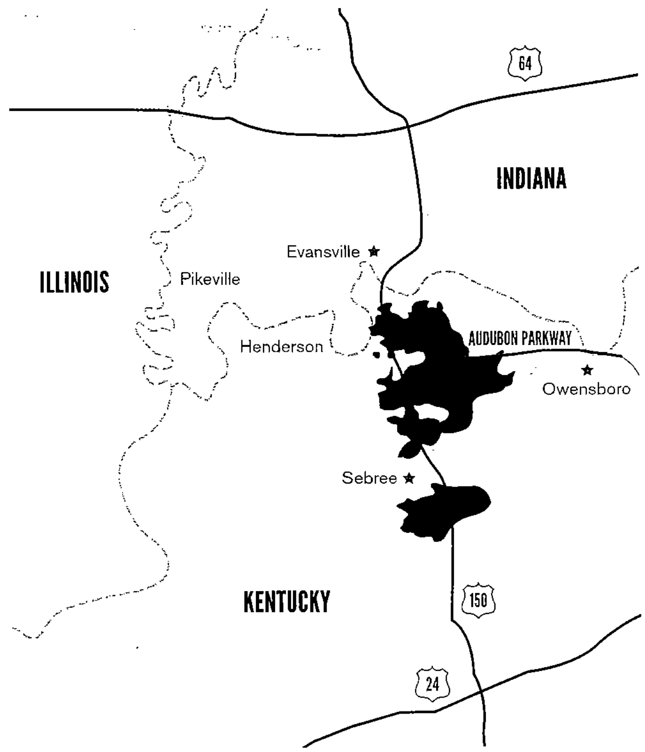
Properties located in northwestern New Mexico with 29.3 million tons, or four percent, of our reserves. The surface reserves are predominantly low to medium sulfur, low-BTU content steam coal. Approximately 8.1 million tons, or 23.6 percent, of lessee production in 2010 was from this region at an average royalty rate of $2.19 per ton.

NORTHERN APPALACHIA

30 MILLION tons of Coal Reserves

Properties located in northern West Virginia with 29.7 million tons, or four percent, of our reserves. The underground reserves consist of high sulfur, high-BTU content steam coal located on two properties. Approximately 4.0 million tons, or 11.5 percent, of lessee production in 2010 was from this region at an average royalty rate of $2.13 per ton.





CENTRAL APPALACHIA

584 MILLION tons of Coal Reserves

Properties located in eastern Kentucky, southwestern Virginia and southern West Virginia with 583.5 million tons, or 72 percent, of our reserves. The reserves are predominantly low to medium sulfur, high-BTU content steam coal. Approximately 18.2 million tons, or 52.8 percent, of lessee production in 2010 was from this region at an average royalty rate of $5.10 per ton. In January 2011 we completed the acquisition of an additional 102 million tons of coal reserves and resources in Kentucky and Tennessee.

ILLINOIS BASIN

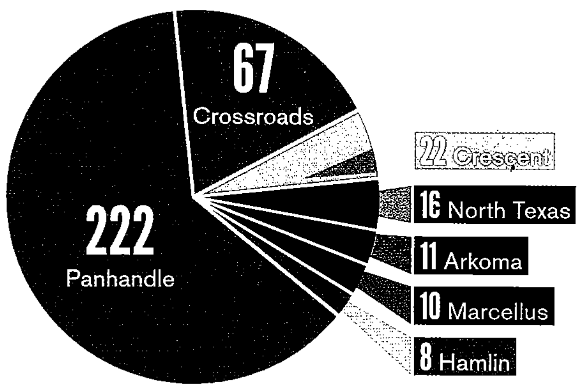
161 MILLION tons of Coal Reserves

Properties located in southern Illinois and western Kentucky with 161.2 million tons, or 20 percent, of our reserves. The reserves are predominantly high sulfur, medium-BTU content steam coal. Approximately 4.2 million tons, or 12.1 percent, of lessee production in 2010 was from this region at an average royalty rate of $2.68 per ton.

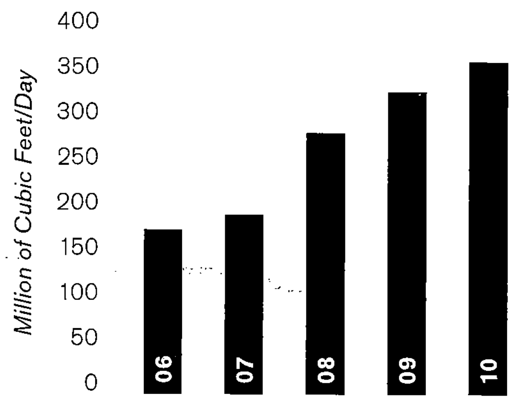
NATURAL GAS MIDSTREAM 2010

Thunder Creek ■ Marcellus Systems ■ Panhandle Systems □ Crescent ■ Crossroads ■ North Texas ■ Hamlin ■ Arkoma

Midstream Volumes by System *(MMcfd)*



Volumes



THUNDER CREEK [1]

373 MMcfd System Throughput Volume

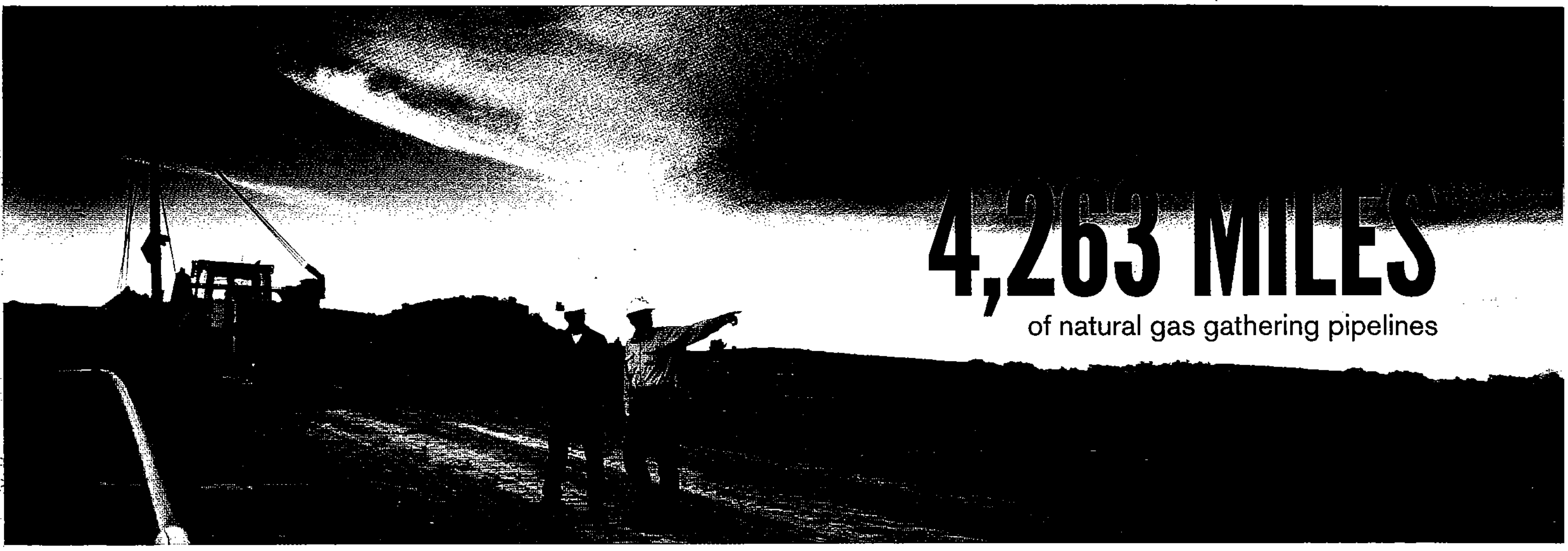
The Thunder Creek System is a coalbed methane gathering and transportation system with approximately 535 miles of pipeline in the Powder River Basin of Wyoming. We own a 25% joint interest; Devon Energy is the system operator and owner of the remaining joint interest stake.

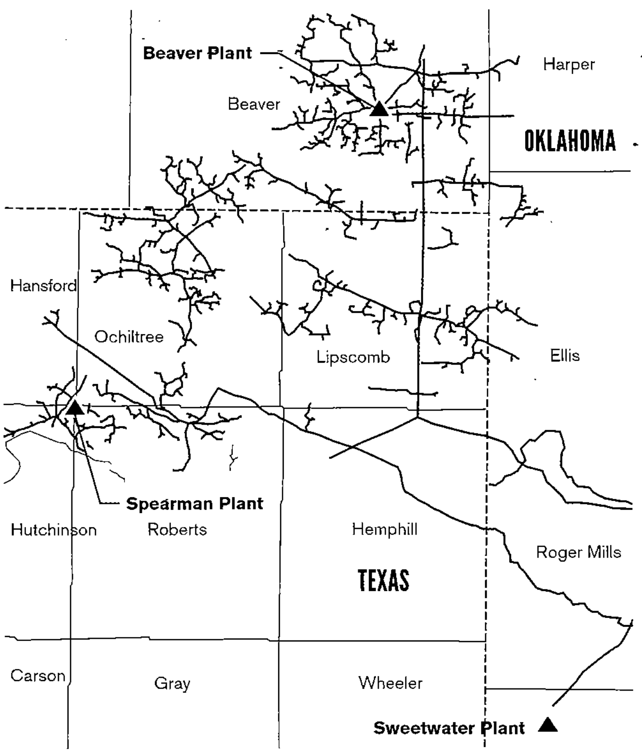
(1) Thunder Creek volumes not included in volume graphs or statistics

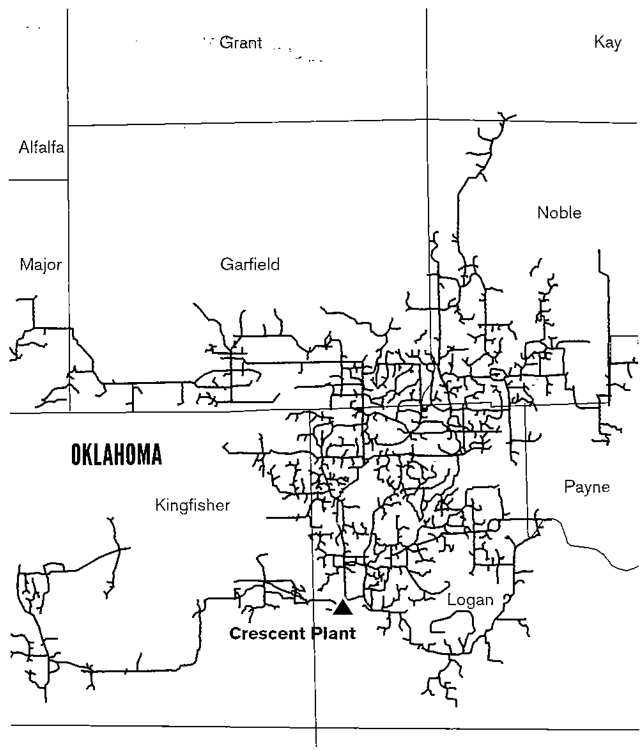
MARCELLUS SYSTEMS

10 MMcfd System Throughput Volume

The Marcellus Systems are located in Wyoming and Lycoming Counties in the north-central Pennsylvania region of the Marcellus Shale. The Wyoming system began service in June 2010 with 3 miles of pipeline. The Lycoming system, which began service in February 2011, features a 30-inch diameter mainline gathering trunkline with approximately 850 MMcfd of capacity. Construction and development of both systems continue, and we expect to invest approximately $120 million in these systems during 2011.







PANHANDLE SYSTEMS

222 MMcfd System Throughput Volume

The Panhandle Systems stretch across ten counties in the Anadarko Basin in the panhandle of Texas and western Oklahoma. The systems are comprised of approximately 1,817 miles of gathering pipelines and 30 compressor stations that gather gas to our processing plants at Beaver (100 MMcfd capacity), Spearman (100 MMcfd capacity) and Sweetwater (60 MMcfd capacity).

CRESCENT SYSTEM

22 MMcfd System Throughput Volume

The Crescent System services producers in seven counties within central Oklahoma's Sooner Trend. The system consists of approximately 1,705 miles of gathering pipelines and 14 compressor stations that deliver gas to our Crescent plant. The Crescent plant has 40 MMcfd of capacity and features a gas-engine generator that produces its own electric power for routine operation.

CROSSROADS SYSTEM

67 MMcfd System Throughput Volume

The Crossroads System is located in Harrison County and serves producers in the Haynesville Shale play in east Texas. The system's approximately 8 miles of pipelines gather gas to our Crossroads plant, which has 80 MMcfd of capacity.

NORTH TEXAS SYSTEM

16 MMcfd System Throughput Volume

The North Texas System is located in the southern portion of Fort Worth Basin, which includes the developing Barnett Shale play. The system includes approximately 136 miles of gathering pipelines serving 240,000 dedicated acres across six counties in North Texas.

HAMLIN SYSTEM

8 MMcfd System Throughput Volume

The Hamlin System consists of approximately 517 miles of gathering pipelines stretching over eight counties in the west-central area of Texas. The system has eight compressor stations, and brings volumes to our Hamlin plant that offers 20 MMfcd of capacity.

Reconciliation of Distributable Cash Flow to Net Income

(Amounts in Millions)	Year Ended December 31,				
	2010	2009	2008	2007	2006
Net Income	$ 68.5	$ 65.2	$ 104.5	$ 56.6	$ 73.9
DD&A	75.9	70.2	58.2	41.5	37.5
Impairments	-	1.5	31.8	-	-
Total derivative losses (gains)	23.6	22.7	(11.4)	50.2	13.2
Cash settlements of derivatives	(10.1)	3.0	(38.5)	(17.8)	(19.4)
Equity earnings from JV's, net of distributions	3.3	(2.5)	(0.2)	(0.3)	1.3
Other	-	-	-	-	4.6
Maintenance CAPEX	(15.3)	(8.4)	(14.5)	(9.8)	(9.5)
Distributable Cash Flow As Reported	$ 145.8	$ 151.7	$ 129.9	$ 120.5	$ 101.6

Distributable cash flow represents net income plus depreciation, depletion and amortization expenses, plus impairments, plus (minus) derivative losses (gains) included in other income, plus (minus) cash received (paid) for derivative settlements, minus equity earnings in joint ventures, plus cash distributions from joint ventures, minus maintenance capital expenditures. Distributable cash flow is a significant liquidity metric which is an indicator of our ability to generate cash flows at a level that can sustain or support an increase in quarterly cash distributions paid to our partners. Distributable cash flow is also the quantitative standard used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of publicly traded partnerships. Distributable cash flow is presented because we believe it is a useful adjunct to net cash provided by operating activities under GAAP. Distributable cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities, as an indicator of cash flows, as a measure of liquidity or as an alternative to net income.

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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, 2010

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)

Five Radnor Corporate Center, Suite 500
100 Matsonford Road
Radnor, Pennsylvania 19087
(Address of principal executive offices)

Registrant's telephone number, including area code: (610) 975-8200

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. 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 ("Exchange Act"). 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 $679,323,035 as of June 30, 2010 (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 22, 2011, 52,293,381 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

Forward-Looking Statements

Certain statements contained in this Annual Report on Form 10-K include "forward-looking statements." All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical fact, are forward-looking statements. Words such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," and similar expressions are intended to identify such forward-looking statements. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- the volatility of commodity prices for natural gas, natural gas liquids, or NGLs, and coal;
- our ability to access external sources of capital;
- any impairment writedowns of our assets;
- the relationship between natural gas, NGL and coal prices;
- the projected demand for and supply of natural gas, NGLs and coal;
- competition among producers in the coal industry generally and among natural gas midstream companies;
- the extent to which the amount and quality of actual production of our coal differs from estimated recoverable coal reserves;
- our ability to generate sufficient cash from our businesses to maintain and pay the quarterly distribution to our general partner and our unitholders;
- the experience and financial condition of our coal lessees and natural gas midstream customers, including our lessees' ability to satisfy their royalty, environmental, reclamation and other obligations to us and others;
- operating risks, including unanticipated geological problems, incidental to our coal and natural resource management or natural gas midstream business;
- our ability to acquire new coal reserves or natural gas midstream assets and new sources of natural gas supply and connections to third-party pipelines on satisfactory terms;
- our ability to retain existing or acquire new natural gas midstream customers and coal lessees;
- the ability of our lessees to produce sufficient quantities of coal on an economic basis from our reserves and obtain favorable contracts for such production;
- the occurrence of unusual weather or operating conditions including force majeure events;
- delays in anticipated start-up dates of our lessees' mining operations and related coal infrastructure projects and new processing plants in our natural gas midstream business;
- environmental risks affecting the mining of coal reserves or the production, gathering and processing of natural gas;
- the timing of receipt of necessary governmental permits by us or our lessees;
- hedging results;
- accidents;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators;
- uncertainties relating to the outcome of current and future litigation regarding mine permitting;
- risks and uncertainties relating to general domestic and international economic (including inflation, interest rates and financial and credit markets) and political conditions (including the impact of potential terrorist attacks);
- our ability to complete our previously announced merger; and
- other risks set forth in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2010.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission. 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.

Part I

Item 1 Business

General

Penn Virginia Resource Partners, L.P. (NYSE: PVR) is a publicly traded Delaware limited partnership 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: (i) coal and natural resource management and (ii) natural gas midstream.

Our operating income was $125.9 million in 2010, compared to $108.3 million in 2009 and $115.2 million in 2008. In 2010, our coal and natural resource management segment contributed $93.1 million, or 74%, to operating income, and our natural gas midstream segment contributed $32.8 million, or 26%, 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 to 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 properties and the subsequent collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage, fees.

As of December 31, 2010, we owned or controlled approximately 804 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. 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 2010, our lessees produced 34.5 million tons of coal from our properties and paid us coal royalties revenues of $130.3 million, for an average royalty per ton of $3.78. Approximately 80% of our coal royalties revenues in 2010 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.

In December, 2010, we announced a definitive agreement to purchase certain mineral rights and associated oil and gas royalty interests in Kentucky and Tennessee for approximately $97.3 million, subject to closing adjustments. The mineral rights include approximately 102.0 million tons of coal reserves and resources, and royalty interests from approximately 158 oil and gas wells. There are currently 14 active producing underground and surface mines on the approximately 126,000 acres of mineral estates being acquired, with 10 principal coal lessees operating the mines. The coal is primarily steam coal that is consumed by major electric utilities and other industrial customers in the southeastern United States. On January 25, 2011 we completed the purchase of these assets, which was funded by borrowings under our revolving credit facility ("Revolver").

Natural Gas Midstream Segment Overview

Our natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. As of December 31, 2010, we owned and operated natural gas midstream assets located in Oklahoma, Pennsylvania and Texas, including six natural gas processing facilities having 400 MMcfd of total capacity and approximately 4,263 miles of natural gas gathering pipelines. Our natural gas midstream business earns revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. In addition, we own member interests in joint ventures that gather and transport natural gas. We own a 25% member interest in Thunder Creek Gas Services, LLC, ("Thunder Creek"), a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. We own a 50% member interest in Crosspoint Pipeline, LLC ("Crosspoint"), a joint venture that gathers residue gas from our Crossroads Plant and transport it to market. 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.

In 2010, system throughput volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 129.7 Bcf, or approximately 355 MMcfd.

During 2010 we began construction of gathering systems in Wyoming and Lycoming Counties in Pennsylvania. We have completed construction of three miles of 12-inch gas gathering pipelines in Wyoming County and began gathering natural gas in June, 2010. Construction and development to provide gathering, compression and related services in Lycoming County continues and the first segment of the system began operations in February 2011. These gathering and transportation infrastructures will capture expected volumes in the Marcellus Shale area. This has been and will continue to be where a significant portion of our growth capital will be spent over the next year.

Changes in Our Management

In connection with Penn Virginia's (Penn Virginia Corporation NYSE: PVA) sale of its limited partner interest in Penn Virginia GP Holdings, L.P., or PVG, we implemented certain changes in management, as a result of which certain executive officers of Penn Virginia resigned as executive officers and directors of Penn Virginia Resource GP, LLC, or PVR GP, our general partner.

On March 8, 2010, A. James Dearlove resigned from his position as Chief Executive Officer of PVR GP, and on March 9, 2010, he resigned from his position as President and Chief Executive Officer of PVG GP, LLC, or PVG GP, the general partner of PVG. On March 8, 2010, the board of directors of PVR GP appointed William H. Shea, Jr. to the position of Chief Executive Officer of PVR GP, and on March 9, 2010 the board of directors of PVG GP appointed Mr. Shea to the positions of President and Chief Executive Officer of PVG GP.

On March 23, 2010, Frank A. Pici resigned from his position as Vice President and Chief Financial Officer of PVR GP, and his position as Vice President and Chief Financial Officer of PVG GP. On March 23, 2010, the board of directors of PVR GP appointed Robert B. Wallace to the position of Executive Vice President and Chief Financial Officer of PVR GP, and the board of directors of PVG GP appointed Mr. Wallace to the position of Executive Vice President and Chief Financial Officer of PVG GP.

On March 31, 2010, A. James Dearlove, Frank A. Pici and Nancy M. Snyder each resigned from their positions as directors on the board of directors of PVR GP. On March 31, 2010, Mr. Shea was appointed as a director on the board of directors of PVR GP and on the board of directors of PVG GP.

On June 7, 2010, Ms. Snyder resigned from her position as Vice President, Chief Administrative Officer, General Counsel and Assistant Secretary of PVR GP. On June 29, 2010 the board of directors of PVR GP appointed Bruce D. Davis, Jr. as Executive Vice President, General Counsel and Secretary of PVR GP.

Proposed Merger

On September 21, 2010, the Partnership announced that it had entered into an Agreement and Plan of Merger (the "Merger Agreement") by and among the Partnership, PVR GP, PVG, PVG GP, and PVR Radnor, LLC ("Merger Sub"), a wholly owned subsidiary of the Partnership, pursuant to which PVG and PVG GP will be merged into Merger Sub, with Merger Sub as the surviving entity (the "Merger"). Merger Sub will subsequently be merged into our general partner, PVR GP, with PVR GP being the surviving entity. In the transaction, PVG unitholders will receive consideration of 0.98 common units in the Partnership for each common unit in PVG representing aggregate consideration of approximately 38.3 million common units in the Partnership. Pursuant to the Merger Agreement and the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, the incentive distribution rights held by our general partner will be extinguished, the 2.0% general partner interest in the Partnership held by our general partner will be converted into a noneconomic interest and approximately 19.6 million common units in the Partnership owned by PVG will be cancelled.

The terms of the Merger Agreement were unanimously approved by our conflicts committee, comprised of independent directors, of the board of directors of our general partner, by the board of directors of our general partner, by the PVG conflicts committee, comprised of independent directors, of the board of directors of PVG's general partner, and by the board of directors of PVG's general partner (in each case with the chief executive officer of each general partner recusing himself from the board of directors approvals).

Pursuant to the Merger Agreement, PVG agreed to support the Merger by, among other things, voting its Partnership common units in favor of the Merger and against any transaction that, among other things, would materially delay or prevent the consummation of the Merger. The agreement to support automatically terminates if the conflicts committee of the board of directors or the board of directors of the general partner of PVG changes its recommendation to PVG's unitholders with respect to the Merger or the conflicts committee of the board of directors or the board of directors of our general partner changes its recommendation to the Partnership's unitholders with respect to the Merger.

After the Merger, the board of directors of our general partner, PVR GP, is expected to consist of nine members, six of whom are expected to be the existing members of the board and three of whom are expected to be the three existing members of the conflicts committee of the board of directors of PVG's general partner.

The Merger Agreement is subject to customary closing conditions including, among other things, (i) approval by the affirmative vote of the holders of a majority of our common units outstanding and entitled to vote at a meeting of the holders of our common units, (ii) approval by the affirmative vote of the holders of a majority of PVG's common units outstanding and entitled to vote at a meeting of the holders of PVG's common units, (iii) receipt of applicable regulatory approvals, (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance of our common units in connection with the Merger, (v) receipt of certain tax opinions, (vi) approval for listing our common units to be issued in connection with the Merger on the New York Stock Exchange and (vii) the execution of our Fourth Amended and Restated Agreement of Limited Partnership.

Current holders of our common units (the "Partnership unitholders") will continue to own their existing Partnership common units. Following the Merger, we will be owned approximately 46% by current Partnership unitholders and approximately 54% by former PVG unitholders. Our common units will continue to be traded on the New York Stock Exchange under the symbol "PVR" following the Merger.

PVG will be considered the surviving consolidated entity for accounting purposes, while we will be the surviving consolidated entity for legal and reporting purposes. The Merger will be accounted for as an equity transaction. Therefore, the changes in PVG's ownership interest as a result of the Merger will not result in gain or loss recognition.

On February 16, 2011, the Partnership held a special meeting to consider the vote upon the approval and adoption of the Merger and the other transactions contemplated by the Merger Agreement. At the special meeting, two matters were voted on and approved by a majority of the Partnership's unitholders. The first matter voted upon was the approval of the Merger Agreement and the transactions contemplated thereby. 67.52% or 35,308,687 of the Partnership's units outstanding and entitled to vote, voted in favor of this matter. The second matter voted upon was the approval of the Fourth Amended and Restated Partnership Agreement. 67.54% or 35,322,534 of the Partnership's units outstanding and entitled to vote, voted in favor of this matter.

On February 16, 2011, PVG announced that it had adjourned its special meeting of PVG unitholders originally scheduled for February 16, 2011 until March 9, 2011. Prior to the adjournment of the PVG special meeting, 20,688,419 units, or 52.94% of the PVG units outstanding and entitled to vote, voted in favor of the proposal to adjourn the special meeting to a later date to allow further time to solicit additional proxies from PVG unitholders. At the commencement of the PVG special meeting, the proxies received from unitholders totaled 25,353,727 million units, or 64.88% of all PVG units outstanding and entitled to vote. Of the total PVG units outstanding and entitled to vote, proxies representing 39.77% of the PVG units were in favor of the merger proposal. The approval of the Merger Agreement and related transactions requires the affirmative vote of holders of a majority of all units outstanding and entitled to vote. The reconvened PVG special meeting will be held at The Villanova University Conference Center, 601 County Line Road, Radnor, Pennsylvania 19087 on March 9, 2011 at 10:00 AM local time.

Business Strategy

Our primary business objective is to create sustainable, capital-efficient growth in cash available for distribution to our unitholders while maintaining a strong credit profile and financial flexibility. Our growth objective is largely dependent on the availability of open and reasonably priced capital markets. Subject to the availability of the capital markets, we are pursuing the following business strategies:

- *Continue to grow coal reserve holdings through acquisitions and investments in our existing market areas.* We continually seek new reserves of coal both to offset the depletion from production and to increase future production. We expect to continue to add to our coal reserve holdings in Central Appalachia and the Illinois Basin in the future, but may consider the acquisition of reserves outside of these basins if the market and quality of the reserves satisfy our criteria. We have historically operated in Central Appalachia, our largest area of coal reserves, but 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 the scrubbing of most coals, and not just the higher sulfur coal that is typically found in this basin. We will consider acquisitions of coal reserves that are long-lived and that are of sufficient size to yield significant production or serve as a platform for complementary acquisitions.
- *Expand in areas that complement our coal royalty business.* Timber and coal infrastructure projects typically involve long-lived assets that generally produce predictable cash flows. We own or control approximately 243,000 acres of forestlands in Appalachia, which primarily produce various hardwoods, and we own a number of coal infrastructure facilities. We also have an equity interest in a coal handling joint venture, which is expected to provide development opportunities for coal-related infrastructure projects.
- *Expand our natural gas midstream operations by adding new production to existing systems and acquiring or building new gathering and processing assets.* 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.
- *Mitigate commodity price exposure in our natural gas midstream segment.* Our natural gas midstream operations consist of a mix of fee-based and margin-based services that, together with our hedging activities, are expected to generate relatively stable cash flows. During the quarter ended December 31, 2010, approximately 22% of the system throughput volumes in our natural gas midstream segment were gathered or processed under fee-based contracts. Under fee-based contracts, we are not exposed directly to commodity price risk. The remainder of our system throughput volumes were gathered or processed under gas purchase/keep-whole arrangements and percentage-of-proceeds arrangements that are subject to commodity price risk. However, we expect to manage our exposure to commodity price risk by entering into hedging transactions. Based upon current volumes, we have entered into hedging agreements covering approximately 55% and 32% of our commodity-sensitive volumes in 2011 and 2012. Historically, we have generally targeted hedging 50% to 60% of our commodity-sensitive volumes covering a two-year period.

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 is earned under long-term leases that require the lessees to make royalty payments to us based on fixed royalty rates that 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, 2010, 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) gas purchase/keep-whole and (ii) percentage-of-proceeds. For the fourth quarter of 2010, approximately 16% of our system throughput volumes were gathered or processed under gas purchase/keep-whole contracts, 62% were gathered or processed under percentage-of-proceeds contracts and 22% were gathered or 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.

In 2010, 17%, 14%, 11% and 10% of our natural gas midstream segment revenues and 14%, 11%, 9% and 8% of our total consolidated revenues resulted from four of our natural gas midstream customers, Conoco Phillips Company, Tenaska Marketing Ventures, Targa Liquids Marketing and Trade and Williams NGL Marketing, LLC.

Gas Purchase/Keep-Whole Arrangements 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 business, results of operations or financial condition.

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.

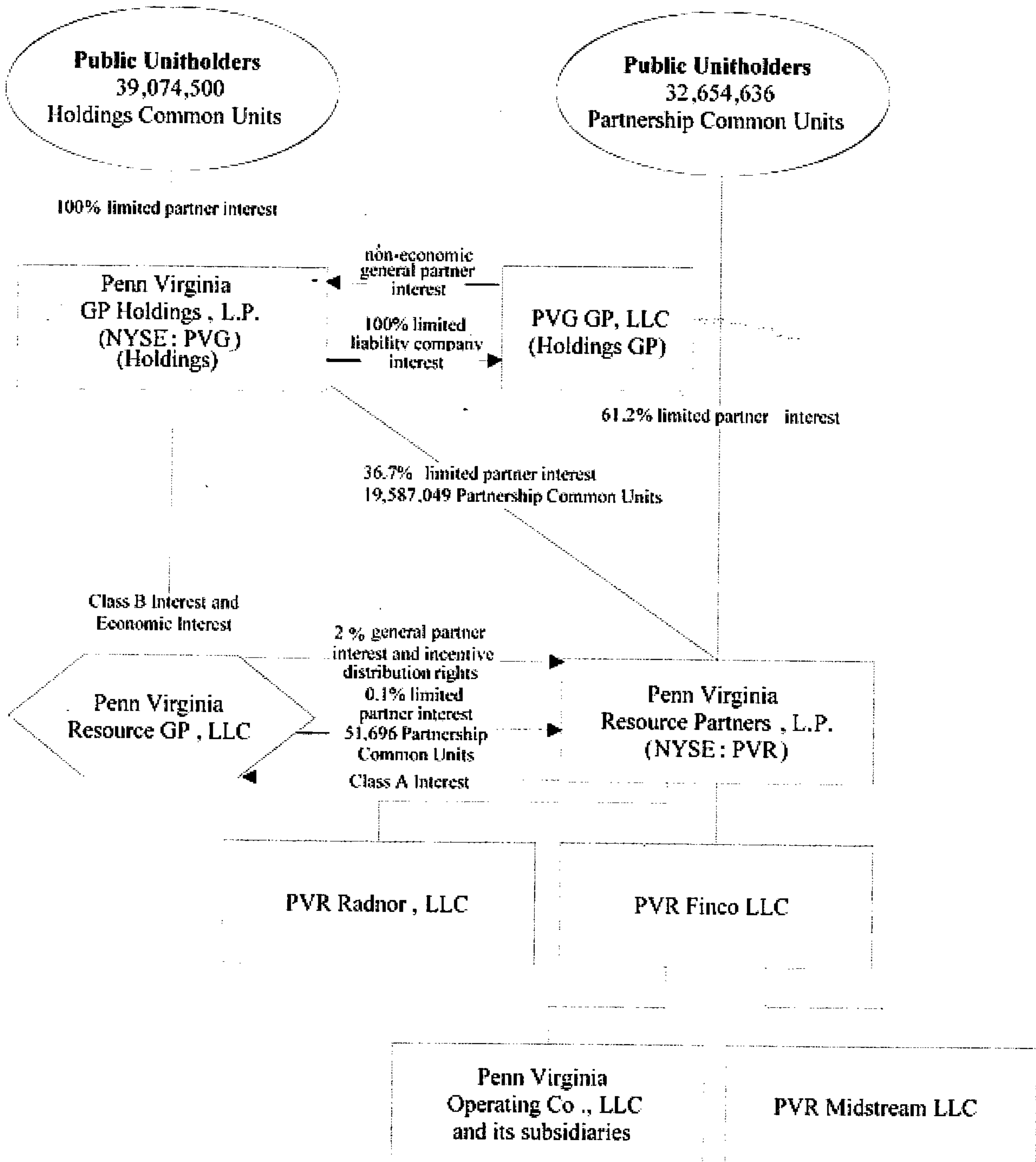
Natural Gas Marketing Contracts We are also engaged in natural gas marketing by aggregating third-party volumes and selling those volumes into interstate and intrastate pipeline systems such as Enogex and Panhandle Eastern Pipeline and at market hubs accessed by various interstate pipelines. Revenues 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 three years ended December 31, 2010, natural gas marketing activities generated $2.8 million, $1.8 million and $5.8 million in net revenues for 2010, 2009 and 2008.

Commodity Derivative Contracts We utilize 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 NGLs that we sell after processing. We hedge against the variability in our frac spread by entering into costless collar and swap derivative contracts to sell NGLs forward at a predetermined commodity 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, such use may also limit future revenues or cost savings from favorable price movements.

See Note 6 to the Consolidated Financial Statements for a further description of our derivatives program.

Partnership Structure

We completed our initial public offering in October 2001. Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through a wholly owned subsidiary, PVR Finco LLC, which is the sole member of the operating company for the coal and natural resource management segment, Penn Virginia Operating Co., LLC, or PVR Coal, and the operating company for the natural gas midstream segment, PVR Midstream LLC, or PVR Midstream. The following diagram depicts our and our affiliates' simplified organizational and ownership structure as of December 31, 2010:



Relationship with PVG

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. In addition, under a non-compete agreement between us, our general partner, and PVG and its general partner, PVG and its affiliates must offer us the right of first refusal on any potential acquisition of assets relating to any coal or natural gas businesses. PVG and its affiliates are not otherwise prohibited from engaging in activities that directly compete with us, even if we would have a conflict of interest with PVG with respect to such business opportunity.

Partnership Distributions

Cash Distributions

We paid cash distributions of $1.88 per common unit during the year ended December 31, 2010. In the first quarter of 2011, we paid a cash distribution of $0.47 ($1.88 on an annualized basis) per common unit with respect to the fourth quarter of 2010. This distribution was unchanged from the previous distribution paid on November 12, 2010.

The following table reflects the allocation of total cash distributions paid by us during the years ended December 31, 2010, 2009 and 2008 (in thousands, except per unit information):

	Year Ended December 31, 2010	2009	2008
Limited partner units	$ 97,889	$ 97,382	$ 89,207
General partner interest (2%)	1,999	1,988	1,820
Incentive distribution rights	24,267	24,140	20,049
Phantom units	440	499	-
Total cash distributions paid	$ 124,595	$ 124,009	$ 111,076
Total cash distributions paid per limited partner unit	$ 1.88	$ 1.88	$ 1.82

Incentive Distribution Rights

In accordance with our partnership agreement, incentive distribution rights, or IDRs, 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 ($1.00 on an annualized basis) per unit. Our general partner currently holds 100% of the IDRs, 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 the IDRs will require the affirmative vote of holders of a majority of the outstanding common units. On or after September 30, 2011, the IDRs will be freely transferable. The IDRs 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.

Since 2001, we have increased our quarterly cash distribution from $0.25 ($1.00 on an annualized basis) per unit to $0.47 ($1.88 on an annualized basis) per unit, which is our most recently declared distribution. These increased cash distributions have placed our general partner at the maximum target cash distribution level as described above and, as a consequence, since reaching such level, our general partner has received 50% of available cash in excess of $0.375 per unit.

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 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 equal to the greater of (i) 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 (ii) 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 of this right of our general partner, 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 22, 2010, PVG and its affiliates owned 19,638,745 common units, representing approximately 37% 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 affiliate, PVG, on the one hand, and us and our unitholders, on the other hand. Our general partner is controlled by PVG. Accordingly, PVG has the ability to elect, remove and replace the non-independent directors and all of the 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. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders.

All of our general partner's executive officers are also officers of PVG's general partner and one of our general partner's directors is also a director of PVG's general partner, and each has a fiduciary duty to manage the business of PVG in a manner beneficial to PVG and its unitholders. Consequently, this director and all of the officers may encounter situations in which their fiduciary obligations to 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 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.

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.

We are required by our partnership agreement 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, or CAA, requirements.

Natural Gas Midstream Segment

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 we do.

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.

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, or new interpretations of existing laws 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 federal Clean Air Act ("CAA") and corresponding state and local laws and regulations affect all aspects of coal mining operations, 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 Environmental Protection Agency, or 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 ("SIPs"), 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. 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 would have permanently capped nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. In 2008, the D.C. Circuit Court of Appeals after initially vacating CAIR, issued an opinion to remand without vacating CAIR. Therefore, CAIR has remained in effect while the EPA conducts rulemaking to modify CAIR to comply with the Court's July 2008 opinion. In lieu of CAIR, in July 2010, the EPA proposed the Transport Rule which sets a pollution limit on nitrogen oxide and sulfur dioxide emissions in 31 states and the District of Columbia. The public comment period has ended and the EPA expects to issue a final rule in Spring 2011. Under the Transport Rule, some coal-fired power plants might be required to install additional pollution control equipment which could lead to decreased demand for low-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. The EPA appealed the decision to the U.S. Supreme Court in October 2008, but withdrew its petition for certiorari on February 6, 2009. However, a utility group continues to seek certiorari, challenging the court of appeals decision to overturn CAMR. In the meantime, the EPA plans to develop standards consistent with the court of appeal's ruling, intending to propose air toxics standards for coal- and oil-fired electric generating units by March 10, 2011, and finalize a rule by November 16, 2011. In conjunction with these efforts, on December 24, 2009, the EPA approved an Information Collection Request (ICR) requiring all U.S. power plants with coal or oil-fired electric generating units to submit emissions information for use in developing air toxics emissions standards. Moreover, on April 29, 2010, EPA proposed new Maximum Achievable Control Technology for several classes of boilers and process heaters, including large coal-fired boilers and process heaters, which would require significant reductions in the emission of particulate matter, carbon monoxide, hydrogen chloride, dioxins and mercury. In addition, various states have promulgated or proposed 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 SIPs 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 revised ozone National Ambient Air Quality Standards ("NAAQS"), significant additional emissions control expenditures may be required at coal-fired power plants. Attainment dates for the new standards range between 2013 and 2030, depending on the severity of the non-attainment. In July 2009, the U.S. Court of Appeals for the District of Columbia vacated part of a rule implementing the ozone NAAQs and remanded certain other aspects of the rule to the EPA for further consideration. Notwithstanding the decision, we expect that additional emissions control requirements may be imposed on new and expanded coal-fired power plants and industrial boilers in the years ahead. 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 SIPs 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. Demand for our steam coal could be affected when these standards are implemented by the applicable states.

On June 3, 2010, EPA issued a final rule setting forth a more stringent primary NAAQS applicable to sulfur dioxide. The rule also modifies the monitoring increment for the sulfur dioxide standard, establishing a 1-hour standard, and expands the sulfur dioxide monitoring network. Attainment designations will be made pursuant to the modified standards by June 2012. States with non-attainment areas will have until 2014 to submit SIP revisions which must meet the modified standard by August 1, 2017; for all other areas, states will be required to submit "maintenance" SIPs by 2013. EPA also plans to address the secondary sulfur dioxide standard, which is currently under review. As a result, coal-fired power plants, which are the largest end users of our coal, may be required to install additional emissions control equipment or take other steps to lower sulfur emissions.

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. 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.

Climate Change

In 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for greenhouse gases, went into effect for those nations that ratified it. The United States is not participating in this treaty. However, the United States is actively participating in international discussions that are currently underway to develop a treaty to replace the Kyoto Protocol after its expiration, with a goal of reaching a consensus on a replacement treaty. Any replacement treaty or other international arrangement requiring additional reductions in greenhouse gas emissions could have a global impact on the demand for coal.

Future regulation of greenhouse gases in the United States could occur pursuant to future U.S. treaty commitments, new domestic legislation that may impose a carbon emissions tax or establish a cap-and-trade program or regulation by the EPA. The Obama Administration has indicated its support for a mandatory cap and trade program to reduce greenhouse gas emissions and the U.S. Congress is considering various proposals to reduce greenhouse gas emissions, mandate electricity suppliers to use renewable energy sources to generate a certain percentage of power, and require energy efficiency measures. Passage of such comprehensive climate change and energy legislation could impact the demand for coal. Any reduction in the amount of coal consumed by North American electric power generators could reduce the price of coal that our lessees mine and sell, thereby reducing our royalties revenues.

Even in the absence of new federal legislation, greenhouse gas emissions have begun to be regulated by the EPA pursuant to the CAA. In response to the April 2, 2007 U.S. Supreme Court ruling in *Massachusetts, et al. v. EPA* that the EPA has authority to regulate greenhouse gas emissions under the CAA the EPA has taken several steps towards implementing regulations regarding the emission of greenhouse gases. In 2009, EPA issued a final rule declaring that six greenhouse gases, including carbon dioxide and methane, "endanger both the public health and the public welfare of current and future generations" , allowing the EPA to begin regulating greenhouse gas emissions under existing provisions of CAA. In May 2010, the EPA issued a final "tailoring rule" that phases in various greenhouse-gas-related permitting requirements beginning in January 2011. Until June 30, 2011, only sources currently subject to CAA prevention of significant deterioration or operating permit programs will be subject to greenhouse gas permitting requirements. Beginning July 1, 2011, these permitting programs will extend to newly built sources emitting more than 100,000 tons of greenhouse gases per year and modified facilities increasing their emissions by at least 75,000 tons of greenhouse gases per year. EPA's rule clarifies that "smaller sources," those with emissions of less than 50,000 tons of greenhouse gases per year, will not be regulated until at least April 30, 2016, and may in fact be permanently excluded from the permitting requirements. In December 2010, the EPA issued its plan to update pollution standards for fossil fuel power plants and petroleum refineries. Under that agreement, EPA intends to propose standards for power plants in July 2011 and for refineries in December 2011 and will issue final standards in May 2012 and November 2012, respectively.

The permitting of a number of proposed new coal-fired power plants has also been contested by environmental organizations for concerns related to greenhouse gas emissions from new plants. For instance, 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. Other state regulatory authorities 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 EPA's Environmental Appeals Board, or EAB, and other judicial forums under the CAA. For example, in June 2008, a Georgia court voided a CAA permit and halted the construction of a coal-fired power plant for failure to address carbon dioxide emissions. Also, a federal appeals court has allowed a lawsuit pursuing federal common law claims to proceed against certain utilities on the basis that they may have created a public nuisance due to their emissions of carbon dioxide, while a second federal appeals court dismissed a similar case on procedural grounds. The U.S. Supreme Court has agreed to hear the appeal of the lower court's decision.

A number of 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, ten northeastern and mid-Atlantic states have agreed to implement a regional cap-and-trade program, referred to as the Regional Greenhouse Gas Initiative, or RGGI, to stabilize carbon dioxide emissions from regional power plants beginning in 2009. The members of RGGI have established in statute and/or regulation a carbon dioxide trading program. Auctions for carbon dioxide allowances under the program began in September 2008. Following the RGGI model, seven Western states and four Canadian provinces 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, including fossil-fuel fired power plants, in participating states through trading of emissions credits beginning in 2012. Similarly, in 2007, six Midwestern states and one Canadian province signed the Midwestern Greenhouse Gas Reduction Accord to develop and implement steps to reduce greenhouse gas emissions, including developing a market-based, multi-sector cap. Some states have passed laws individually. For example, 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. In 2007, New Jersey passed a greenhouse gas reduction that would be economy wide, requiring emissions to drop to 1990 levels by 2020 and that emissions be capped at 80% of 2006 levels by 2050.

It is possible that future international, federal and state initiatives to control 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 of our lessees' customers switching to alternative sources of fuel, or otherwise adversely affect our lessee's operations and demand for our coal, which could have a material adverse effect on our royalties revenues.

Surface Mining Control and Reclamation Act

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 requires mine operators to post performance bonds to ensure compliance with any reclamation obligations. Moreover, 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 on the theory that we "owned" or "controlled" the mine operator in such a way for liability to attach. 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. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation of orphaned mine sites and abandoned mine drainage control on a statewide basis.

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 and also require dredge and fill permits under Section 404 for the construction of slurry ponds, stream impoundments, sediment control ponds and valley fills. The EPA issues permits for the discharge of pollutants into navigable waters while the Army Corps of Engineers, or Army Corps, issues dredge and fill permits under Section 404 of the CWA. Although the CWA has long authorized EPA to review 404 permits issued by the Army Corps, EPA has only recently begun reviewing 404 permits issued by the Army Corps for coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by EPA regarding these permits.

For instance, even though the State of West Virginia has been delegated the authority to issue permits for coal mines in that state, the EPA is taking a more active role in its review of NPDES permit applications for coal mining operations in Appalachia. EPA has stated that it plans to review all applications for NPDES permits. Indeed, interim final guidance issued by the EPA on April 1, 2010, encourages EPA Regions 3, 4 and 5 to (1) object to the issuance of state program NPDES permits where the Region does not believe that the proposed permit satisfies the requirements of the CWA, and (2) exercise a greater degree of oversight with regard to state issued general Section 404 permits.

In addition, the April 1, 2010, interim final guidance also addresses the Regions' involvement in Section 404 permitting decisions. This guidance follows up on the June 11, 2009 Enhanced Coordination Process Memoranda for the issuance of 404 permits whereby EPA undertook a new level of review of 404 permits than it had previously undertaken. Ultimately, EPA identified 79 coal-related applications for 404 permits that would need to go through that process. EPA's actions in issuing the Enhanced Coordination Process Memoranda and the guidance are being challenged in a lawsuit pending before the United States District Court for the District of Columbia in a case captioned *National Mining Assoc. v. U.S. Environmental Protection Agency.* In a ruling issued on January 18, 2011, the District Court held that these measures "are legislative rules that were adopted in violation of the APA's notice and comment requirements." The court would not grant the motion for a preliminary injunction to enjoin further use of these measures but also refused to dismiss the Complaint as the EPA had sought.

Not only is EPA reviewing new permits before they are issued, EPA has recently exercised its "veto" power on January 14, 2011 to withdraw or restrict the use of previously issued permits in connection with the Spruce No. 1 Surface Mine in West Virginia, which is one of the largest surface mining operations ever authorized in Appalachia. This action is the first time that such power was exercised with regard to a previously permitted coal mining project. More frequent use of the EPA's Section 404 "veto" power as well as the increased risk of application of this power to previously permitted projects could create uncertainly with regard to our lessees' continued use of their current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting our coal royalties revenues.

These initiatives have extended the time required to obtain permits for coal mining and we anticipate further delays in obtaining permits and that the costs associated with obtaining and complying with those permits will increase substantially. In addition, 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. It is possible that some of our lessees' projects may not be able to obtain these permits because of the manner in which these rules are being interpreted and applied. It is also possible that our lessees may be unable to obtain or may experience delays in securing, utilizing or renewing additional Section 404 individual permits for surface mining operations due to agency or court decisions stemming from the above developments.

Our lessess may no longer seek general permits under Nationwide Permit 21 ("NWP 21") adopted by the Army Corps under its authority in Section 404 of the CWA because on June 17, 2010, the Army Corps suspended the use of NWP 21 in the Appalachian states where our lessees operate, but NWP 21 authorizations already granted remain in effect. While the suspension is in effect, our lessees must seek 404 permits on an individual basis subject to the EPA measures discussed above with the uncertainties and delays attendant to that process for now.

In December 2008, the Department of Interior published the Excess Spoil, Coal Mine Waste and Buffers for Perennial and Intermittent Streams rule under SMCRA in part to clarify when valley fills are permitted. The rule would require a 100-foot buffer around all waters, including streams, lakes, ponds and wetlands. However, the rule would exempt certain activities, such as permanent spoil fills and coal waste disposal facilities, and allow mining that changes a waterway's flow, providing the mining company repairs damage later. Companies could also receive a permit to dispose of waste within the buffer zone if they explain why an alternative is not reasonably possible or is not necessary to meet environmental requirements. Environmental groups brought lawsuits challenging the rule and in a March 2010 settlement with litigation parties, the OSM agreed to use best efforts to sign a proposed rule by February 28, 2011 and a final rule by June 29, 2012. In addition, Congress has proposed, and may in the future propose, legislation to restrict the placement of mining material in streams.

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 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. 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.

Mining accidents in the last several years in West Virginia, Utah, 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. More stringent mine safety laws and regulations promulgated by these states and the federal government have included increased sanctions for non-compliance. Other states have proposed or passed similar bills, resolutions or regulations addressing mine safety practices. Moreover, workplace accidents, such as the April 5, 2010, Upper Big Branch Mine incident, are likely to result in more stringent enforcement and possibly the passage of new laws and regulations.

In 2006, the Mine Improvement and New Emergency Response Act ("Miner Act") was enacted 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. Since passage of the Miner Act, enforcement scrutiny has also increased, including more inspection hours at mine sites, increased numbers of inspections and increased issuance of the number and the severity of enforcement actions and related penalties. Various states also have enacted their own new laws and regulations addressing many of these same subjects. The Dodd Frank Bill that was enacted by Congress in 2010 now requires mining companies including coal companies to include various safety statistics regarding citations, penalties, notices of violation and pending legal actions in periodic reports that are required by the securities laws. These disclosures may lead to the enactment of yet further legislation regarding mine safety.

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.

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 natural gas pipelines to comply with safety standards in constructing and operating the pipelines, and subjects pipelines to regular inspections. We also operate a NGL pipeline that is subject to regulation by the U.S. Department of Transportation under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. 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 Wastes." 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 CERCLA "hazardous substance," or be subject to regulation under state laws.

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 210 employees who directly supported our operations at December 31, 2010. 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 website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Compensation and Benefits Committee Charter 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 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 references to the "SEC" refer to the Securities and Exchange Commission. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with, or furnish to, the SEC.

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

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, results of operations, as well as any related benefits of owning our securities could be materially and adversely affected.

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;
- our timely receipt of payments from our lessees;
- the amount of natural gas transported in our gathering systems;
- the amount of throughput in our processing plants;
- the price of and demand for natural gas;
- the price of and demand for NGLs;
- our timely receipt of payments from our natural gas and NGL customers;
- the relationship between natural gas and NGL prices, which impact the effectiveness of our hedging program; and
- the fees we charge and the margins we realize for our natural gas midstream services.

In addition, the actual amount of cash that we will have available for distribution will depend on other factors 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.

Our indebtedness may limit our ability to borrow additional funds, make distributions to our unitholders, or capitalize on acquisition or other business opportunities, in addition to impairing our ability to fulfill our debt obligations.

As of December 31, 2010, our total outstanding long-term indebtedness was approximately $708.0 million. While we are permitted by our partnership agreement 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 to our unitholders. Furthermore, our leverage, various limitations in the agreements governing our revolving credit facility ("Revolver"), other restrictions governing our indebtedness and the indenture governing our senior notes ("Senior Notes") may reduce our ability to incur additional indebtedness, to engage in some transactions and to capitalize on acquisition or other business opportunities.

Our indebtedness and other financial obligations could have important consequences. For example, they could:

- make it more difficult for us to make distributions to our unitholders;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general partnership purposes or other purposes;
- result in higher interest expense in the event of increases in interest rates since some of our debt is, and will continue to be, at variable rates of interest;
- have a material adverse effect on us if we fail to comply with financial and restrictive covenants in our debt agreements and an event of default occurs as a result of that failure that is not cured or waived;

- require us to dedicate a substantial portion of our cash flow to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general partnership requirements;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared to our competitors that have proportionately less debt.

If we are unable to meet our debt service obligations and other financial obligations, we could be forced to restructure or refinance our indebtedness and other financial transactions, seek additional equity capital or sell our assets. We may then be unable to obtain such financing or capital or sell our assets on satisfactory terms, if at all.

Restrictive covenants in the agreements governing our indebtedness may reduce our operating flexibility.

The indenture governing our outstanding Senior Notes and credit agreement governing our Revolver and any agreements governing our other future indebtedness contain or may contain various covenants limiting our ability and the ability of our specified subsidiaries to, among other things:

- pay distributions on, redeem or repurchase our equity interests or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred securities;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- create non-guarantor subsidiaries.

These restrictions could limit our ability and the ability of our subsidiaries to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general, conduct operations, or otherwise take advantage of business opportunities that may arise. Our Revolver contains covenants requiring us to maintain specified financial ratios and satisfy other financial conditions. We may be unable to meet those ratios and conditions. Any future breach of these covenants and our failure to meet any of those ratios and conditions could result in a default under the terms of our Revolver, which could result in the acceleration of our debt and other financial obligations. Additionally, our Revolver is secured by substantially all of our assets, and if we are unable to satisfy our obligations thereunder, the lenders could seek to foreclose on our assets. The lenders may also sell 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. 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 the Revolver.

Our unitholders do not elect our general partner and only elect a limited number of the 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 and will have no right to elect our general partner on an annual or other continuing basis in the future. Our unitholders have the ability to elect the independent directors of the board of directors of our general partner. The remaining directors of our general partner are 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 the approval of our unitholders, which would dilute their ownership interests and may increase the risk that we will not have sufficient available cash to maintain or increase our cash distributions.

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 our 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 independent members of the board of directors and all of the officers of our general partner with individuals it chooses.

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

Under Delaware law, our unitholders 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 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.

Risks Related to Conflicts of Interest

Potential conflicts of interest may arise among our general partner, its affiliates, including PVG, 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.

PVG owns an approximately 37% limited partner interest in us and owns and controls our general partner. Conflicts of interest may arise between our general partner and its affiliates, including 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 PVG, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.
- 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 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, all of our general partner's executive officers are also officers of PVG's general partner and one of our general partner's directors is also a director of PVG's general partner, and each has fiduciary duties to manage the business of PVG in a manner beneficial to PVG and its unitholders. Consequently, this director and all of the 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, our unitholders 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.

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

If at any time more than 80% of our outstanding common units are owned by our general partner and its affiliates, our general partner will have 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 units held by unaffiliated persons at a price equal to the greater of (i) 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 (ii) 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, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. 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. An affiliate of our general partner, PVG, currently owns approximately 37% of our outstanding common units.

Risks Related to Our Coal and Natural Resource Management Business

If our lessees do not manage their operations well or experience financial difficulties, 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, or if they experience financial difficulties, their production could be reduced, which would result in lower coal royalties revenues to us and could have a material adverse effect on our business, results of operations or financial condition.

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 could have a material adverse effect on our business, results of operations or financial condition. 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 have a material adverse effect on our business, results of operations or financial condition.

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. In addition, because a majority of our coal royalties are 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, our coal royalties revenues could be reduced by such a decline. Such a decline could also reduce 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. The future state of the global economy, including financial and credit markets on coal production levels and prices is uncertain. Depending on the longevity and ultimate severity of this downturn, demand for coal may decline, which could adversely effect production and pricing for coal mined by our lessees, and, consequently, adversely effect the royalty income received by us.

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 the year ended December 31, 2010, five primary operators, each with multiple leases, accounted for 73% 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.

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 and we could, therefore, experience a material adverse effect on our business, results of operations or financial condition. If we are able to 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, lack of credit availability, 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' workforces could become increasingly unionized in the future, which could adversely affect their productivity and thereby reduce our coal royalties revenues.

One of our lessees has one mine operated by unionized employees. This mine was our second largest mine on the basis of coal production for the year ended December 31, 2010. 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.

We could be negatively impacted by any decline in the market demand for coal.

The domestic demand for, and price of our coal primarily depend on coal consumption patterns of the domestic electric utility industry. Consumption by the domestic electric utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel sources, such as natural gas, nuclear, hydroelectric power and other renewable energy sources. During the last several years, the U.S. coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. Increased competition by coal producers or producers of alternate fuels could decrease the demand for, or pricing of, or both, for our coal, adversely impacting demand for the coal that our lessees produce and thereby reducing our coal royalties revenues.

In addition, 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. 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."

Federal and state laws restricting the emissions of greenhouse gases in many jurisdictions could adversely affect our coal royalties revenues.

Global climate change continues to attract considerable public and scientific attention. Several scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases", or GHG's, including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. Legislative attention in the United States is being paid to reducing GHG emissions. Many states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the development of regional greenhouse gas cap-and-trade programs.

There are many regulatory approaches currently in effect or being considered to address greenhouse gases, including possible future U.S. treaty commitments, new federal or state legislation that may impose a carbon emissions tax or establish a cap-and-trade program and regulation by the EPA. EPA rules require extensive regulation of GHG emissions from mobile sources and stationary sources, including imposing permitting requirements and obligations to use best available control technology for the reduction of GHG emissions whenever certain stationary sources, such as power plants, are built or significantly modified. Moreover, the EPA plans to update pollution standards for fossil fuel power plants and petroleum refineries.

The permitting of new coal-fired power plants has also been contested by state regulators and environmental organizations for concerns related to greenhouse gas emissions from the new plants. Other state regulatory authorities 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 emissions of carbon dioxide. In addition, several permits issued to new coal-fired power plants without limits on greenhouse gas emissions have been appealed to EPA's Environmental Appeals Board. The regulation of emissions of GHGs associated with the use of coal may lead our lessees' customers to curtail their operations, switch to other fuels or other alternatives which may, individually and collectively, reduce demand for our lessees' coal and thereby decrease revenues. See Item 1, "Business — Governmental Regulation and Environmental Matters — Coal and Natural Resource Management Segment — Air Emissions." As a result of current laws and proposed laws, regulations and trends, electric generators may switch from coal to other fuels that generate less greenhouse gas emissions, possibly reducing demand for coal.

Delays in obtaining, inability to obtain, or revocation of our lessees' mining 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, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by regulators, all of which may make compliance more difficult, and may possibly preclude the continuance of ongoing mining operations or the development of future mining operations.

To dispose of mining overburden generated from surface mining activities, our lessees often need to obtain government approvals, including CWA Section 404 permits to construct valley fills, stream impoundments, and sediment control ponds. Recently, these Section 404 permits and the Section 404 permitting standard have been the target of increased scrutiny by environmental groups, legislators, the White House, and the EPA which has made it more difficult for miners to obtain, and in some cases maintain, Section 404 permits. In some cases, the EPA is retroactively rescinding permits that have been issued. Please see Item 1, "Business — Government Regulation and Environmental Matters — Coal and Natural Resource Management Segment — Clean Water Act," for a discussion of recent litigation and regulatory developments related to the CWA. An inability by our lessees to obtain these key permits will prevent them from conducting their mining operations pursuant to applicable laws and would reduce coal production and cash flows, which could ultimately have an adverse effect on our royalties revenues.

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 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. 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.

Our lessees operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us.

Our lessees operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own as well as at sites that we previously owned, or may acquire. We may be held responsible for more than our share of the contamination or other damages, or even for the entire share.

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.

We typically do not obtain independent evaluations of natural gas reserves dedicated to our gathering systems; therefore, volumes of natural gas on our systems in the future could be less than we anticipate.

We typically do not obtain independent evaluations of natural gas reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information, as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves dedicated to our gathering systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems is less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas gathered on our gathering systems in the future could be less than we anticipate. A decline in the volumes of natural gas on our systems could have a material adverse effect on our business, results of operations or financial condition.

A reduction in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect our business, results of operations and financial condition.

The NGL products we produce, including ethane, propane, normal butane, isobutane and natural gasoline, have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general economic conditions, new government regulations, reduced demand by consumers for products made with NGL products, increased competition from petroleum-based products due to pricing differences, mild winter weather or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services. Any reduced demand for our NGL products could adversely affect demand for the services we provide as well as NGL prices, which would negatively impact our results of operations and financial condition.

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 2010, we generated a majority of our gross 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 — gas purchase/keep-whole and percentage-of-proceeds arrangements. See Item 1, "Business — Contracts — Natural Gas Midstream Segment."

Virtually all of the system throughput volumes in our Crescent System and Hamlin System are processed under percentage-of-proceeds arrangements. The system throughput volumes in our Panhandle System are processed 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 on either an index price or the price actually received for the gas and 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 business, results of operations or financial condition. 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 business, results of operations or financial condition.

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 state of the global economy, including financial and credit markets on worldwide demand for oil and domestic demand for natural gas and NGLs;
- 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. Readily available access to debt and equity capital and credit availability have been and continue to be critical factors in our ability to grow. While global financial markets and economic conditions have been disrupted in the past, these conditions have improved more recently. The cost of raising money in the debt and equity capital markets has increased while the availability of funds from these markets generally has diminished. Depending on the longevity and ultimate severity of a downturn, our ability to make acquisitions may be significantly adversely affected. In the event we complete acquisitions, 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 might not generate increases in our cash distributions to our unitholders, and because of the capital used to complete such acquisitions, or the debt incurred, our results of operations may change significantly.

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. . While global financial markets and economic conditions have been disrupted in the past, these conditions have improved more recently. Depending on the longevity and ultimate severity of this downturn, our ability to access new capital to fund new projects in a cost-effective manner may be significantly adversely impacted. If we do undertake these projects, they may not be completed on schedule, or at all, or at the anticipated 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 have a material adverse effect on our business, results of operations or financial condition.

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 2010, 17%, 14%, 11% and 10% of our natural gas midstream segment revenues and 14%, 11%, 9% and 8% of our total consolidated revenues resulted from four of our natural gas midstream customers, Conoco Phillips Company, Tenaska Marketing Ventures, Targa Liquids Marketing and Trade and Williams NGL Marketing, LLC. Any nonpayment or nonperformance by our natural gas midstream segment 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 condensate, 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 NGL prices were to rise (or prices decline with respect to natural gas hedges entered into to lock the frac spread) over the price established by the hedging arrangements. Moreover, we have entered into derivative transactions related to only a portion of our condensate, natural gas and NGL volumes. As a result, we will continue to have direct commodity price risk with respect to the unhedged portion of these volumes. 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.

The accounting standards regarding hedge accounting are complex, and even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our Consolidated Financial Statements may reflect volatility due to these derivatives, even when there is no underlying economic impact at that point. In addition, it is not always possible for us to engage in a derivative transaction that completely mitigates our exposure to commodity prices. Our Consolidated Financial Statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge transaction.

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 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 business, results of operations or financial condition. 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 business, results of operations or 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 our natural gas midstream segment 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 business, 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."

The natural gas midstream segment may record impairment losses on its long-lived assets.

The natural gas midstream segment has completed a number of acquisitions in recent years, including the North Texas System (Lone Star Gathering, L.P., or Lone Star). See Note 3 to the Consolidated Financial Statements for a description of our natural gas midstream segment's material acquisitions. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, and the resulting amount of goodwill, if any. Unforeseen changes in operations, the business environment or market conditions could substantially alter management's assumptions and could result in lower estimates of values of acquired assets or of future cash flows. This could result in impairment charges being recorded in our Consolidated Statements of Income.

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 Internal Revenue Service, or 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 our unitholders 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. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause us to be treated as a corporation for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes for any taxable year we would pay federal income tax on our taxable income for such years at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again in the same manner as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders 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 could materially and adversely affect our ability to make payments on our debt.

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.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. Specifically, 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, at the federal level, legislation has recently been considered that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have appeared to apply to us as considered, it could be reintroduced and amended prior to enactment in a manner that does apply to us. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any similar changes will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

At the state level, 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 an 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 gross income apportioned to Texas in the prior year. Imposition of such a tax on us by Texas and other states 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.

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.

Our unitholders may be required to pay taxes on their share of our income even if they 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, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from the taxation of their share of our taxable income.

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

If a unitholder sells his or her common units, he or she 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 such unitholder in excess of the total net taxable income allocated to him or her, which decreased his or her tax basis in his or her common units, will, in effect, become taxable income to such unitholder if the common units are sold at a price greater than such unitholder's tax basis in those common units, even if the price he or she receives is less than that unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income to the unitholder due to recapture items, including depreciation recapture. In addition, if a unitholder sells his or her common units, he or she may incur a tax liability in excess of the amount of cash such unitholder received from the sale because the amount realized from the sale includes a unitholder's share of our nonrecourse liabilities.

Tax-exempt entities and non-U.S. 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 U.S. federal income tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their 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. A unitholder will bear the cost of any expense incurred in connection with an examination of his or her 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.

To maintain the uniformity of the economic and tax characteristics of our common units, we have adopted 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 a unitholder's 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, and if the IRS were to challenge this method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the protection method we have adopted. If the IRS were to challenge our proration 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 should 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 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. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests publicly traded partnership technical termination relief and the IRS grants such relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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

In addition to federal income taxes, our unitholders 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 conduct business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders 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, our unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of our unitholders to file all U.S. federal, state and local tax returns that may be required of each of them.

Risks Related to the Potential Merger

While the Merger Agreement is in effect, we may be limited in our ability to pursue other attractive business opportunities.

While the Merger Agreement is in effect, we have agreed to refrain from taking certain actions with respect to our businesses and financial affairs pending the consummation of the Merger or termination of the Merger Agreement. These restrictions could be in effect for an extended period of time if the consummation of the Merger is delayed. These limitations do not preclude us from conducting our business in the ordinary or usual course or from acquiring assets or businesses so long as such activity does not have a "material adverse effect" as such term is defined in the Merger Agreement or materially affect our ability to complete the transactions contemplated by the Merger Agreement.

In addition to the economic costs associated with pursuing the Merger, the management of our general partner will continue to devote substantial time and other human resources to the proposed Merger which could limit our ability to pursue other attractive business opportunities, including potential joint ventures, stand-alone projects and other transactions. If we are unable to pursue such other attractive business opportunities, our growth prospects and the long-term strategic position of our businesses following the Merger could be adversely affected. See Item 1, " – Proposed Merger".

Our existing unitholders will be diluted by the Merger.

The Merger will dilute the ownership position of our existing unitholders. Pursuant to the Merger Agreement, PVG unitholders will receive approximately 38.3 million of our limited partner common units as a result of the Merger. Immediately following the Merger, we will be owned approximately 46% by our current unitholders and approximately 54% by former PVG unitholders.

The number of our outstanding limited partner common units will increase as a result of the Merger, which could make it more difficult to pay the current level of quarterly distributions.

As of February 22, 2011, there were approximately 52.3 million of our limited partner common units outstanding. Pursuant to the Merger Agreement, we will issue, and PVG unitholders will receive, approximately 38.3 million of our limited partner common units. Accordingly, as a result of the Merger, the dollar amount required to pay the current per unit quarterly distributions will increase, which will increase the likelihood that we will not have sufficient funds to pay the current level of quarterly distributions to all of our unitholders. Using the amount of $0.47 per Partnership common unit paid on February 14, 2011 with respect to the fourth quarter of 2010, the aggregate cash distribution paid with respect to Partnership common units owned by our unitholders other than PVG totaled approximately $15.3 million. We distributed approximately $15.8 million to PVG for its approximately 19.6 million Partnership common units, the general partner interest in the Partnership and incentive distribution rights in the Partnership. Therefore, including distributions on phantom units of approximately $46,000, our combined total distribution paid with respect to the fourth quarter of 2010 was approximately $31.2 million. The combined pro forma Partnership distribution with respect to the fourth quarter 2010, had the Merger been completed prior to such distribution, would result in $0.47 per unit being distributed on approximately 70.9 million Partnership common units, or a total of approximately $33.3 million, with the Partnership GP no longer receiving any distributions. Including distributions on phantom units of approximately $46,000, our combined pro forma distribution would be approximately $33.4 million. As a result, we would be required to distribute approximately an additional $2.2 million per quarter in order to maintain the distribution level of $0.47 per the Partnership Common Unit paid with respect to the fourth quarter of 2010.

Although the elimination of the incentive distribution rights may increase the cash available for distribution to our limited partner common units in the future, this source of funds may not be sufficient to meet the overall increase in cash required to maintain the current level of quarterly distributions to our unitholders.

Failure to complete the Merger or delays in completing the Merger could negatively impact our limited partner common unit price.

If the Merger is not completed for any reason, we may be subject to a number of material risks, including the following:

- we will not realize the benefits expected from the Merger, including a potentially enhanced financial and competitive position;
- the price of our limited partner common units may decline to the extent that the current market price of these securities reflects a market assumption that the Merger will be completed; and
- some costs relating to the Merger, such as certain investment banking fees and legal and accounting fees, must be paid even if the Merger is not completed.

The costs of the Merger could adversely affect our operations and cash flows available for distribution to our unitholders.

We and PVG estimate the total costs of the Merger to be approximately $10.5 million, primarily consisting of investment banking, legal counsel and accounting fees, financial printing and other related costs. These costs could adversely affect our operations and cash flows available for distributions to our unitholders. The foregoing estimate is preliminary and is subject to change.

Tax Risks Related to the Potential Merger

No ruling has been obtained with respect to the U.S. federal income tax consequences of the Merger.

No ruling has been or will be requested from the IRS with respect to the U.S. federal income tax consequences of the Merger. Instead, we are relying on the opinion of our counsel, and PVG is relying on the opinion of counsel to its Conflicts Committee, as to the U.S. federal income tax consequences of the Merger to our unitholders and PVG unitholders, respectively. These opinions and positions may not be sustained if challenged by the IRS, which could result in a material change to the expected tax consequences of the Merger.

The intended U.S. federal income tax consequences of the Merger are dependent upon each of us and PVG being treated as a partnership for U.S. federal income tax purposes.

The treatment of the Merger as nontaxable to our unitholders and to PVG unitholders is dependent upon each of us and PVG being treated as a partnership for U.S. federal income tax purposes. If either we or PVG were treated as a corporation for U.S. federal income tax purposes, the consequences of the Merger would be materially different and the Merger would be treated as a taxable exchange in which gain or loss would be recognized by the PVG unitholders.

The U.S. federal income tax treatment of the Merger is subject to potential legislative changes and differing judicial or administrative interpretations.

The U.S. federal income tax consequences of the Merger depend on determinations of fact and interpretations of complex provisions of U.S. federal income tax law. The U.S. federal income tax rules are constantly under review by persons involved in the legislative process, the IRS and the U.S. Treasury Department, frequently resulting in revised interpretations of established concepts, statutory changes, revisions to Treasury Regulations and other modifications and interpretations. Any modification to the U.S. federal income tax laws or interpretations thereof may or may not be applied retroactively and could change the U.S. federal income tax treatment of the Merger to our unitholders and PVG's unitholders. For example, the U.S. House of Representatives has passed legislation relating to the taxation of "carried interests" that may treat transactions, such as the Merger, occurring on or after an effective date of January 1, 2011, as a taxable exchange to a unitholder of a partnership such as PVG. The U.S. Senate has considered legislation that may have a similar effect. We and PVG are unable to predict whether this proposed legislation or any other proposals will ultimately be enacted, and if so, whether any such proposed legislation would be applied retroactively.

Tax Risks to Our Existing Unitholders Related to the Potential Merger

An existing unitholder of our limited partner common units may be required to recognize gain as a result of the Merger.

Although it is anticipated that for U.S. federal income tax purposes no gain or loss should be recognized by our existing unitholders solely as a result of the Merger, an existing unitholder may realize gain or loss resulting from (i) a decrease in such unitholder's share of partnership liabilities pursuant to Section 752 of the Code, and (ii) amounts paid to or on behalf of us by another person pursuant to the Merger Agreement.

We estimate that the Merger will result in a relatively small increase in the amount of net income (or decrease in the amount of net loss) allocable to all of our existing unitholders.

We estimate that the closing of the Merger will result in a relatively small increase in the amount of net income (or decrease in the amount of net loss) allocable to all of our existing unitholders. Although we have projected a maximum amount of such an impact for our existing unitholders, the actual amount and effect of such increase in net income (or decrease in net loss) for any Partnership unitholder may be more than anticipated because it will depend upon the unitholder's particular situation, including when, and at what prices, the unitholder purchased our common units and the ability of the unitholder to utilize any suspended passive losses. In addition, the projections are based upon numerous assumptions, and the federal income tax liability of such unitholders could be further increased if we make a future offering of our common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to our assets.

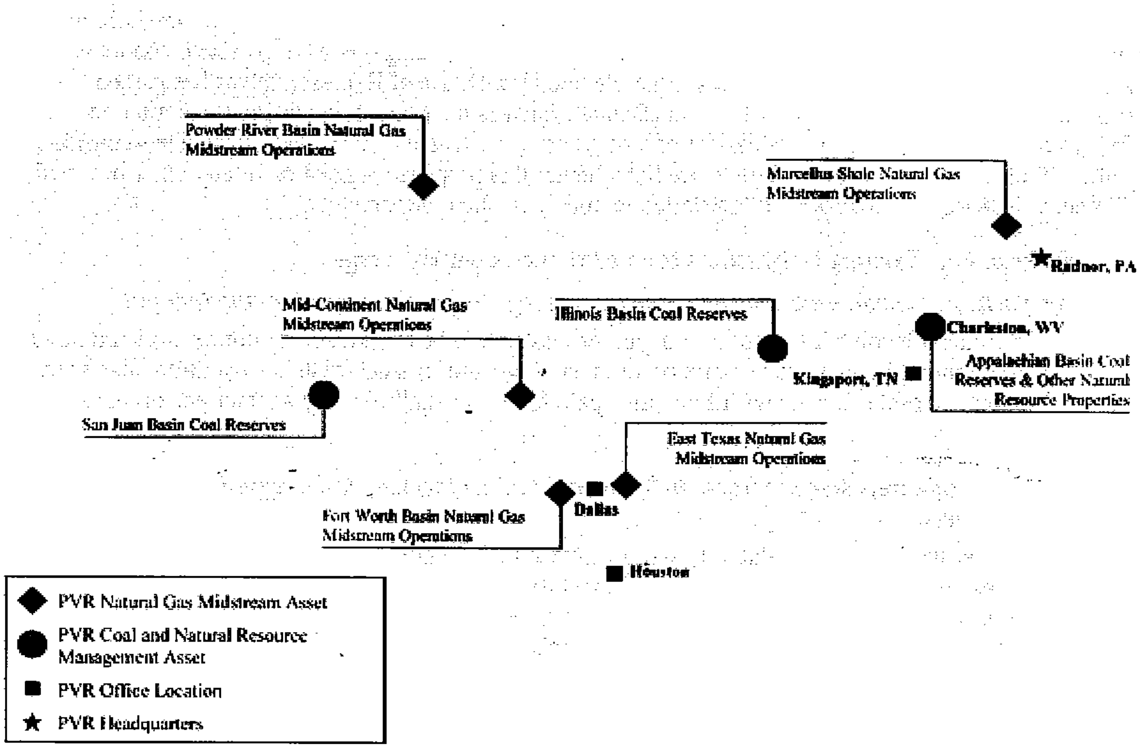
Item 1B Unresolved Staff Comments

None.

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, 2010:



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

We currently lease our office space in Radnor, Pennsylvania, Dallas and Houston, Texas as well as Kingsport, Tennessee. We own the field office in Charleston, West Virginia. We believe that our properties are adequate for our current needs.

Coal Reserves and Production

As of December 31, 2010, we owned or controlled approximately 804 million tons of proven and probable coal reserves located 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 coal reserves are defined as follows:

Proven Coal Reserves. Proven coal 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 Coal Reserves. Probable coal 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 coal 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 to a lesser extent metallurgical market.

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

Our lessees mine coal using both underground and surface methods. As of December 31, 2010, our lessees operated 28 surface mines and 39 underground mines. Approximately 46% of the coal produced from our properties in 2010 came from underground mines and 54% came from surface mines. Most of our lessees use the continuous mining method in 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.

One of our lessees uses the longwall mining method at two different mines 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 in West Virginia 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 tables set forth production data for the periods presented and reserve information with respect to each of our properties for the period presented (tons in millions):

	Production for Year Ended December 31,		
Property	2010	2009	2008
Central Appalachia	18.2	18.3	19.6
Northern Appalachia	4.0	3.8	3.6
Illinois Basin	4.2	4.7	4.6
San Juan Basin	8.1	7.5	5.9
Total	34.5	34.3	33.7

	Proven and Probable Reserves as of December 31, 2010					
Property	Underground	Surface	Total	Steam	Metallurgical	Total
Central Appalachia	429.2	154.3	583.5	500.1	83.4	583.5
Northern Appalachia	29.7	-	29.7	29.7	-	29.7
Illinois Basin	152.7	8.5	161.2	161.2	-	161.2
San Juan Basin	-	29.3	29.3	29.3	-	29.3
Total	611.6	192.1	803.7	720.3	83.4	803.7

Of the approximately 804 million tons of proven and probable coal reserves to which we had rights as of December 31, 2010, we owned the mineral interests and the related surface rights to 432 million tons, or 54%, and we owned only the mineral interests to 190 million tons, or 23%. We leased the mineral rights to the remaining 182 million tons, or 23%, 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 2010, our aggregate expenses to third-party surface and mineral owners were $7.7 million.

The following table sets forth the coal reserves we owned and leased with respect to each of our coal properties as of December 31, 2010 (tons in millions):

Property	Owned	Leased	Total Controlled
Central Appalachia	435.7	147.8	583.5
Northern Appalachia	29.7	-	29.7
Illinois Basin	130.8	30.4	161.2
San Juan Basin	25.4	3.9	29.3
Total	621.6	182.1	803.7

The following table sets forth our coal reserve activity for the periods presented and ended (tons in millions):

	2010	2009	2008
Reserves - beginning of year	828.6	826.8	818.4
Purchase of coal reserves	11.4	2.4	34.6
Tons mined by lessees	(34.5)	(34.3)	(33.7)
Revisions of estimates and other	(1.8)	33.7	7.5
Reserves - end of year (1)	803.7	828.6	826.8

(1) See Item 8, "Financial Statements and Supplementary Data — Note 20. Subsequent Event" for a discussion of a recent purchase of coal reserves.

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, 2010, approximately 24% of our reserves met compliance standards for the CAA and 36% 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 for the period presented (tons in millions):

		Sulfur Content					Typical Clean Coal Quality		
		Reserves as of December 31, 2010					Heat Content		
Property	Compliance (1)	Low Sulfur (2)	Medium Sulfur	High Sulfur	Sulfur Unclassified	Total	BTU per Pound (3)	Sulfur (%)	Ash (%)
Central Appalachia	193.3	265.6	205.6	104.8	7.5	583.5	14,041	1.04	6.50
Northern Appalachia	-	-	-	29.7	-	29.7	12,900	2.58	8.80
Illinois Basin	-	-	-	161.2	-	161.2	11,034	2.39	8.32
San Juan Basin	-	20.0	7.6	1.7	-	29.3	9,200	0.89	17.80
Total	193.3	285.6	213.2	297.4	7.5	803.7			

(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 leased to mine operators by property for the period presented (tons in millions):

	Proven and Probable Reserves As of December 31, 2010		
Property	**Total Controlled**	**Leased to Operators**	**Percentage Leased**
Central Appalachia	583.5	504.5	86%
Northern Appalachia	29.7	19.3	65%
Illinois Basin	161.2	104.4	65%
San Juan Basin	29.3	29.3	100%
Total	803.7	657.5	82%

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 243,000 acres of forestland in Kentucky, Virginia and West Virginia. The majority of our forestland is located on properties that also contain our coal reserves.

We own royalty interests in approximately 6.3 Bcfe of proved oil and gas reserves located in Kentucky, Virginia and West Virginia.

Natural Gas Midstream Systems

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. 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 owned six natural gas processing facilities having 400 MMcfd of total capacity as of December 31, 2010. Our natural gas midstream operations currently include four natural gas gathering and processing systems and three stand-alone natural gas gathering systems, including: (i) the Panhandle gathering and processing facilities in the Texas/Oklahoma panhandle area; (ii) the Crossroads gathering and processing facilities in East Texas; (iii) the Crescent gathering and processing facilities in central Oklahoma; (iv) the Arkoma gathering system in eastern Oklahoma; (v) the North Texas gathering and pipeline facilities in the Fort Worth Basin; (vi) the Hamlin gathering and processing facilities in west-central Texas; (vii) the Marcellus gathering system located in northern Pennsylvania. These assets included approximately 4,263 miles of natural gas gathering pipelines as of December 31, 2010. In addition, we own a 25% member interest in Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. We also own a 50% member interest in Crosspoint, a joint venture that gathers residue gas from our Crossroads Plant and transports it to market.

Panhandle System

General. The Panhandle 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 1,817 miles of natural gas gathering pipelines, ranging in size from two to 16 inches in diameter, and the Beaver, Spearman and Sweetwater natural gas processing plants. Included in the system is an 11-mile, 10-inch diameter, FERC-jurisdictional residue line.

In July 2009, we completed an acquisition of a natural gas processing and residue pipeline facilities in western Oklahoma for approximately $22.6 million in cash. The acquired assets included a 60 MMcfd gas processing plant located near Sweetwater, Oklahoma (the "Sweetwater" plant). Additionally, we completed a 40 MMcfd processing plant expansion in our Spearman complex that was put into service on July 31, 2009. The acquired and expanded processing facilities increased our processing capacity in the Panhandle System to 260 MMcfd. The increased processing capacity has allowed us to process gas volumes that were previously being bypassed due to processing capacity constraints in the Panhandle System and has alleviated pipeline pressure-related volume constraints in the eastern portion of the Panhandle System.

The Panhandle System is comprised of a number of major gathering systems and 30 compressor stations that gather natural gas, directly or indirectly, to the Beaver, Spearman and Sweetwater plants. These include the Beaver, Perryton, Spearman, Wolf Creek/Kiowa Creek and Ellis systems. These gathering systems are located in Beaver, Ellis, Harper and Roger Mills Counties in Oklahoma and Hansford, Hemphill, Hutchinson, Lipscomb, Ochiltree, Roberts and Wheeler Counties in Texas.

The Beaver 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 of up to 16 hours per day.

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

The Sweetwater plant is capable of operating in high ethane recovery mode or in ethane rejection mode and has instrumentation allowing for unattended operation of up to 16 hours per day.

Natural Gas Supply and 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 is delivered into ONG, Natural Gas Pipeline and or ANR pipelines for sale or transportation to market. The NGLs produced at the Spearman plant are 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.

The residue gas from the Sweetwater plant is delivered into Northern Natural Gas pipelines for sale or transportation to market. The NGLs produced at the Sweetwater plant are delivered into ONEOK Hydrocarbon's pipeline system for transportation to and fractionation at ONEOK's Conway fractionator.

Crossroads System

General. The Crossroads System is a natural gas gathering system located in east Texas. The Crossroads System consists of approximately eight miles of natural gas gathering pipelines, ranging in size from eight to twelve inches in diameter, and the Crossroads plant. The Crossroads System also includes approximately 20 miles of six-inch NGL pipeline that transports the NGLs produced at the Crossroads plant to the Panola Pipeline.

The Crossroads plant has 80 MMcfd of inlet capacity. The plant is capable of operating in high ethane recovery mode or in ethane rejection mode and has instrumentation allowing for unattended operation of up to 16 hours per day.

Natural Gas Supply and Markets for Sale of Natural Gas and NGLs. The Crossroads System delivers 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 are delivered into the Panola Pipeline for transportation to Mont Belvieu, Texas 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 1,705 miles of natural gas gathering pipelines, ranging in size from two to 10 inches in diameter, and the Crescent natural 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 and Markets for Sale of Natural Gas and NGLs. 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 Crescent plant's connection to the Enogex and ONEOK Gas Transportation pipelines for residue gas and the ONEOK Hydrocarbon pipeline for NGLs gives 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 517 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 and Markets for Sale of Natural Gas and NGLs. The gas on the Hamlin System is primarily gas associated with the production of oil or "casinghead gas." 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.

North Texas System

General. The North Texas assets are located in the southern portion of the Fort Worth Basin of North Texas and include approximately 136 miles of gas gathering pipelines and approximately 240,000 acres dedicated by active producers. This expands the geographic scope of the natural gas midstream segment into the Barnett Shale play in the Fort Worth Basin.

Natural Gas Supply. The gathering and transportation infrastructure captures current and expected volumes in Johnson, Hill, Bosque, Somervell, Hamilton and Erath counties.

Marcellus System

General. The Marcellus assets are located in Wyoming and Lycoming Counties in Pennsylvania. We have currently completed construction of three miles of 12-inch gas gathering pipelines in Wyoming County and began gathering natural gas in June 2010. Construction and development to provide gathering, compression and related services in Lycoming County continues and the first segment of the system began operations in February 2011.

Natural Gas Supply. The gathering and transportation infrastructure captures current and expected volumes in the Marcellus Shale area. The Marcellus System delivers the natural gas to local customers as well providing avenues for local producers to major pipeline systems such as Transco.

Item 3 Legal Proceedings

As previously disclosed in the joint proxy statement/prospectus of the Partnership and PVG filed with the Securities and Exchange Commission on December 23, 2010 (the "Joint Proxy Statement/Prospectus"), Kevin Epoch, Sanjay Israni and Anita Scheifele, purported PVG unitholders, (collectively, "Plaintiffs") filed various putative class action complaints, subsequently amended, against the Partnership, PVR GP, PVG, PVG GP, and certain of PVG GP's directors and officers (collectively, "Defendants") in the Court of Common Pleas of Delaware County, Pennsylvania under the captions Epoch v. Penn Virginia GP Holdings, L.P., et al. and Scheifele v. Shea, et al. relating to the Merger Agreement and the related Merger transactions.

On February 1, 2011, the parties to the above-described Epoch and Scheifele actions entered into the Memorandum of Understanding ("MOU") to settle the litigation in its entirety. The MOU provides that the parties will seek dismissal with prejudice of the litigation and a release of the Defendants from all present and future claims asserted in the litigation in exchange for a supplemental disclosure to the Joint Proxy Statement/Prospectus. The supplemental disclosure is set forth in a Joint Proxy Statement/Prospectus supplement filed with the Securities and Exchange Commission on February 3, 2011.

The MOU is subject to a number of conditions, including, without limitation, completion of certain discovery by the plaintiffs, the drafting and execution of a formal Stipulation of Settlement, the consummation of the merger and court approval of the proposed settlement. There is no assurance that these conditions will be satisfied.

Other than the merger-related litigation described above, 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 Reserved

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) and distributions declared related to each fiscal quarter in 2010 and 2009 were as follows:

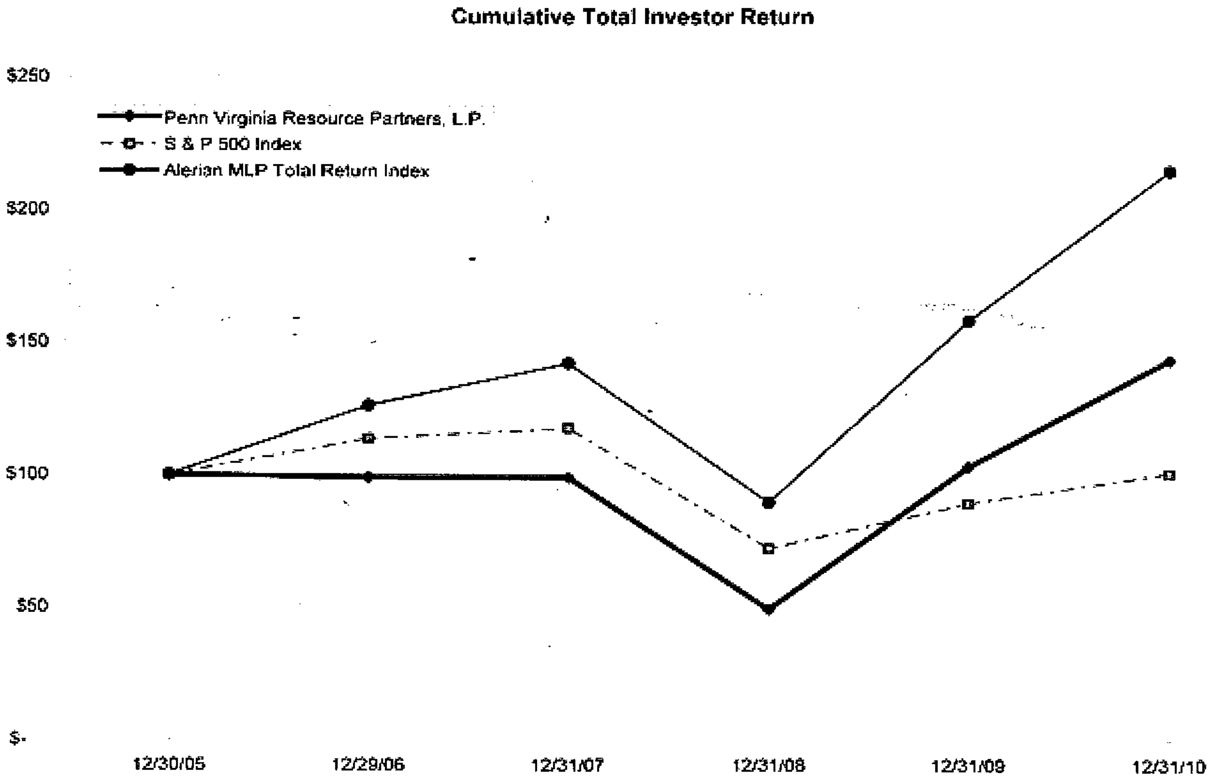
Quarter Ended	High	Low	Cash Distribution Declared
December 31, 2010	$29.11	$24.78	$0.47
September 30, 2010	$25.00	$20.26	$0.47
June 30, 2010	$24.75	$10.01	$0.47
March 31, 2010	$24.93	$19.63	$0.47
December 31, 2009	$22.30	$16.57	$0.47
September 30, 2009	$17.98	$12.35	$0.47
June 30, 2009	$15.99	$10.96	$0.47
March 31, 2009	$16.51	$9.10	$0.47

Equity Holders

As of December 31, 2010, there were 178 record holders and approximately 37,800 beneficial owners of our common units.

Common Unitholder Return Performance Presentation

The performance graph below compares the cumulative total unitholder return on our common units with the cumulative total returns on the Standard & Poor's 500 Index (the "S&P 500 Index") and the Alerian MLP Total Return Index (the "Alerian Total Return Index"). The Alerian Total Return Index is a composite of the 50 most prominent energy master limited partnerships and limited liability companies, as determined by Standard & Poor's using a float-adjusted market capitalization methodology. The graph assumes an investment of $100 in our common units, and in each of the S&P 500 Index and the Alerian Total Return Index on December 30, 2005 and reinvestment of all dividends and distributions. The results shown in the graph are based on historical data and should not be considered indicative of future performance.



	12/30/2005	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
Penn Virginia Resource Partners, L.P.	100.0	98.6	99.0	49.4	103.1	143.5
S& P 500 Index	100.0	113.6	117.6	72.4	89.3	100.7
Alerian MLP Total Return Index	100.0	126.1	142.1	89.6	158.1	214.9

Notwithstanding anything to the contrary set forth in any of our previous or future filings under the Securities Act of 1933 or the Securities Exchange Act of 1934 that might incorporate this report or future filings with the SEC, in whole or in part, the preceding performance information shall not be deemed to be "soliciting material" or to be "filed" with the SEC or incorporated by reference into any filing except to the extent this performance presentation is specifically incorporated by reference therein.

Item 6 Selected Financial Data

The following selected historical financial information was derived from our Consolidated Financial Statements as of December 31, 2010, 2009, 2008, 2007 and 2006, 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 and Supplementary Data in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data":

	2010	2009	2008	2007	2006
	(in thousands, except per unit data)				
Statement of Income Data:					
Revenues (1)	$ 864,136	$ 656,704	$ 881,580	$ 549,445	$ 517,891
Expenses (1)	$ 738,237	$ 548,402	$ 766,338	$ 431,720	$ 415,071
Operating income	$ 125,899	$ 108,302	$ 115,242	$ 117,725	$ 102,820
Net income	$ 68,458	$ 65,215	$ 104,500	$ 56,623	$ 73,928
Common Unit Data:					
Net income per limited partner unit, basic and diluted	$ 0.83	$ 0.76	$ 1.63	$ 0.92	$ 1.59
Distributions paid	$ 124,595	$ 124,009	$ 111,076	$ 89,649	$ 66,954
Distributions paid per unit	$ 1.88	$ 1.88	$ 1.82	$ 1.66	$ 1.48
Balance Sheet and Other Financial Data:					
Property, plant and equipment, net	$ 971,046	$ 900,844	$ 895,119	$ 731,282	$ 556,513
Total assets (2)	$ 1,297,501	$ 1,208,060	$ 1,218,819	$ 931,279	$ 714,023
Long-term debt	$ 708,000	$ 620,100	$ 568,100	$ 399,153	$ 207,214
Cash flows provided by operating activities	$ 183,696	$ 159,972	$ 139,176	$ 127,824	$ 107,344
Additions to property, plant and equipment	$ 124,116	$ 80,677	$ 332,028	$ 225,040	$ 129,712
Other Statistical Data:					
Coal royalty tons (in thousands)	34,512	34,330	33,690	32,528	32,778
System throughput volumes (MMcf)	129,703	121,335	98,683	67,810	55,991

(1) In 2010, 2009 and 2008, we recorded $27.8 million, $72.5 million and $127.9 million of natural gas midstream revenue and $27.8 million, $72.5million and $127.9 million for the cost of midstream gas purchased related to the purchase of natural gas from PVOG LP, a subsidiary of Penn Virginia Corporation and considered a related party company up to June 7, 2010, and the subsequent sale of that gas to third parties. We took title to the gas prior to transporting it to third parties. These transactions do not impact the gross margin, nor do they impact operating income.

(2) Total assets for the year ended December 31, 2008 include PVR's Lone Star acquisition, which expanded the geographic scope of the PVR natural gas midstream segment into the Barnett Shale play in the Fort Worth Basin. See Note 3 to the Consolidated Financial Statements for a more detailed description of this acquisition, including pro forma results.

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 (the "Partnership," "we," "us" or "our") should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8. All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated.

Overview of Business

We are a publicly traded Delaware limited partnership formed 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: (i) coal and natural resource management and (ii) natural gas midstream. In 2010, our coal and natural resource management segment contributed $93.1 million, or 74%, to operating income, and our natural gas midstream segment contributed $32.8 million, or 26%, to operating income.

Coal and Natural Resource Segment

As of December 31, 2010, we owned or controlled approximately 804 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. 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 2010, our lessees produced 34.5 million tons of coal from our properties and paid us coal royalties revenues of $130.3 million, for an average royalty per ton of $3.78. Approximately 80% of our coal royalties revenues in 2010 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.

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 lessees' 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 over an extended period of time, our average royalty per ton may change as the majority of our lessees pay royalties based on the gross sales prices of the coal mined. However, most of our lessees' coal is sold under contracts with a duration of one year or more; therefore, the underlying prices for our royalties are less susceptible to short-term volatility in coal prices and prices change primarily as our lessees' long-term contracts are renegotiated.

We also earn revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage, fees.

Natural Gas Midstream Segment

Our natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. As of December 31, 2010, we owned and operated natural gas midstream assets located in Oklahoma, Pennsylvania and Texas, including six natural gas processing facilities having 400 MMcfd of total capacity and approximately 4,263 miles of natural gas gathering pipelines. Our natural gas midstream business earns revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. In addition, we own a 25% member interest in Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. We own a 50% member interest in Crosspoint, a joint venture that gathers residue gas from our Crossroads Plant and transports it to market. 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.

In 2010, system throughput volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 129.7 Bcf, or approximately 355 MMcfd. In 2010, 17%, 14%, 11% and 10% of our natural gas midstream segment revenues and 14%, 11%, 9% and 8% of our total consolidated revenues resulted from four of our natural gas midstream customers, Conoco Phillips Company, Tenaska Marketing Ventures, Targa Liquids Marketing and Trade and Williams NGL Marketing, LLC.

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. In 2010, our natural gas midstream segment made aggregate capital expenditures of $104.5 million, primarily related to our expansion of the Panhandle System and Marcellus System due to growth opportunities in those areas. For a more detailed discussion of our acquisitions and investments, see "— Acquisitions and Investments."

Key Developments

2010 Commodity Prices

The 2010 average commodity prices for coal, timber, natural gas, crude oil and NGLs increased from 2009 levels. NGLs refer to ethane, propane, iso butane, normal butane and pentane. The pricing of these commodities directly and indirectly drive our earnings.

Coal royalties, which accounted for 85% of the 2010 coal and natural resource management segment revenues, were eight percent higher as compared 2009. The increase was attributed to higher realized coal royalties per ton by region. Coal prices received by our lessees increased during 2010 as compared to 2009. Due to global demands and production issues, the most noticeable increase related to the sales price of metallurgical coal. Coal operators in the Appalachian Basin realized higher prices for metallurgical coal and sought ways to increase production.

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. 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 demand. As part of our risk management strategy, we use derivative financial instruments to economically hedge NGLs sold and natural gas purchased. Our derivative financial instruments include costless collars and swaps. Based upon current volumes, we have entered into hedging arrangements covering approximately 55% and 32% of our commodity-sensitive volumes in 2011 and 2012. Historically, we have targeted hedging 50% to 60% of our commodity-sensitive volumes covering a two-year period.

Acquisitions and Investments

In June 2010, we completed and began operating a natural gas gathering pipeline and compression facilities servicing a private firm's Marcellus Shale natural gas production in Wyoming County, Pennsylvania. Construction and development of other gathering and compression facilities in other areas of the Marcellus Shale play are in progress. The facilities will provide gathering, compression and related services in Lycoming County and the first segment of the system began operations in February 2011.

We had two coal mineral acquisitions during 2010. We acquired approximately 10 million tons of Pittsburgh Seam coal reserves for $17.7 million in cash. This transaction supplements 40 million tons that we previously acquired in December 2002. In addition to the acquisition of the reserves, we received an increase in royalty of $1.00 per ton for the approximate 10 million tons of coal reserves remaining on the original transaction, plus a royalty on the newly-acquired reserves. In December, we purchased coal reserves in a greenfield project in Northern Appalachia. Our initial investment is $7 million in cash with contingency payments to be made as permitting and production progress.

In December 2010, we announced a definitive agreement to purchase certain mineral rights and associated oil and gas royalty interests in Kentucky and Tennessee for approximately $97.3 million, subject to closing adjustments. The mineral rights include approximately 102 million tons of coal reserves and resources, and royalty interest from approximately 158 oil and gas wells. There are currently 14 active producing underground and surface mines on the approximately 126,000 acres of mineral estates being acquired, with 10 principal coal lessees operating the mines. The coal is primarily steam coal that is consumed by major electric utilities and other industrial customers in the southeastern United States. On January 25, 2011 we completed the purchase of these assets.

Changes in Our Management

In connection with Penn Virginia's (Penn Virginia Corporation NYSE: PVA) reduction of its limited partner interest in Penn Virginia GP Holdings, L.P., or PVG, we implemented certain changes in management, as a result of which certain executive officers of Penn Virginia resigned as executive officers and directors of Penn Virginia Resource GP, LLC, or PVR GP, our general partner.

On March 8, 2010, A. James Dearlove resigned from his position as Chief Executive Officer of PVR GP, and on March 9, 2010, he resigned from his position as President and Chief Executive Officer of PVG GP, LLC, or PVG GP, the general partner of PVG. On March 8, 2010, the board of directors of PVR GP appointed William H. Shea, Jr. to the position of Chief Executive Officer of PVR GP, and on March 9, 2010 the board of directors of PVG GP appointed Mr. Shea to the positions of President and Chief Executive Officer of PVG GP.

On March 23, 2010, Frank A. Pici resigned from his position as Vice President and Chief Financial Officer of PVR GP, and his position as Vice President and Chief Financial Officer of PVG GP. On March 23, 2010, the board of directors of PVR GP appointed Robert B. Wallace to the position of Executive Vice President and Chief Financial Officer of PVR GP, and the board of directors of PVG GP appointed Mr. Wallace to the position of Executive Vice President and Chief Financial Officer of PVG GP.

On March 31, 2010, A. James Dearlove, Frank A. Pici and Nancy M. Snyder each resigned from their positions as directors on the board of directors of PVR GP. On March 31, 2010, Mr. Shea was appointed as a director on the board of directors of PVR GP and on the board of directors of PVG GP.

On June 7, 2010, Ms. Snyder resigned from her position as Vice President, Chief Administrative Officer, General Counsel and Assistant Secretary of PVR GP. On June 29, 2010 the board of directors of PVR GP appointed Bruce D. Davis, Jr. as Executive Vice President, General Counsel and Secretary of PVR GP.

Senior Notes Offering

In April 2010, the Company sold $300.0 million of unsecured Senior Notes due on April 15, 2018 with an annual interest rate of 8.25% payable semi-annually in arrears on April 15 and October 15 of each year. The Senior Notes were sold at par, equating to an effective yield to maturity of 8.25%.

Proposed Merger

On September 21, 2010, the Partnership announced that it had entered into an Agreement and Plan of Merger (the "Merger Agreement") by and among the Partnership, PVR GP, PVG, PVG GP, and PVR Radnor, LLC ("Merger Sub"), a wholly owned subsidiary of the Partnership, pursuant to which PVG and PVG GP will be merged into Merger Sub, with Merger Sub as the surviving entity (the "Merger"). Merger Sub will subsequently be merged into our general partner, PVR GP, with PVR GP being the surviving entity. In the transaction, PVG unitholders will receive consideration of 0.98 common units in the Partnership for each common unit in PVG representing aggregate consideration of approximately 38.3 million common units in the Partnership. Pursuant to the Merger Agreement and the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, the incentive distribution rights held by our general partner will be extinguished, the 2.0% general partner interest in the Partnership held by our general partner will be converted into a noneconomic interest and approximately 19.6 million common units in the Partnership owned by PVG will be cancelled.

The terms of the Merger Agreement were unanimously approved by our conflicts committee, comprised of independent directors, of the board of directors of our general partner, by the board of directors of our general partner, by the PVG conflicts committee, comprised of independent directors, of the board of directors of PVG's general partner, and by the board of directors of PVG's general partner (in each case with the chief executive officer of each general partner recusing himself from the board of directors approvals).

Pursuant to the Merger Agreement, PVG agreed to support the Merger by, among other things, voting its Partnership common units in favor of the Merger and against any transaction that, among other things, would materially delay or prevent the consummation of the Merger. The agreement to support automatically terminates if the conflicts committee of the board of directors or the board of directors of the general partner of PVG changes its recommendation to PVG's unitholders with respect to the Merger or the conflicts committee of the board of directors or the board of directors of our general partner changes its recommendation to the Partnership's unitholders with respect to the Merger.

After the Merger, the board of directors of our general partner, PVR GP, is expected to consist of nine members, six of whom are expected to be the existing members of the board and three of whom are expected to be the three existing members of the conflicts committee of the board of directors of PVG's general partner.

The Merger Agreement is subject to customary closing conditions including, among other things, (i) approval by the affirmative vote of the holders of a majority of our common units outstanding and entitled to vote at a meeting of the holders of our common units, (ii) approval by the affirmative vote of the holders of a majority of PVG's common units outstanding and entitled to vote at a meeting of the holders of PVG's common units, (iii) receipt of applicable regulatory approvals, (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance of our common units in connection with the Merger, (v) receipt of certain tax opinions, (vi) approval for listing our common units to be issued in connection with the Merger on the New York Stock Exchange and (vii) the execution of our Fourth Amended and Restated Agreement of Limited Partnership.

Current holders of our common units (the "Partnership unitholders") will continue to own their existing Partnership common units. Following the Merger, we will be owned approximately 46% by current Partnership unitholders and approximately 54% by former PVG unitholders. Our common units will continue to be traded on the New York Stock Exchange under the symbol "PVR" following the Merger.

PVG will be considered the surviving consolidated entity for accounting purposes, while we will be the surviving consolidated entity for legal and reporting purposes. The Merger will be accounted for as an equity transaction. Therefore, the changes in PVG's ownership interest as a result of the Merger will not result in gain or loss recognition.

On February 16, 2011, the Partnership held a special meeting to consider the vote upon the approval and adoption of the Merger and the other transactions contemplated by the Merger Agreement. At the special meeting, two matters were voted on and approved by a majority of the Partnership's unitholders. The first matter voted upon was the approval of the

Merger Agreement and the transactions contemplated thereby. 67.52% or 35,308,687 of the Partnership's units outstanding and entitled to vote, voted in favor of this matter. The second matter voted upon was the approval of the Fourth Amended and Restated Partnership Agreement. 67.54% or 35,322,534 of the Partnership's units outstanding and entitled to vote, voted in favor of this matter.

On February 16, 2011, PVG announced that it had adjourned its special meeting of PVG unitholders originally scheduled for February 16, 2011 until March 9, 2011. Prior to the adjournment of the PVG special meeting, 20,688,419 units, or 52.94% of the PVG units outstanding and entitled to vote, voted in favor of the proposal to adjourn the special meeting to a later date to allow further time to solicit additional proxies from PVG unitholders. At the commencement of the PVG special meeting, the proxies received from unitholders totaled 25,353,727 million units, or 64.88% of all PVG units outstanding and entitled to vote. Of the total PVG units outstanding and entitled to vote, proxies representing 39.77% of the PVG units were in favor of the merger proposal. The approval of the Merger Agreement and related transactions requires the affirmative vote of holders of a majority of all units outstanding and entitled to vote. The reconvened PVG special meeting will be held at The Villanova University Conference Center, 601 County Line Road, Radnor, Pennsylvania 19087 on March 9, 2011 at 10:00 AM local time.

Liquidity and Capital Resources

Cash Flows

On an ongoing basis, we generally satisfy our working capital requirements and fund our capital expenditures using cash generated from our operations, borrowings under the Revolver and proceeds from debt and equity offerings. We satisfy our debt service obligations and distributions to unitholders solely using cash generated from our operations. We believe that the cash generated from our operations and our borrowing capacity will be sufficient to meet our 2011 working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distributions. However, our ability to meet these requirements in the future will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry and natural gas midstream market, some of which are beyond our control. If our plans or assumptions change or are inaccurate, or we make acquisitions, we may need to raise additional capital. While global financial markets and economic conditions have been disrupted in the past, these conditions have improved more recently. However, we can give no assurance that we can raise additional capital in a cost-effective manner to meet these needs.

The following table summarizes our statements of cash flows for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Cash flows from operating activities:			
Net income	$ 68,458	$ 65,215	$ 104,500
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	103,241	100,065	41,205
Net changes in operating assets and liabilities	11,997	(5,308)	(6,529)
Net cash provided by operating activities	183,696	159,972	139,176
Net cash used in investing activities	(122,787)	(79,530)	(331,030)
Net cash used in financing activities	(58,917)	(81,267)	181,808
Net increase (decrease) in cash and cash equivalents	$ 1,992	$ (825)	$ (10,046)

Cash Flows From Operating Activities

The overall increase in net cash provided by operating activities in 2010 as compared to 2009 was primarily driven by an increase in the natural gas midstream segment's gross margin and higher coal royalties revenue. These increases were offset by cash derivative settlements, and higher operating and general and administrative costs, which were incurred as result of expanding operations and change in management structure.

The overall increase in net cash provided by operating activities in 2009 as compared to 2008 was driven by an increase in the natural gas midstream segment's gross margin, adjusted for the cash impact of midstream derivatives and impairments. We received a net $10.6 million in midstream derivative settlements in 2009 compared to paying a net $37.2 million in 2008. The difference in net derivative settlements relates to decreased commodity pricing and the expiration of older commodity derivatives. This increase in cash flows was partially offset by a decrease in operating income, before DD&A expense and impairments from the coal and natural resource management segment primarily due to decreases in coal royalties, oil and gas royalties and other revenue.

Cash Flows From Investing Activities

Net cash used in investing activities were primarily for capital expenditures. The following table sets forth our capital expenditures programs, by segment, for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Coal and natural resource management			
Acquisitions	$ 27,641	$ 2,067	$ 27,075
Other property and equipment expenditures	1,170	185	195
Total	28,811	2,252	27,270
Natural gas midstream			
Acquisitions	-	27,514	259,417
Expansion capital expenditures	96,334	36,863	59,385
Other property and equipment expenditures	14,126	8,399	14,505
Total	110,460	72,776	333,307
Total capital expenditures	$ 139,271	$ 75,028	$ 360,577

Our 2010 capital expenditures consisted primarily of natural gas midstream expansion capital used to increase our natural gas gathering and operational footprint in our Panhandle and Marcellus Systems. We also added to our reserve base in Northern Appalachia by amending an existing coal mineral lease and from a coal mineral acquisition. During 2011, we expect to invest approximately $140.0 million in internal growth capital.

Our 2009 capital expenditures consisted primarily of a natural gas midstream plant acquisition, and expansion capital used to increase our natural gas processing capacity and operational footprint in our Panhandle System.

Our 2008 capital expenditures were primarily discretionary in nature and included our 25% member interest acquisition in Thunder Creek, the Lone Star acquisition, pipeline assets in the Anadarko Basin of Oklahoma and Texas, expansion capital expenditures related to the Spearman and Crossroads plants and the acquisition of approximately 29 million tons of coal reserves and an estimated 56 MMbf of hardwood timber in western Virginia and eastern Kentucky. Our natural gas midstream segment also incurred approximately $14.5 million of maintenance capital expenditures for equipment overhauls and connecting wells in existing areas.

Cash Flows From Financing Activities

During 2010, we amended the Revolver to extend the maturity date and increase our borrowing capacity to $850 million. We also issued $300 million of Senior Notes. The net proceeds from the sale of the Senior Notes were used to repay borrowings under the Revolver. Offsetting the repayment were funds drawn to finance our expansion growth capital. During 2009, we had net borrowings of $52.0 million under the Revolver. These borrowings were used to fund our capital expenditure program. During 2008, we had net borrowings of $156.0 million primarily attributable to the Revolver offset by the repayments of $63.3 million under the Senior Unsecured Notes due 2013. In 2008 we also received net proceeds of $141.1 million from the sale of our common units in a public offering, which was comprised of net proceeds of $138.2 million from the sale of the common units to the public and $2.9 million in contributions from our general partner to maintain its 2% general partner interest.

In January 2011 we declared a $0.47 ($1.88 on an annualized basis) per unit quarterly distribution for the three months ended December 31, 2010 paid on February 14, 2011 to unitholders of record at the close of business on February 7, 2011.

Certain Non-GAAP Financial Measures

We use non-GAAP (Generally Accepted Accounting Principles) measures to evaluate our business and performance. None of these measures should be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP, or as indicators of our operating performance or liquidity.

	Year Ended December 31,		
	2010	**2009**	**2008**
Reconciliation of GAAP "Operating income" to Non-GAAP "EBITDA"			
Operating income	$ 125,899	$ 108,302	$ 115,242
Depreciation, depletion and amortization	75,900	70,235	58,166
Impairments	-	1,511	31,801
EBITDA (a)	$ 201,799	$ 180,048	$ 205,209
Reconciliation of GAAP "Net income" to Non-GAAP "Distributable cash flow"			
Net income	$ 68,458	$ 65,215	$ 104,500
Depreciation, depletion and amortization	75,900	70,235	58,166
Impairments	-	1,511	31,801
Commodity derivative contracts:			
Derivative losses included in net income	23,583	22,700	(11,357)
Cash receipts (payments) to settle derivatives for the period	(10,075)	3,000	(38,466)
Equity earnings from joint venture, net of distributions	3,274	(2,537)	(224)
Maintenance capital expenditures	(15,296)	(8,399)	(14,505)
Distributable cash flow (b)	$ 145,844	$ 151,725	$ 129,915
Distribution to Partners:			
Limited partner units	$ 97,889	$ 97,382	$ 89,207
Phantom units (c)	440	499	-
General partner interest	1,999	1,988	1,820
Incentive distribution rights (d)	24,267	24,140	20,049
Total cash distribution paid during period	$ 124,595	$ 124,009	$ 111,076
Total cash distribution paid per unit during period	$ 1.88	$ 1.88	$ 1.82

(a) EBITDA, or earnings before interest, tax and depreciation, depletion and amortization ("DD&A") represents operating income plus DD&A, plus impairments. We believe this presentation is commonly used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of companies in the coal and natural gas midstream industries. We use this information for comparative purposes within the industry. EBITDA is not a measure of financial performance under GAAP and should not be considered as a measure of liquidity or as an alternative to net income.

(b) Distributable cash flow represents net income plus depreciation, depletion and amortization expenses, plus impairments, plus (minus) derivative losses (gains) included in other income, plus (minus) cash received (paid) for derivative settlements, minus equity earnings in joint ventures, plus cash distributions from joint ventures, minus maintenance capital expenditures. Distributable cash flow is a significant liquidity metric which is an indicator of our ability to generate cash flows at a level that can sustain or support an increase in quarterly cash distributions paid to our partners. Distributable cash flow is also the quantitative standard used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of publicly traded partnerships. Distributable cash flow is presented because we believe it is a useful adjunct to net cash provided by operating activities under GAAP. Distributable cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities, as an indicator of cash flows, as a measure of liquidity or as an alternative to net income.

(c) Phantom units grants were made in both 2010 and 2009 under our long-term incentive plan. Phantom units receive distribution rights; thus, we have presented distributions paid to phantom unit holders in our total distributions paid to Partners.

(d) 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.

Distributable cash flow for 2010 of $145.8 million was $5.9 million, or four percent lower, than the $151.7 million of distributable cash flow in 2009 primarily due to:

- $13.1 million increase in cash payments to settle derivatives; and
- $10.9 million increase in interest expense associated with the higher interest bearing Senior Notes; and
- $6.9 million increase in maintenance capital

These decreases in distributable cash flow were partially offset by:

- $21.8 million increase in operating income adjusted for depreciation, depletion and amortization ("DD&A") and impairments for both the coal and midstream segments, due to increased average coal royalties per ton and increased natural gas processing margins.

Sources of Liquidity

Long-Term Debt

Revolver. On August 13, 2010, we entered into an amended and restated secured credit agreement increasing our borrowing capacity under the Revolver to $850.0 million. As of December 31, 2010, net of outstanding indebtedness of $408.0 million and letters of credit of $1.6 million, we had remaining borrowing capacity of $440.4 million on the Revolver. The Revolver matures August 13, 2015. The Revolver includes a $10 million sublimit for the issuance of letters of credit and a $25 million sublimit for swingline borrowings. We have an option, subject to the acceptance by the bank group, to increase the commitments under the Revolver by up to an additional $200 million, to a total of $1.05 billion. The Revolver is available to provide funds for general partnership purposes, including working capital, capital expenditures, acquisitions and quarterly distributions. In 2010, we incurred commitment fees of $1.2 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 base rate plus an applicable margin ranging from 1.25% to 2.25% if we select the base rate indebtedness option under the Revolver or at a rate derived from LIBOR plus an applicable margin ranging from 2.25% to 3.25% if we select the LIBOR-based indebtedness option. The weighted average interest rate on borrowings outstanding under the Revolver during 2010 was approximately 2.5%. We do not have a public rating for the Revolver. As of December 31, 2010, we were in compliance with all of our covenants under the Revolver.

Senior Notes. In April 2010, we sold $300.0 million of Senior Notes due on April 15, 2018 with an annual interest rate of 8.25%, which is payable semi-annually in arrears on April 15 and October 15 of each year. The Senior Notes were sold at par, equating to an effective yield to maturity of approximately 8.25%. The net proceeds from the sale of the Senior Notes of approximately $292.6 million, after deducting fees and expenses of approximately $7.4 million, were used to repay borrowings under the Revolver. The Senior Notes are senior to any subordinated indebtedness, and are effectively subordinated to all of our secured indebtedness including the Revolver to the extent of the collateral securing that indebtedness. The obligations under the Senior Notes are fully and unconditionally guaranteed by our current and future subsidiaries, which are also guarantors under the Revolver.

Interest Rate Swaps. We have entered into interest rate swaps, or Interest Rate Swaps, to establish fixed rates on a portion of the outstanding borrowings under the Revolver. The following table sets forth the Interest Rate Swap positions at December 31, 2010 (in millions):

Term	Notional Amounts (in millions)	Swap Interest Rates Pay	Receive
March 2010 - December 2011	$250.0	3.37%	LIBOR
December 2011 - December 2012	$100.0	2.09%	LIBOR

After considering the applicable margin of 2.50% in effect as of December 31, 2010 the total interest rate on the $250.0 million portion of the Revolver borrowings covered by the Interest Rate Swaps was 5.87% as of December 31, 2010.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2010:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 years
Revolver	$ 408,000	$ -	$ -	408,000	$ -
Senior notes	300,000	-	-	-	300,000
Asset retirement obligations (1)	2,172	-	369	-	1,803
Interest expense (2)	235,654	36,704	73,408	68,823	56,719
Derivatives (3)	24,623	19,516	5,107	-	-
Natural gas midstream activities (4)	26,151	12,628	8,541	4,982	-
Rental commitments (5)	27,436	4,094	8,148	7,853	7,341
Contingency payments (6)	2,765	-	837	1,017	911
Total contractual obligations (7)	$ 1,026,801	$ 72,942	$ 96,410	$ 490,675	$ 366,774

(1) The undiscounted balance was approximately $7.7 million at December 31, 2010.

(2) Represents estimated interest payments that will be due under the Revolver (which matures August 13, 2015) and Senior Notes (which mature April 15, 2018).

(3) Represents estimated payments we will make resulting from our commodity derivatives as well as the Interest Rate Swaps.

(4) Commitments for natural gas midstream activities relate to firm transportation agreements.

(5) Primarily relates to equipment and building leases and leases of coal reserve-based properties which we sublease, or intend to sublease, to third parties.

(6) Part of the purchase price for coal reserves in Northern Applachia includes undiscounted contingency payments of $5.2 million.

(7) Total contractual obligations do not include anticipated 2011 capital expenditures.

Part of the purchase price for the Lone Star acquisition includes contingent payments of approximately $55.0 million. These contingency payments will be made by us if certain revenue targets are met before June 30, 2013. Because the outcome of these contingent payments is not determinable beyond a reasonable doubt, we have not accrued them as a liability. Rather, once the revenue targets are met, the contingent payments will be recorded as an additional cost of the Lone Star acquisition.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2010, the material off-balance sheet arrangements and transactions that we have entered into included operating lease arrangements, firm transportation agreements, and letters of credit, all of which are customary in our business. See Contractual Obligations summarized above for more detail related to the value of off-balance sheet arrangements. 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

Consolidated Review

The following table presents summary consolidated operating results for the periods presented:

	Year Ended December 31, 2010	2009	2008
Revenues	$ 864,136	$ 656,704	$ 881,580
Expenses	738,237	548,402	766,338
Operating income	125,899	108,302	115,242
Other income (expense) (1)	(57,441)	(43,087)	(10,742)
Net income	$ 68,458	$ 65,215	$ 104,500

(1) Other income (expense) includes interest expense, interest income and derivatives.

The following table presents certain summary financial information relating to our segments for the periods presented:

	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
For the Year Ended December 31, 2010:			
Revenues	$ 152,488	$ 711,648	$ 864,136
Cost of gas purchased	-	(577,813)	(577,813)
Operating costs and expenses	(28,483)	(56,041)	(84,524)
Depreciation, depletion and amortization	(30,873)	(45,027)	(75,900)
Operating income	$ 93,132	$ 32,767	$ 125,899
For the Year Ended December 31, 2009:			
Revenues	$ 144,600	$ 512,104	$ 656,704
Cost of gas purchased	-	(406,583)	(406,583)
Operating costs and expenses	(24,231)	(45,842)	(70,073)
Impairments	(1,511)	-	(1,511)
Depreciation, depletion and amortization	(31,330)	(38,905)	(70,235)
Operating income	$ 87,528	$ 20,774	$ 108,302
For the Year Ended December 31, 2008:			
Revenues	$ 153,327	$ 728,253	$ 881,580
Cost of gas purchased	-	(612,530)	(612,530)
Operating costs and expenses	(26,226)	(37,615)	(63,841)
Impairments	-	(31,801)	(31,801)
Depreciation, depletion and amortization	(30,805)	(27,361)	(58,166)
Operating income	$ 96,296	$ 18,946	$ 115,242

Coal and Natural Resource Management Segment

Year Ended December 31, 2010 Compared With Year Ended December 31, 2009

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 periods presented:

	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	% Change
Financial Highlights				
Revenues				
Coal royalties	$ 130,349	$ 120,435	9,914	8%
Coal services	7,830	7,332	498	7%
Timber	6,261	5,726	535	9%
Oil and gas royalty	2,651	2,471	180	7%
Other	5,397	8,636	(3,239)	(38%)
Total revenues	152,488	144,600	7,888	5%
Expenses				
Operating	11,437	9,692	(1,745)	(18%)
General and administrative	17,046	14,539	(2,507)	(17%)
Impairments	-	1,511	1,511	-
Depreciation, depletion and amortization	30,873	31,330	457	1%
Total expenses	59,356	57,072	(2,284)	(4%)
Operating income	93,132	87,528	5,604	6%
Other data				
Coal royalty tons by region				
Central Appalachia	18,207	18,319	(112)	(1%)
Northern Appalachia	3,965	3,786	179	5%
Illinois Basin	4,182	4,724	(542)	(11%)
San Juan Basin	8,158	7,501	657	9%
Total tons	34,512	34,330	182	1%
Coal royalties revenues by region				
Central Appalachia	92,827	85,183	7,644	9%
Northern Appalachia	8,449	6,931	1,518	22%
Illinois Basin	11,208	12,420	(1,212)	(10%)
San Juan Basin	17,865	15,901	1,964	12%
Total royalties	130,349	120,435	9,914	8%
Coal royalties per ton by region ($/ton)				
Central Appalachia	$ 5.10	$ 4.65	$ 0.45	10%
Northern Appalachia	2.13	1.83	0.30	16%
Illinois Basin	2.68	2.63	0.05	2%
San Juan Basin	2.19	2.12	0.07	3%
Average royatlies per ton	$ 3.78	$ 3.51	$ 0.27	8%

Revenues

Coal royalties revenues increased due to the increase in the average coal royalty received per ton and a slight increase in tons produced. The coal markets improved in 2010 and remain fairly strong as the metallurgical coal markets continue to lead the way.

Coal production by our lessees increased slightly due to higher production in the San Juan Basin resulting from the startup of a second mine in 2009 and the addition of new equipment in 2010. Longwall mining activity increased production in the Northern Appalachia region. These increases were partially offset by a decline in production in the Illinois Basin region, which was due to poor mining conditions at certain mines. Central Appalachia production remained relatively consistent with increased production in West Virginia as certain mines increased production was offset by decreased production in Virginia due to normal depletion and timing of when operators were mining on or off our properties.

Coal services revenues have increased due to the operating results of our joint venture providing fee-based coal-related infrastructure facilities to certain lessees.

Timber revenues increased due to higher sales prices received for harvested timber, partially offset by a lower harvest in 2010 resulting from weakened market conditions for furniture-grade wood and construction products. The average price received for timber increased 30% from $209 per Mbf in 2009 to $271 per Mbf in 2010.

The oil and gas royalty revenue increase was primarily attributable to higher natural gas prices in 2010. Realized prices received for natural gas increased 11% from $4.55 per Mcf in 2009 to $5.07 per Mcf in 2010.

Other revenues, which consisted primarily of wheelage fees, forfeiture income and management fees, decreased due to lower forfeiture income in 2010.

Expenses

Operating expenses increased due to increased coal royalties and timber related costs. Increased mining activity by our lessees from subleased properties in the Central Appalachia region increased coal royalties expense. Mining activity on our subleased property fluctuates between periods due to the proximity of our property boundaries and other mineral owners. Weather and its effects on timber harvesting activities increased timber costs in 2010.

General and administrative expenses increased as a result of our change in management structure. Some shared costs with Penn Virginia have been replaced with direct costs and the change in ownership accelerated the vesting of equity compensation. Penn Virginia divested its interest in PVG during 2009 and 2010 and no longer owns any limited or general partner interest in PVR. Because the divestiture was considered a change of control under the long-term incentive plan, all unvested restricted and phantom units granted to employees performing services for the benefit of PVR were considered vested on the date the last PVG units were sold, June 7, 2010. Approximately $2.1 million was expensed related to the accelerated vesting for the Coal and Natural Resource Management segment. In addition to the change in management structure, costs related to acquisitions and due diligence have increased.

The $1.5 million impairment expense in 2009 was the result of a reduction in the value of an intangible asset. We test long-lived assets for impairment if a triggering event occurs and the impairment was triggered by a wheelage contract being rejected in bankruptcy. As a result of the impairment, the fair value of the contract was reduced to zero.

DD&A expenses decreased slightly due to decreased timber depletion expense resulting from the lower harvest in 2010. The decrease is partially offset by an increase in coal depletion due to a shift in production mix of coal mined from our properties by our lessees. On a per ton basis, DD&A decreased from $0.91 per ton in 2009 to $0.89 per ton in 2010.

Year Ended December 31, 2009 Compared With Year Ended December 31, 2008

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 periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Financial Highlights				
Revenues				
Coal royalties	$ 120,435	$ 122,834	(2,399)	(2%)
Coal services	7,332	7,355	(23)	(0%)
Timber	5,726	6,943	(1,217)	(18%)
Oil and gas royalty	2,471	5,989	(3,518)	(59%)
Other	8,636	10,206	(1,570)	(15%)
Total revenues	144,600	153,327	(8,727)	(6%)
Expenses				
Operating	9,692	12,940	3,248	25%
General and administrative	14,539	13,286	(1,253)	(9%)
Impairments	1,511	—	(1,511)	—
Depreciation, depletion and amortization	31,330	30,805	(525)	(2%)
Total expenses	57,072	57,031	(41)	(0%)
Operating income	87,528	96,296	(8,768)	(9%)
Other data				
Coal royalty tons by region				
Central Appalachia	18,319	19,587	(1,268)	(6%)
Northern Appalachia	3,786	3,578	208	6%
Illinois Basin	4,724	4,584	140	3%
San Juan Basin	7,501	5,941	1,560	26%
Total tons	34,330	33,690	640	2%
Coal royalties revenues by region				
Central Appalachia	85,183	93,577	(8,394)	(9%)
Northern Appalachia	6,931	6,568	363	6%
Illinois Basin	12,420	10,451	1,969	19%
San Juan Basin	15,901	12,238	3,663	30%
Total royalties	120,435	122,834	(2,399)	(2%)
Coal royalties per ton by region ($/ton)				
Central Appalachia	$ 4.65	$ 4.78	$ (0.13)	(3%)
Northern Appalachia	1.83	1.84	(0.01)	(1%)
Illinois Basin	2.63	2.28	0.35	15%
San Juan Basin	2.12	2.06	0.06	3%
Average royalties per ton	$ 3.51	$ 3.65	$ (0.14)	(4%)

Revenues

Coal royalties revenues decreased slightly due to the decrease in the average coal royalty received per ton. This decrease was due to an overall shift in production mix to lower royalty lessees, primarily to fixed rate leases in the San Juan Basin from the higher royalty Central Appalachian region.

Coal production by our lessees increased slightly due to higher production in the San Juan Basin resulting from the startup of a second mine and improved mining conditions. This increase was partially offset by a decline in production in the Central Appalachian region which was due to a reduction in longwall mining activity and a depressed coal market.

Timber revenues decreased due to lower sales prices resulting from weakened market conditions for furniture-grade wood products. The average price received for timber decreased 27% from $287 per Mbf in 2008 to $209 per Mbf in 2009.

The oil and gas royalty revenues decrease was primarily attributable to lower natural gas prices in 2009. Realized prices received for natural gas decreased 57% from $10.63 per Mcf in 2008 to $4.55 per Mcf in 2009.

Other revenues, which consisted primarily of wheelage fees, forfeiture income and management fees, decreased due to lower wheelage income from a decline in coal production in certain areas. In addition, in 2008, a $0.8 million gain on the settlement of unmined coal was recognized.

Expenses

Coal royalties expenses decreased due to a decline in mining activity by our lessees from subleased properties in the Central Appalachian region where our coal royalties expense is primarily incurred. Mining activity on our subleased property fluctuates between periods due to the proximity of our property boundaries and other mineral owners.

General and administrative expenses increased as a result of an uncollectible account receivable resulting from a lessee bankruptcy and increased staffing and related benefit costs.

The $1.5 million impairment expense in 2009 was the result of a reduction in the value of an intangible asset. We test long-lived assets for impairment if a triggering event occurs and the impairment was triggered by a wheelage contract being rejected in bankruptcy. As a result of the impairment, the fair value of the contract was reduced to zero.

DD&A expenses increased slightly due to higher depletion expense resulting from the increase in coal mined from our properties by our lessees. On a per ton basis, DD&A remained constant at $0.91 per ton for both periods.

Natural Gas Midstream Segment

Year Ended December 31, 2010 Compared With Year Ended December 31, 2009

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 periods presented:

	Year Ended December 31,		Favorable	
	2010	**2009**	**(Unfavorable)**	**% Change**
Financial Highlights				
Revenues				
Residue gas (1)	$ 359,745	$ 289,427	$ 70,318	24%
Natural gas liquids	297,885	182,794	115,091	63%
Condensate	26,425	17,010	9,415	55%
Gathering, processing and transportation fees	18,109	15,558	2,551	16%
Total natural gas midstream revenues	702,164	504,789	197,375	39%
Equity earnings in equity investment	6,664	5,548	1,116	20%
Producer services	2,820	1,767	1,053	60%
Total revenues	711,648	512,104	199,544	39%
Expenses				
Cost of gas purchased (1)	577,813	406,583	(171,230)	(42%)
Operating	32,806	29,096	(3,710)	(13%)
General and administrative	23,235	16,746	(6,489)	(39%)
Depreciation and amortization	45,027	38,905	(6,122)	(16%)
Total operating expenses	678,881	491,330	(187,551)	(38%)
Operating income	$ 32,767	$ 20,774	$ 11,993	58%
Operating Statistics				
System throughput volumes (MMcf)	129,703	121,335	8,368	7%
Daily throughput volumes (MMcfd)	355	332	23	7%
Gross margin	$ 124,351	$ 98,206	$ 26,145	27%
Cash impact of derivatives	(1,860)	10,566	(12,426)	(118%)
Gross margin, adjusted for impact of derivatives	$ 122,491	$ 108,772	$ 13,719	13%
Gross margin ($/Mcf)	$ 0.96	$ 0.81	$ 0.15	19%
Cash impact of derivatives ($/Mcf)	(0.02)	0.09	(0.11)	(122%)
Gross margin, adjusted for impact of derivatives ($/Mcf)	$ 0.94	$ 0.90	$ 0.04	4%

(1) For the period of January 1 through June 7, 2010 and for the year ended December 31, 2009, we recorded $27.8 million and $72.5 million of natural gas midstream revenue and $27.8 million and $72.5 million for the cost of midstream gas purchased related to the purchase of natural gas from PVOG LP, a subsidiary of Penn Virginia Corporation and considered a related party up to June 7, 2010, and the subsequent sale of that gas to third parties. We took title to the gas prior to transporting it to third parties. These transactions do not impact the gross margin.

Gross Margin

Gross 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.

The gross margin increase was a result of higher commodity pricing and higher fractionation, or frac spreads. System volumes also increased during 2010, but primarily on systems not entirely exposed to commodity pricing. These systems include a newly constructed system in the Marcellus region of Northeastern Pennsylvania (a fee-based gathering system) and Crossroads (a primarily fee-based gathering and processing system, which does have some exposure to percentage of proceeds contracts). The volumes at our Panhandle and Crossroads processing plants (inlet volumes) also increased during 2010. Processing contracts on our Panhandle system are primarily gas purchase and percentage of proceeds contracts. Thus, we experienced a growth in our gross margin due higher commodity pricing and frac spreads.

Drilling activity during 2010 increased in areas which produce rich gas (natural gas containing significant NGLs). As a result, the number of wells drilled and connected to our Panhandle System increased. Our expansion and acquisition activities throughout 2010 and 2009, especially in the Panhandle System, have alleviated pipeline pressure problems and allowed us to move more gas in this region to our processing plants. We have also increased our capital spending in growth areas, such as the Marcellus region. Our new Marcellus Systems are primarily fee-based systems in a very active drilling area.

During 2010, we generated a majority of the gross margin from contractual arrangements under which the gross 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 discussion of the types of contracts utilized by the 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. See Note 6 to the Consolidated Financial Statements for a description of our derivatives program. On a per Mcf basis, adjusted for the impact of our commodity derivative instruments, our gross margin increased in 2010 by $0.04, or 4%. The unfavorable impact of commodity derivatives is a result of changing commodity prices during 2010 and the expiration of older derivative instruments.

Revenues Other Than Gross Margin

Equity earnings in our equity investments increased as we continue to see increased volumes on the systems managed by these joint ventures. The increase at Crosspoint is directly related to the increased volumes at the Crossroads plant. Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin, also saw increased earnings due to mainline volume increases in the Powder River Basin.

Producer services revenues increased due to increased natural gas pricing and volumes moved by producers.

Expenses

Operating expenses increased due to our expanding footprint on existing and newly constructed systems. Increased costs include compressor rentals and labor costs.

General and administrative expenses increased as a result of our change in management structure. Some shared costs with Penn Virginia have been replaced with direct costs and the change in ownership accelerated the vesting of equity compensation. Penn Virginia divested its interest in PVG during 2009 and 2010 and no longer owns any limited or general partner interest in PVR. Because the divestiture was considered a change of control under the long-term incentive plan, all unvested restricted and phantom units granted to employees performing services for the benefit of PVR were considered vested on the date the last PVG units were sold, June 7, 2010. Approximately $3.5 million was expensed related to the accelerated vesting for the Natural Gas Midstream segment.

Depreciation and amortization expenses increased primarily due to capital expansions on the Panhandle and Marcellus Systems.

Year Ended December 31, 2009 Compared With Year Ended December 31, 2008

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 periods presented:

	Year Ended December 31, 2009	2008	Favorable (Unfavorable)	% Change
Financial Highlights				
Revenues				
Residue gas (1)	$ 289,427	$ 452,535	$ (163,108)	(36%)
Natural gas liquids	182,794	229,765	(46,971)	(20%)
Condensate	17,010	26,009	(8,999)	(35%)
Gathering, processing and transportation fees	15,558	11,693	3,865	33%
Total natural gas midstream revenues	504,789	720,002	(215,213)	(30%)
Equity earnings in equity investment	5,548	2,408	3,140	130%
Producer services	1,767	5,843	(4,076)	(70%)
Total revenues	512,104	728,253	(216,149)	(30%)
Expenses				
Cost of gas purchased (1)	406,583	612,530	205,947	34%
Operating	29,096	23,009	(6,087)	(26%)
General and administrative	16,746	14,606	(2,140)	(15%)
Impairments	-	31,801	31,801	100%
Depreciation and amortization	38,905	27,361	(11,544)	(42%)
Total operating expenses	491,330	709,307	217,977	31%
Operating income	$ 20,774	$ 18,946	$ 1,828	10%
Operating Statistics				
System throughput volumes (MMcf)	121,335	98,683	22,652	23%
Daily throughput volumes (MMcfd)	332	270	62	23%
Gross margin	$ 98,206	$ 107,472	$ (9,266)	(9%)
Cash impact of derivatives	10,566	(31,709)	42,275	133%
Gross margin, adjusted for impact of derivatives	$ 108,772	$ 75,763	$ 33,009	44%
Gross margin ($/Mcf)	$ 0.81	$ 1.09	$ (0.28)	(26%)
Cash impact of derivatives ($/Mcf)	0.09	(0.32)	0.41	128%
Gross margin, adjusted for impact of derivatives ($/Mcf)	$ 0.90	$ 0.77	$ 0.13	17%

(1) In 2009 and 2008, we recorded $72.5 million and $127.9 million of natural gas midstream revenue and $72.5 million and $127.9 million for the cost of midstream gas purchased related to the purchase of natural gas from PVOG LP and the subsequent sale of that gas to third parties. We take title to the gas prior to transporting it to third parties. These transactions do not impact the gross margin.

Gross Margin

The gross margin decrease was a result of lower commodity pricing and lower frac spreads, partially offset by increased system throughput volumes and increased natural gas processing capacity.

Drilling activities by producers central to our natural gas gathering and processing plants were at reduced levels from the previous year due to lower natural gas prices. However, the 2009 system throughput volumes benefited from the results of drilling activity in 2008 and the first part of 2009. The expansion and acquisition activity, especially in the Panhandle System, has alleviated pipeline pressures and allowed us to move all of our gas in this region to our processing plants. As noted above, in July 2009 we completed an acquisition of gas processing and residue pipeline facilities in western Oklahoma. The acquired assets included the 60 MMcfd Sweetwater plant. Additionally, we completed a 40 MMcfd processing plant expansion in our Spearman complex that was put into service on July 31, 2009. The acquired and expanded processing facilities increased our processing capacity in the Panhandle System to 260 MMcfd and overall processing capacity to 400 MMcfd. The increased processing capacity has allowed us to process natural gas volumes that were being bypassed due to processing capacity constraints in the Panhandle System and has alleviated pipeline pressurerelated volume constraints in the eastern portion of the Panhandle.

During 2009, we generated a majority of the gross margin from contractual arrangements under which the gross 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 discussion of the types of contracts utilized by the 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. See Note 6 to the Consolidated Financial Statements for a description of our derivatives program. On a per Mcf basis, adjusted for the impact of our commodity derivative instruments, our gross margin increased in 2009 by $0.13, or 17%. This favorable impact of commodity derivatives is a result of overall lower commodity prices during 2009 and the expiration of older derivative instruments.

Revenues Other Than Gross Margin

Equity earnings in equity investment increased due to a full year of results in 2009 compared with a partial year in 2008. In April 2008, we acquired a 25% member interest in Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. In addition, revenues from the joint venture have grown in 2009 due to mainline volume increases in the Powder River Basin.

Producer services revenues decreased due to a negative relative change in the natural gas indices on which our purchases and sales of natural gas are based and a decrease in marketing fees resulting from lower commodity prices.

Expenses

Operating expenses increased due to prior and current years' acquisitions, expansion projects, compressor rentals and labor costs. Increased costs for property taxes, compressor rentals and labor costs were incurred due to expanding our footprint in the Panhandle System.

General and administrative expenses increased due to increased staffing and related benefit costs. The increase was primarily attributable to labor costs resulting from the 2008 acquisitions and plant expansions. We incurred a full year of salaries and benefits in 2009 compared with a partial year in 2008.

Impairment expense in 2008 was the result of a reduction in the value of goodwill. We test goodwill for impairment on an annual basis, at a minimum, and more frequently if a triggering event occurs. The goodwill testing during the fourth quarter of 2008 identified a goodwill impairment loss of $31.8 million. The impairment charge, which was triggered by fourth quarter declines in oil and gas spot and futures prices and a decline in our market capitalization, reduced to zero all goodwill recorded in conjunction with acquisitions made by our natural gas midstream segment in 2008 and prior years.

Depreciation and amortization expenses increased primarily due to acquisitions, capital expansions on the Spearman and Sweetwater plants and new well connections in existing areas of operation.

Other

Our other results consist of interest expense and derivative gains and losses. The following table sets forth a summary of certain financial data for our other results for the periods presented:

	Year Ended December 31,		
	2010	**2009**	**2008**
Operating income	$ 125,899	$ 108,302	$ 115,242
Other income (expense)			
Interest expense	(35,591)	(24,653)	(24,672)
Other	643	1,280	(2,907)
Derivatives	(22,493)	(19,714)	16,837
Net income	$ 68,458	$ 65,215	$ 104,500

Interest Expense. Our consolidated interest expense increased during 2010 due to the issuance of Senior Notes. The Senior Notes bear an 8.25% interest rate, whereas the Revolver's annualized interest rates have been 2.5%, 2.7% and 4.2% for the years ended December 31, 2010, 2009 and 2008. The Senior Notes were issued to pay down borrowing on the Revolver and to increase the availability of funds under the Revolver for acquisitions and growth capital needs. Non-cash interest expense has also increased over the three year period due to the issuance of the Senior Notes and amendment fees on the Revolver.

Derivatives. Our results of operations and operating cash flows were impacted by changes in market prices for NGLs, crude oil and natural gas prices, as well as the Interest Rate Swaps.

Commodity markets are volatile, and as a result, our hedging activity results can vary significantly. Our results of operations are affected by the volatility of changes in fair value, which fluctuate with changes in NGL, crude oil and natural gas prices. We determine the fair values of our commodity derivative agreements based on discounted cash flows based on quoted forward prices for the respective commodities. The discounted cash flows utilize discount rates adjusted for the credit risk of our counterparties for derivatives in an asset position, and our own credit risk for derivatives in a liability position.

During the first quarter of 2009, we discontinued hedge accounting for all of the Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Interest Rate Swaps are recognized in the derivatives line item on our Consolidated Statements of Income.

Our derivative activity for the periods presented is summarized below:

	Year Ended December 31,		
	2010	2009	2008
Interest Rate Swap unrealized derivative gain	$ 1,000	$ 3,260	-
Interest Rate Swap realized derivative loss	(8,215)	(7,566)	-
Interest Rate Swap other comprehensive income reclass	(715)	-	-
Natural gas midstream commodity unrealized derivative gain (loss)	(12,703)	(25,974)	55,303
Natural gas midstream commodity realized derivative gain (loss)	(1,860)	10,566	(38,466)
Total derivative gain (loss)	$ (22,493)	$ (19,714)	$ 16,837

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 on the relevant lessees for all environmental and reclamation liabilities arising under those laws and regulations. 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, 2010 and 2009, our environmental liabilities were $0.9 million and $1.0 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."

Critical Accounting 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.

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 after the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. We record any differences, which historically have not been significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Natural Gas Midstream Gross Margin

Our gross 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. 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. Cost of midstream gas purchased consists of amounts payable to third-party producers for natural gas purchased under percentage-of-proceeds and gas purchase/keep-whole contracts.

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 and the calculation of the cost of midstream gas purchased 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 historically have not been significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Depreciation, Depletion and Amortization

We compute depreciation and amortization of property, plant and equipment using the straight-line balance method over the estimated useful life of each asset.

Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by our own geologists and outside consultants. Our estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. 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 using a methodology consistent with the units-of-production method, but that is based on the quantity of timber harvested. 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. When we retire or sell an asset, we remove its cost and related accumulated depreciation and amortization from our Consolidated Balance Sheets. Upon sale, we record the difference between the net book value, net of any assumed asset retirement obligation, and proceeds from disposition as a gain or loss.

Intangible assets are primarily associated with assumed contracts, customer relationships and rights-of-way. These intangible assets are amortized over periods of up to 20 years, the period in which benefits are derived from the contracts, customer relationships and rights-of-way, and are combined with property, plant and equipment and are reviewed for impairment. See Note 10 to the Consolidated Financial Statements for a more detailed description of our intangible assets.

Derivative Activities

From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas, crude oil and NGL price volatility. The derivative financial instruments, which are placed with financial institutions that we believe are of acceptable credit risks, take the form of collars and swaps. All derivative financial instruments are recognized in our Consolidated Financial Statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. 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.

During the first quarter of 2009, we discontinued hedge accounting for all of the Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Interest Rate Swaps are recognized in the derivatives line item on our Consolidated Statements of Income. At December 31, 2010, a $0.4 million gain remained in accumulated other comprehensive income related to the Interest Rate Swaps. The $0.4 million gain will be recognized in the derivatives line item as the Interest Rate Swaps settle.

We recognize changes in fair value in earnings currently in the derivatives line on the Consolidated Statements of Income. We have experienced and could continue to experience significant changes in the estimate of unrealized derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts. The discontinuation of hedge accounting has no impact on our reported cash flows, although our results of operations are affected by the volatility of mark-to-market gains and losses and changes in fair value, which fluctuate with changes in natural gas, crude oil, NGL prices and interest rates. These fluctuations could be significant in a volatile pricing environment. See Note 6 to the Consolidated Financial Statements for a further description of our derivatives program.

Impairment of Goodwill

Goodwill has been allocated to our natural gas midstream segment and recorded in connection with acquisitions and business combinations. This goodwill is not amortized, but tested for impairment at least annually. Goodwill impairment is determined using a two-step test. The first step of the impairment test is used to identify potential impairment by comparing the fair value of a reporting unit to the book value, including goodwill. If the fair value of a reporting unit exceeds its book value, goodwill of the reporting unit is not considered impaired, and the second step of the impairment test is not required. If the book value of a reporting unit exceeds its fair value, the second step of the impairment test is performed to measure the amount of impairment loss, if any. The second step of the impairment test compares the implied fair value of the reporting unit's goodwill with the book value of that goodwill. If the book value of the reporting unit's goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination.

We tested goodwill for impairment during the fourth quarter of 2008 and recorded a goodwill impairment loss of $31.8 million. The impairment loss, which was triggered by fourth quarter declines in oil and gas spot and futures prices and a decline in our market capitalization, reduced to zero all goodwill recorded in conjunction with acquisitions made by the natural gas midstream segment in 2008 and prior years. This loss was recorded in the impairment line on our Consolidated Statements of Income. Our goodwill balance remained at zero at December 31, 2010. See Note 9 to the Consolidated Financial Statements for a description of goodwill and the related impairment loss.

Equity Investments

We use the equity method of accounting to account for our 25% member interest in Thunder Creek, as well as our investment in a 50% member interest in a coal handling joint venture and 50% member interest in Crosspoint, recording the initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect our share of income of the investee and capital contributions, and is reduced to reflect our share of losses of the investee or distributions received from the investee as the joint ventures report them. Our share of earnings or losses from Thunder Creek and Crosspoint is included in other revenues on the Consolidated Statements of Income, and our share of earnings and losses from the coal handling joint venture is included in coal services on the Consolidated Statements of Income. Other revenues and coal services revenues also include amortization of the amount of the equity investments that exceed our portion of the underlying equity in net assets (the inside/outside basis). We record this amortization over the life of the contracts acquired in the Thunder Creek acquisition and the life of the coal services contracts acquired in the acquisition of the coal handling joint venture.

New Accounting Standards

See Note 2 to the Consolidated Financial Statements for a description of recent accounting standards.

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 as follows:

- Price Risk
- Interest Rate Risk
- Customer Credit Risk

As a result of our risk management activities as discussed below, we are also exposed to counterparty risk with financial institutions with whom we enter into these risk management positions. Sensitivity to these risks has heightened due to the state of the global economy, including financial and credit markets.

We have completed a number of acquisitions in recent years. See Note 3 to the Consolidated Financial Statements for a description of our material acquisitions. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, and the resulting amount of goodwill, if any. Changes in operations, further decreases in commodity prices, changes in the business environment or market conditions could substantially alter management's assumptions and could result in lower estimates of values of acquired assets or of future cash flows. If these events occur, it is reasonably possible that we could record a significant impairment loss on our Consolidated Statements of Income.

Price Risk

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 acceptable 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.

At December 31, 2010, we reported a net commodity derivative liability related to the natural gas midstream segment of $15.9 million that is with five counterparties and is substantially concentrated with three of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. No significant uncertainties related to the collectability of amounts owed to us exist with regard to these counterparties.

In 2010, we reported a net derivative loss of $22.5 million. Some of our commodity derivative financial instruments initially qualified as cash flow hedges, and changes in the effective portion of fair value from these contracts were deferred in accumulated comprehensive income until the hedged transactions settled. When we discontinued hedge accounting for commodity derivatives in 2006, a net loss remained in accumulated other comprehensive income. As the hedged transactions settled in 2007 and 2008, we recognized these deferred changes in fair value in revenues and cost of gas purchased in our Consolidated Statements of Income. As of December 31, 2008, no net losses remained in accumulated other comprehensive income related to our natural gas midstream commodity derivatives.

Because we no longer use hedge accounting for our commodity derivatives, we recognize changes in fair value in earnings currently in the derivatives line on the Consolidated Statements of Income. We have experienced and could continue to experience significant changes in the estimate of unrealized derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts. The discontinuation of hedge accounting has no impact on our reported cash flows, although our results of operations are affected by the volatility of mark-to-market gains and losses and changes in fair value, which fluctuate with changes in natural gas crude oil and NGL prices. These fluctuations could be significant in a volatile pricing environment.

The following table lists our commodity derivative agreements and their fair values as of December 31, 2010:

	Average Volume Per Day	Swap Price	Weighted Average Price Put	Weighted Average Price Call	Fair Value at December 31, 2010
					(in thousands)
NGL - natural gasoline collar	**(gallons)**		**(per gallon)**		
First quarter 2011 through fourth quarter 2011	95,000		$1.57	$1.94	$ (7,924)
Crude oil collar	**(barrels)**		**(per barrel)**		
First quarter 2011 through fourth quarter 2011	400		$75.00	$98.50	(475)
Natural gas purchase swap	**(MMBtu)**	**(MMBtu)**			
First quarter 2011 through fourth quarter 2011	6,500	$5.80			(2,909)
NGL – natural gasoline collar	**(gallons)**		**(per gallon)**		
First quarter 2012 through fourth quarter 2012	54,000		$1.75	$2.02	(2,802)
Crude oil swap	**(barrels)**	**(per barrel)**			
First quarter 2012 through fourth quarter 2012	600	$88.62			(1,106)
Natural gas purchase swap	**(MMBtu)**	**(MMBtu)**			
First quarter 2012 through fourth quarter 2012	4,000	$5.195			(162)
Settlements to be paid in subsequent period					(561)
					$ (15,939)

We estimate that a $5.00 per barrel increase in the crude oil price would decrease the fair value of our crude oil collars by $1.5 million. We estimate that a $5.00 per barrel decrease in the crude oil price would increase the fair value of our crude oil collars by $1.4 million. We estimate that a $1.00 per MMBtu increase in the natural gas price would increase the fair value of our natural gas purchase swaps by $3.6 million. We estimate that a $1.00 per MMBtu decrease in the natural gas price would decrease the fair value of our natural gas purchase swaps by $3.6 million. We estimate that a $0.11 per gallon increase in the natural gasoline (a natural gas liquid, NGL) price would decrease the fair value of our natural gasoline collar by $4.6 million. We estimate that a $0.11 per gallon decrease in the natural gasoline price would increase the fair value of our natural gasoline collar by $4.4 million.

We estimate that, excluding the effects of derivative positions described above, for every $1.00 per MMBtu increase or decrease in the natural gas price, our natural gas midstream gross margin and operating income in 2010 would increase or decrease by $0.9 million. In addition, we estimate that for every $5.00 per barrel increase or decrease in the crude oil price, our natural gas midstream gross margin and operating income in 2010 would increase or decrease by $5.9 million. This assumes that natural gas prices, crude oil prices and inlet volumes remain constant at anticipated levels. These estimated changes in our gross margin and operating income exclude potential cash receipts or payments in settling these derivative positions.

Interest Rate Risk

As of December 31, 2010, we had $408.0 million of outstanding indebtedness under the Revolver, which carries a variable interest rate throughout its term. We entered into the Interest Rate Swaps to establish fixed interest rates on a portion of the outstanding indebtedness under the Revolver. From March 2010 to December 2011, the notional amounts of the Interest Rate Swaps total $250.0 million, or 61% of our outstanding indebtedness under the Revolver as of December 31, 2010, with us paying a weighted average fixed rate of 3.37% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. From December 2011 to December 2012, the notional amounts of the Interest Rate Swaps total $100.0 million, or 25% of our outstanding indebtedness under the Revolver as of December 31, 2010,with us paying a weighted average fixed rate of 2.09% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. A 1% increase in short-term interest rates on the floating rate debt outstanding under the Revolver (net of amounts fixed through the Interest Rate Swaps) as of December 31, 2010 would cost us approximately $2.5 million in additional interest expense per year.

During the first quarter of 2009, we discontinued hedge accounting for all of the Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Interest Rate Swaps are recognized in earnings currently. Therefore, our results of operations are affected by the volatility of changes in fair value, which fluctuates with changes in interest rates. These fluctuations could be significant. See Note 6 to the Consolidated Financial Statements for a further description of our derivatives program.

Customer Credit Risk

We are exposed to the credit risk of our customers and lessees. Approximately 87%, or $84.7 million, of our consolidated accounts receivable at December 31, 2010 resulted from our natural gas midstream segment and approximately 13%, or $13.1 million, resulted from our coal and natural resource management segment. Approximately $38.0 million of the natural gas midstream segment's receivables at December 31, 2010 related to four customers, Conoco Phillips Company, Tenaska Marketing Ventures, Targa Liquids Marketing and Trade and Williams NGL Marketing, LLC. At December 31, 2010, 46% of our natural gas midstream segment accounts receivable and 38% of our consolidated accounts receivable related to these natural gas midstream customers. No significant uncertainties related to the collectability of amounts owed to us exist in regard to this natural gas midstream customer.

This customer concentration increases our exposure to credit risk on our receivables, since the financial insolvency of these customers could have a significant impact on our results of operations. If our customers or lessees become financially insolvent, they may not be able to continue to operate or meet their payment obligations. Any material losses as a result of customer defaults could harm and have an adverse effect on our business, financial condition or results of operations. Substantially all of our trade accounts receivable are unsecured.

To mitigate the risks of nonperformance by our customers, we perform ongoing credit evaluations of our existing customers. We monitor individual customer payment capability in granting credit arrangements to new customers by performing credit evaluations, seek to limit credit to amounts we believe the customers can pay, and maintain reserves we believe are adequate to cover exposure for uncollectable accounts. As of December 31, 2010, no receivables were collateralized, and we had recorded a $0.2 million allowance for doubtful accounts in the natural gas midstream segment.

Future Accounting Pronouncements

A consensus was reached regarding business combinations and the related disclosure of supplementary pro forma information. The consensus specifies that if a public entity presents comparative financial statements, the entity (acquirer) should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. It also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. This accounting standard is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010.

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., and subsidiaries as of December 31, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, 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, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 24, 2011, expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 24, 2011

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, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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. and subsidiaries as of December 31, 2010 and 2009, 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, 2010, and our report dated February 24, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 24, 2011

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per unit amounts)

	Year Ended December 31,		
	2010	**2009**	**2008**
Revenues			
Natural gas midstream	$ 702,164	$ 504,789	$ 720,002
Coal royalties	130,349	120,435	122,834
Coal services	7,830	7,332	7,355
Other	23,793	24,148	31,389
Total revenues	864,136	656,704	881,580
Expenses			
Cost of gas purchased	577,813	406,583	612,530
Operating	44,243	38,788	35,949
General and administrative	40,281	31,285	27,892
Impairments	-	1,511	31,801
Depreciation, depletion and amortization	75,900	70,235	58,166
Total expenses	738,237	548,402	766,338
Operating income	125,899	108,302	115,242
Other income (expense)			
Interest expense	(35,591)	(24,653)	(24,672)
Other	643	1,280	(2,907)
Derivatives	(22,493)	(19,714)	16,837
Net income	$ 68,458	$ 65,215	$ 104,500
General partner's interest in net income	$ 25,209	$ 24,962	$ 23,715
Limited partners' interest in net income	$ 43,249	$ 40,253	$ 80,785
Basic and diluted net income per limited partner unit (see Note 14)	$ 0.83	$ 0.76	$ 1.63
Weighted average number of units outstanding, basic and diluted	52,094	51,799	49,495

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit amounts)

	December 31, 2010	December 31, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 10,651	$ 8,659
Accounts receivable, net of allowance for doubtful accounts	97,787	82,321
Derivative assets	-	1,331
Other current assets	5,900	4,468
Total current assets	114,338	96,779
Property, plant and equipment	1,295,227	1,162,070
Accumulated depreciation, depletion and amortization	(324,181)	(261,226)
Net property, plant and equipment	971,046	900,844
Equity investments	84,327	87,601
Intangible assets, net	76,950	83,741
Derivative assets	-	1,284
Other long-term assets	50,840	37,811
Total assets	$ 1,297,501	$ 1,208,060
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable and accrued liabilities	$ 104,636	$ 70,405
Deferred income	4,360	3,839
Derivative liabilities	19,516	11,251
Total current liabilities	128,512	85,495
Deferred income	7,874	5,482
Other liabilities	19,494	16,191
Derivative liabilities	5,107	4,285
Senior notes	300,000	-
Revolving credit facility	408,000	620,100
Commitments and contingencies (see Note 16)		
Partners' capital		
Common units (52,293,381 at December 31, 2010 and 51,798,895 at December 31, 2009)	422,203	471,068
General partner interest	5,902	6,834
Accumulated other comprehensive income	409	(1,395)
Total partners' capital	428,514	476,507
Total liabilities and partners' capital	$ 1,297,501	$ 1,208,060

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, 2010	2009	2008
Cash flows from operating activities			
Net income	$ 68,458	$ 65,215	$ 104,500
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	75,900	70,235	58,166
Impairments	-	1,511	31,801
Commodity derivative contracts:			
Total derivative losses (gains)	23,583	22,700	(11,357)
Cash receipts (payments) to settle derivatives	(10,075)	3,000	(38,466)
Non-cash interest expense	5,278	4,391	2,693
Non-cash unit-based compensation	6,157	1,769	-
Equity earnings, net of distributions received	3,274	(2,537)	(224)
Other	(876)	(1,004)	(1,408)
Changes in operating assets and liabilities:			
Accounts receivable	(15,462)	(8,387)	5,607
Accounts payable and accrued liabilities	22,219	4,561	(8,228)
Deferred income	2,913	(1,671)	1,145
Other asset and liabilities	2,327	189	(5,053)
Net cash provided by operating activities	183,696	159,972	139,176
Cash flows from investing activities			
Acquisitions	(24,876)	(29,580)	(260,376)
Additions to property, plant and equipment	(99,240)	(51,097)	(71,652)
Other	1,329	1,147	998
Net cash used in investing activities	(122,787)	(79,530)	(331,030)
Cash flows from financing activities			
Distributions to partners	(124,595)	(124,009)	(111,076)
Proceeds from issuance of senior notes	300,000	-	-
Proceeds from borrowings	158,000	132,000	453,800
Repayments of borrowings	(370,100)	(80,000)	(297,800)
Net proceeds from issuance of partners' capital	183	-	141,084
Debt issuance costs and other	(22,405)	(9,258)	(4,200)
Net cash provided by (used in) financing activities	(58,917)	(81,267)	181,808
Net increase (decrease) in cash and cash equivalents	1,992	(825)	(10,046)
Cash and cash equivalents – beginning of period	8,659	9,484	19,530
Cash and cash equivalents – end of period	$ 10,651	$ 8,659	$ 9,484
Supplemental disclosure:			
Cash paid for interest	$ 31,833	$ 25,271	$ 23,282
Noncash investing activities:			
Issuance of PVR units for acquisition	$ -	$ -	$ 15,171
PVG units given as consideration for acquisition	$ -	$ -	$ 68,021
Other liabilities related to acquisitions	$ 2,765	$ -	$ 4,673

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		General Partner	Accumulated Other Comprehensive Income (Loss)	Total	Comprehensive Income (Loss)
	Units	Amount				
Balance at December 31, 2007	46,106	$ 373,915	$ 4,753	$ (7,392)	$ 371,276	
Public unit offering (See Note 4)	5,150	138,141	2,943	-	141,084	
Issuance of units for acquisition (See Note 3)	543	21,316	435	-	21,751	
Distributions ($1.82 per unit)	-	(89,207)	(21,869)	-	(111,076)	
Net income allocation	-	82,762	21,738	-	104,500	$ 104,500
Other comprehensive income	-	-	-	3,147	3,147	3,147
Balance at December 31, 2008	51,799	$ 526,927	$ 8,000	$ (4,245)	$ 530,682	$ 107,647
Unit based compensation	-	1,769	-	-	1,769	
Distributions ($1.88 per unit)	-	(97,881)	(26,128)	-	(124,009)	
Net income allocation	-	40,253	24,962	-	65,215	$ 65,215
Other comprehensive income	-	-	-	2,850	2,850	2,850
Balance at December 31, 2009	51,799	$ 471,068	$ 6,834	$ (1,395)	$ 476,507	$ 68,065
Unit based compensation	494	6,157	-	-	6,157	
Capital contributions	-		183	-	183	
Distributions ($1.88 per unit)	-	(98,329)	(26,266)	-	(124,595)	
Net income allocation	-	43,307	25,151	-	68,458	$ 68,458
Other comprehensive income	-	-	-	1,804	1,804	1,804
Balance at December 31, 2010	52,293	$ 422,203	$ 5,902	$ 409	$ 428,514	$ 70,262

See accompanying 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 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: (i) coal and natural resource management and (ii) natural gas midstream.

Our coal and natural resource management segment primarily involves the management and leasing of coal properties and the subsequent collection of royalties. Our coal reserves are primarily located in Kentucky, Virginia, West Virginia, Illinois and New Mexico. We also earn revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage, fees. We also own a member interest in a joint venture providing end-user coal handling facilties.

Our natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. We own and operate natural gas midstream assets located in Oklahoma, Pennsylvania and 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. In addition, we own member interests in two midstream joints ventures that gather and transport natural gas. 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 ("PVR GP"), which is a wholly owned subsidiary of Penn Virginia GP Holdings, L.P. ("PVG"), a publicly traded Delaware limited partnership. Effective June 7, 2010, Penn Virginia Corporation ("PVA") completed its divestiture of PVG and as a result, PVA no longer owns any limited or general partnership interests in us or PVG. At December 31, 2010, PVG owned an approximately 37% limited partner interest in us as well as 100% of our general partner, which owns a 2% general partner interest in us.

In connection with PVA's reduction of its limited partner interest in PVG, we implemented certain changes in management, as a result of which certain executive officers of Penn Virginia resigned as executive officers and directors of Penn Virginia Resource GP, LLC, or PVR GP, our general partner.

On March 8, 2010, A. James Dearlove resigned from his position as Chief Executive Officer of PVR GP, and on March 9, 2010, he resigned from his position as President and Chief Executive Officer of PVG GP, LLC ("PVG GP"), the general partner of PVG. On March 8, 2010, the board of directors of PVR GP appointed William H. Shea, Jr. to the position of Chief Executive Officer of PVR GP, and on March 9, 2010 the board of directors of PVG GP appointed Mr. Shea to the positions of President and Chief Executive Officer of PVG GP.

On March 23, 2010, Frank A. Pici resigned from his position as Vice President and Chief Financial Officer of PVR GP, and his position as Vice President and Chief Financial Officer of PVG GP. On March 23, 2010, the board of directors of PVR GP appointed Robert B. Wallace to the position of Executive Vice President and Chief Financial Officer of PVR GP, and the board of directors of PVG GP appointed Mr. Wallace to the position of Executive Vice President and Chief Financial Officer of PVG GP.

On March 31, 2010, A. James Dearlove, Frank A. Pici and Nancy M. Snyder each resigned from their positions as directors on the board of directors of PVR GP. On March 31, 2010, Mr. Shea was appointed as a director on the board of directors of PVR GP and on the board of directors of PVG GP.

On June 7, 2010, Ms. Snyder resigned from her position as Vice President, Chief Administrative Officer, General Counsel and Assistant Secretary of PVR GP. On June 29, 2010 the board of directors of PVR GP appointed Bruce D. Davis, Jr. as Executive Vice President, General Counsel and Secretary of PVR GP.

On September 21, 2010, the Partnership announced that it had entered into an Agreement and Plan of Merger (the "Merger Agreement") by and among the Partnership, PVR GP, PVG, PVG GP, and PVR Radnor, LLC ("Merger Sub"), a wholly owned subsidiary of the Partnership, pursuant to which PVG and PVG GP will be merged into Merger Sub, with Merger Sub as the surviving entity (the "Merger"). Merger Sub will subsequently be merged into our general partner, PVR GP, with PVR GP being the surviving entity. In the transaction, PVG unitholders will receive consideration of 0.98 common units in the Partnership for each common unit in PVG representing aggregate consideration of approximately 38.3 million common units in the Partnership. Pursuant to the Merger Agreement and the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, the incentive distribution rights held by our general partner will be extinguished, the 2.0% general partner interest in the Partnership held by our general partner will be converted into a noneconomic interest and approximately 19.6 million common units in the Partnership owned by PVG will be cancelled.

The terms of the Merger Agreement were unanimously approved by our conflicts committee, comprised of independent directors, of the board of directors of our general partner, by the board of directors of our general partner, by the PVG conflicts committee, comprised of independent directors, of the board of directors of PVG's general partner, and by the board of directors of PVG's general partner (in each case with the chief executive officer of each general partner recusing himself from the board of directors approvals).

Pursuant to the Merger Agreement, PVG agreed to support the Merger by, among other things, voting its Partnership common units in favor of the Merger and against any transaction that, among other things, would materially delay or prevent the consummation of the Merger. The agreement to support automatically terminates if the conflicts committee of the board of directors or the board of directors of the general partner of PVG changes its recommendation to PVG's unitholders with respect to the Merger or the conflicts committee of the board of directors or the board of directors of our general partner changes its recommendation to the Partnership's unitholders with respect to the Merger.

After the Merger, the board of directors of our general partner, PVR GP, is expected to consist of nine members, six of whom are expected to be the existing members of the board and three of whom are expected to be the three existing members of the conflicts committee of the board of directors of PVG's general partner.

The Merger Agreement is subject to customary closing conditions including, among other things, (i) approval by the affirmative vote of the holders of a majority of our common units outstanding and entitled to vote at a meeting of the holders of our common units, (ii) approval by the affirmative vote of the holders of a majority of PVG's common units outstanding and entitled to vote at a meeting of the holders of PVG's common units, (iii) receipt of applicable regulatory approvals, (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance of our common units in connection with the Merger, (v) receipt of certain tax opinions, (vi) approval for listing our common units to be issued in connection with the Merger on the New York Stock Exchange and (vii) the execution of our Fourth Amended and Restated Agreement of Limited Partnership.

Current holders of our common units (the "Partnership unitholders") will continue to own their existing Partnership common units. Following the Merger, we will be owned approximately 46% by current Partnership unitholders and approximately 54% by former PVG unitholders. Our common units will continue to be traded on the New York Stock Exchange under the symbol "PVR" following the Merger.

PVG will be considered the surviving consolidated entity for accounting purposes, while we will be the surviving consolidated entity for legal and reporting purposes. The Merger will be accounted for as an equity transaction. Therefore, the changes in PVG's ownership interest as a result of the Merger will not result in gain or loss recognition.

On February 16, 2011, the Partnership held a special meeting to consider the vote upon the approval and adoption of the Merger and the other transactions contemplated by the Merger Agreement. At the special meeting, two matters were voted on and approved by a majority of the Partnership's unitholders. The first matter voted upon was the approval of the Merger Agreement and the transactions contemplated thereby. 67.52% or 35,308,687 of the Partnership's units outstanding and entitled to vote, voted in favor of this matter. The second matter voted upon was the approval of the Fourth Amended and Restated Partnership Agreement. 67.54% or 35,322,534 of the Partnership's units outstanding and entitled to vote, voted in favor of this matter.

On February 16, 2011, PVG announced that it had adjourned its special meeting of PVG unitholders originally scheduled for February 16, 2011 until March 9, 2011. Prior to the adjournment of the PVG special meeting, 20,688,419 units, or 52.94% of the PVG units outstanding and entitled to vote, voted in favor of the proposal to adjourn the special meeting to a later date to allow further time to solicit additional proxies from PVG unitholders. At the commencement of the PVG special meeting, the proxies received from unitholders totaled 25,353,727 million units, or 64.88% of all PVG units outstanding and entitled to vote. Of the total PVG units outstanding and entitled to vote, proxies representing 39.77% of the PVG units were in favor of the merger proposal. The approval of the Merger Agreement and related transactions requires the affirmative vote of holders of a majority of all units outstanding and entitled to vote. The reconvened PVG special meeting will be held at The Villanova University Conference Center, 601 County Line Road, Radnor, Pennsylvania 19087 on March 9, 2011 at 10:00 AM local time.

2. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of the Partnership and all of our wholly owned subsidiaries. Intercompany balances and transactions have been eliminated in consolidation. We own member interests in three joint ventures that are accounting for under the equity method of accounting and more fully described in Note 8 to the Consolidated Financial Statements. Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America.

Certain reclassifications have been made to conform to the current period's presentation of taxes other than income. Historically, we reported taxes other than income as a separate component of expenses. We have reclassified the components of taxes other than income, which primarily related to property taxes and payroll taxes, to operating expense and general and administrative expense for all periods presented.

Management has evaluated all activities of the Partnership through the date upon which the Consolidated Financial Statements were issued and concluded that no subsequent events have occurred that would require recognition in the Consolidated Financial Statements, but disclosure is required in the Notes to Consolidated Financial Statements. See Note 19 to the Consolidated Financial Statements.

All dollar amounts presented in the tables to these Notes are in thousands unless otherwise indicated.

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 charged to expense 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 balance method over the estimated useful life of each asset as follows:

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

Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by our own geologists and outside consultants. Our estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. 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 using a methodology consistent with the units-of-production method, but that is based on the quantity of timber harvested. 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. When we retire or sell an asset, we remove its cost and related accumulated depreciation and amortization from our consolidated balance sheet. Upon sale, we record the difference between the net book value, net of any assumed asset retirement obligation ("ARO"), and proceeds from disposition as a gain or loss.

Intangible assets are primarily associated with assumed contracts, customer relationships and rights-of-way. These intangible assets are amortized on an accelerated or straight-line basis over periods of up to 20 years, the period in which benefits are derived from the contracts, customer relationships and rights-of-way, and are reviewed for impairment along with their associated property, plant and equipment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. See Note 10, "Intangible Assets, Net," for a more detailed description of our intangible assets.

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. The determination of fair value is based upon regional market and specific facility type information. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. See Note 11, "Asset Retirement Obligations." The long-lived assets for which our AROs are recorded include compressor stations, gathering systems and coal processing plants. The amount of an ARO and the costs capitalized represent 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 a rate commensurate with the risk, which approximates our cost of funds. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed rate, 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 ("DD&A") 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. In some cases, 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 in which we can reasonably determine the settlement dates.

Impairment of Long-Lived Assets

We review long-lived assets to be held and used, including related intangible assets, 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 using a rate commensurate with the risk and remaining life of the asset.

The coal and natural resource management and natural gas midstream segments have completed a number of acquisitions in recent years. See Note 3, "Acquisitions," for a description of the material acquisitions. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, and the resulting amount of goodwill, if any. Changes in operations, further decreases in commodity prices, changes in the business environment or further deteriorations of market conditions could substantially alter management's assumptions and could result in lower estimates of values of acquired assets or of future cash flows. If these events occur, it is reasonably possible that we could incur a significant impairment loss.

Impairment of Goodwill

Goodwill recorded in connection with a business combination is not amortized, but tested for impairment at least annually. Goodwill impairment is determined using a two-step test. The first step of the impairment test is used to identify potential impairment by comparing the fair value of a reporting unit to the book value, including goodwill. If the fair value of a reporting unit exceeds its book value, goodwill of the reporting unit is not considered impaired, and the second step of the impairment test is not required. If the book value of a reporting unit exceeds its fair value, the second step of the impairment test is performed to measure the amount of impairment loss, if any. The second step of the impairment test compares the implied fair value of the reporting unit's goodwill with the book value of that goodwill. If the book value of the reporting unit's goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination. The annual impairment testing is performed in the fourth quarter.

Management uses a number of different criteria when evaluating goodwill for possible impairment. Indicators such as significant decreases in a reporting unit's book value, decreases in cash flows, sustained operating losses, a sustained decrease in market capitalization, adverse changes in the business climate, legal matters, losses of significant customers and new technologies which could accelerate obsolescence of business products are used by management when performing evaluations. We tested goodwill for impairment during the fourth quarter of 2008 and recorded an impairment loss of $31.8 million. As a result of this impairment loss, we did not have a balance in goodwill at December 31, 2008. See Note 9, "Goodwill" for a description of goodwill and the related impairment loss.

Equity Investments

We use the equity method of accounting to account for our 25% member interest in Thunder Creek, as well as our 50% member interest investment in a coal handling joint venture and the Crosspoint gas gathering line, recording the initial investment at cost. Subsequently, the carrying amounts of the investments are increased to reflect our share of income of the investees and capital contributions, and are reduced to reflect our share of losses of the investees or distributions received from the investees as the joint ventures report them. Our share of earnings or losses from Thunder Creek and Crosspoint is included in other revenues on the consolidated statements of income, and our share of earnings and losses from the coal handling joint venture is included in coal services on the consolidated statements of income. Other revenues and coal services revenues also include amortization of the amount of the equity investments that exceed our portion of the underlying equity in net assets. We record this amortization over the life of the contracts acquired in the Thunder Creek acquisition, which is 12 years, and the life of the coal services contracts entered into in connection with the coal handling joint venture, which is 15 years.

Debt Issuance Costs

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

Long-Term Prepaid Minimums

We lease a portion of our reserves from third parties that 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 87% of our consolidated accounts receivable at December 31, 2010 resulted from our natural gas midstream segment and approximately 13% resulted from our coal and natural resource management segment. Approximately 46% of our natural gas midstream segment accounts receivable and 38% of our consolidated accounts receivable at December 31, 2010 related to four natural gas midstream customers. As of December 31, 2010, no receivables were collateralized, and we had recorded a $0.2 million allowance for doubtful accounts in the natural gas midstream segment. No significant uncertainties related to the collectability of amounts owed to us exist in regard to these natural gas midstream customers. These customer concentrations increase our exposure to credit risk on our receivables, since the financial insolvency of these customers could have a significant impact on our results of operations.

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 historically have not 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 historically have not been significant, between the actual amounts ultimately received or paid 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. Other liabilities on the balance sheet also include deferred unearned income from a coal services facility lease, which is recognized as other 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 of our coal handling joint venture 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.

Derivative Instruments

From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas, crude oil and NGL price volatility. The derivative financial instruments, which are placed with financial institutions that we believe are acceptable credit risks, take the form of collars and swaps. All derivative financial instruments are recognized in our consolidated financial statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. 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 do not use hedge accounting for commodity derivatives; thus, the open positions are recorded at fair value with the change in value recorded to earnings.

Because we do not use hedge accounting for our commodity derivatives, we recognize changes in fair value in earnings currently in the derivatives line on the consolidated statements of income. We have experienced and could continue to experience significant changes in the estimate of unrealized derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts. The discontinuation of hedge accounting has no impact on our reported cash flows, although our results of operations are affected by the volatility of mark-to-market gains and losses and changes in fair value, which fluctuate with changes in natural gas, crude oil and NGL prices. These fluctuations could be significant in a volatile pricing environment.

We have also entered into interest rate swaps agreements (the "Interest Rate Swaps") to mitigate our exposure to debt interest expense. During the first quarter of 2009, we discontinued hedge accounting for all of the Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Interest Rate Swaps are recognized in the derivatives line item on our consolidated statements of income. During the year ended December 31, 2010, we reclassified a total of $1.8 million from accumulated other comprehensive income ("AOCI") to earnings related the Interest Rate Swaps. At December 31, 2010, a $0.4 million gain remained in AOCI and will be recognized in the Derivatives line as the Interest Rate Swaps settle. See Note 6, "Derivative Instruments," for a description of our derivative program.

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

Effective January 1, 2009, we adopted the new accounting standard addressing the computation of earnings per unit for master limited partnerships that issue multiple classes of securities that participate in partnerships distribtutions. Our securities consist of publicly traded common units held by limited partners, a general partner interest and separately transferable incentive distribution rights ("IDRs"). This standard requires earnings or losses for a reporting period to be allocated to our limited partners, our general partner and holders of IDRs using the two-class method to compute earnings per unit. Under this method, our net income (or loss) for a reporting period is reduced (or increased) by the amount that has been or will be distributed to our participating security holders. In the event that our net income exceeds our distributions (or our distributions exceed our net income), such excess undistributed net income (or loss) is allocated to our limited partners and our general partner in the ratio of 98% and 2%, as provided in our partnership agreement.

Also, on January 1, 2009, we adopted the new accounting standard which determines whether instruments granted in share-based payments transactions are participating securities. Under this standard, unvested unit-based payment awards that contain non-forfeitable rights to distributions or distribution equivalents are participating securities and, therefore, are included in the computation of net income allocable to limited partners pursuant to the two-class method of computing earnings per unit. During 2010 and 2009, our general partner granted phantom units to employees of our general partner or its affiliates. See Note 15, "Unit-Based Payments." We have determined that our unvested phantom unit awards contain non-forfeitable rights to distributions and, therefore, are participating securities for purposes of this standard.

Basic and diluted net income per limited partner unit is computed by dividing net income allocable to limited partners by the weighted average number of limited partner units outstanding during the period. Diluted net income per limited partner unit is computed by dividing net income allocable to limited partners by the weighted average number of limited partner units outstanding during the period and, when dilutive, phantom units.

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 recognize compensation expense over the vesting period of the awards.

Authoritative accounting literature establishes standards for transactions in which an entity exchanges its equity instruments for goods and services. This standard requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. See Note 15, "Unit-Based Payments," for a more detailed description of our long-term incentive plan.

New Accounting Standards

In January 2010, an accounting standards update ("ASU") was issued that amends certain disclosure requirements. This ASU provides for additional financial instrument fair value disclosures for transfers in and out of Levels I and II and for activity in Level III. This ASU also clarifies certain other existing disclosure requirements including level of desegregation and disclosures around inputs and valuation techniques. This ASU is effective for annual or interim reporting periods beginning after December 15, 2009, except for the requirement to provide the Level III activity for purchases, sales, issuances, and settlements on a gross basis. That requirement is effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The amendments do not require disclosures for earlier periods presented for comparative purposes at initial adoption. The adoption of this amendment did not impact on our financial statements, but may cause us to enhance future disclosures around derivative fair value disclosures.

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 Combinations

Lone Star Gathering, L.P. ("Lone Star")

On July 17, 2008, we completed an acquisition of substantially all of the assets of Lone Star. Lone Star's assets are located in the southern portion of the Fort Worth Basin of North Texas and include approximately 129 miles of gas gathering pipelines and approximately 240,000 acres dedicated by active producers. The Lone Star acquisition expanded the geographic scope of the natural gas midstream segment into the Barnett Shale play in the Fort Worth Basin.

We acquired this business for approximately $164.3 million and a liability of $4.7 million, which represents the fair value of a $5.0 million guaranteed payment, plus contingent payments of $30.0 million and $25.0 million. Funding for the acquisition was provided by $80.7 million of borrowings under our revolving credit facility (the "Revolver"), 2,009,995 PVG common units (which we purchased from two subsidiaries of Penn Virginia for $61.8 million) and 542,610 of our newly issued common units.

The contingent payments will be triggered if revenues from certain assets located in a defined geographic area reach certain targets by or before June 30, 2013 and will be funded in cash or common units, at our election.

The Lone Star acquisition has been accounted for using the purchase method of accounting. Under the purchase method of accounting, the total purchase price has been allocated to the net tangible and intangible assets acquired from Lone Star based on their estimated fair values. The total purchase price was allocated to the assets purchased based upon fair values on the date of the Lone Star acquisition as follows:

Cash consideration paid for Lone Star	$	81,125
Fair value of PVG common units given as consideration for Lone Star		68,021
Fair value of PVR common units issued and given as consideration for Lone Star		15,171
Contingency payment		4,673
Total purchase price	$	168,990
Fair value of assets acquired:		
Property and equipment	$	88,596
Intangible assets		69,200
Goodwill		11,194
Fair value of assets acquired	$	168,990

The purchase price included approximately $11.2 million of goodwill, all of which was allocated to the natural gas midstream segment. A significant factor that contributed to the recognition of goodwill was the ability to acquire an established business on the western border of the expanding Barnett Shale play in the Fort Worth Basin. In accordance with goodwill and other intangible assets accounting standards, goodwill recorded in connection with a business combination is not amortized, but is tested for impairment at least annually. Accordingly, the accompanying pro forma combined income statement does not include amortization of the goodwill recorded in the acquisition. As a result of testing goodwill for impairment in the fourth quarter of 2008, we recognized a loss on impairment of goodwill. See Note 9, "Goodwill" for a description of our goodwill impairment.

The purchase price includes approximately $69.2 million of intangible assets that are associated with assumed contracts and customer relationships. These intangible assets will be amortized over the period in which benefits are derived from the contracts and relationships assumed and will be reviewed for impairment along with the related tangible assets. Based on when the estimated economic benefit will be earned, we estimate the useful lives of these intangible assets to be 20 years. See Note 10, "Intangible Assets, Net."

The following pro forma financial information reflects the consolidated results of our operations as if the Lone Star acquisition had occurred on January 1, 2007. The pro forma information includes adjustments primarily for depreciation of acquired property and equipment, the amortization of intangible assets, interest expense for acquisition debt and the change in weighted average common units resulting from the issuance of 542,610 of our newly issued common units given as consideration in the Lone Star acquisition. 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 (in thousands, except per unit data):

		December 31 2008
Revenues	$	885,147
Net income	$	93,363
Net income per limited partner unit, basic & diluted	$	1.41

Other Miscellaneous Acquisitions

In 2010 we completed two acquisitions of coal mineral reserves for approximately $24.7 million. In 2009 we completed two natural gas midstream acquisitions for approximately $27.5 million. Funding for all these transactions was provided by borrowing under our Revolver. The pro forma result for the years ended December 31, 2010 and 2009 for the above acquisitions did not materially change the historical results for those periods.

4. Unit Offering

In 2008, we issued 5.15 million common units to the public representing limited partner interests and received $138.2 million in net proceeds. We received total contributions of $2.9 million from our general partner to maintain its indirect 2% general partner interest. We used net proceeds to repay a portion of our borrowings under the Revolver.

5. Fair Value Measurement of Financial Instruments

We present fair value measurements and disclosures applicable to both our financial and nonfinancial assets and liabilities that are measured and reported on a fair value basis. Our financial instruments that are subject to fair value disclosures consist of cash and cash equivalents, accounts receivable, accounts payable, derivative instruments and long-term debt. At December 31, 2010, the carrying values of all these financial instruments, except the long-term debt with fixed interest rates, approximated their fair value. The fair value of floating-rate debt approximates the carrying amount because the interest rates paid are based on short-term maturities. The fair value of our fixed-rate debt is estimated based on the published market prices for the same or similar issues. As of December 31, 2010, the fair value of our fixed-rate debt was $310.5 million.

Authoritative accounting literature requires fair value measurements to be classified and disclosed in one of the following three categories:

- *Level 1:* Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- *Level 2:* Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- *Level 3:* Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

Nonrecurring Fair Value Measurements

We have completed a number of acquisitions in recent years. See Note 3, "Acquisitions," for a description of our coal and natural resource management and natural gas midstream segment's material acquisitions. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions in 2010, and the ones requiring the most judgment, involved the estimated fair values of coal minerals and the timing of permitting and production activities. The coal mineral acquisitions included nonfinancial assets that were measured at fair value during 2010. The total purchase price allocation was $9.8 million. Regarding the coal mineral acquisition, which included contingency payments, the contingent purchase consideration was recorded at its anticipated fair value on the date of acquisition. Any difference between the actual contingent purchase consideration and the original fair value estimate is recorded in earnings when the contingency is eventually resolved. There are three triggering events that can impact contingent purchase consideration. Outside appraisers conducted due diligence with PVR's Manager of Development for West Virginia Properties, as well as outside parties, to assess the prospects of the various trigger events of permitting, and thereafter milestones of slope and shaft completion and eventually tonnage production rates being realized. Based on discussions with management, and considering that this is a deep mining permit and not the more currently troubled permitting process of mountaintop mining, a success factor of 80% probability was assigned to the permitted phase of purchase consideration. Given that the other two triggering events are clearly linked to the successful permitting event, an 80% factor was applied as well.

The following table summarizes the initial fair value estimates for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis by category during 2010:

		Fair Value Measurements Using		
	Fair Value Measurements at December 31, 2010	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Description				
Northern Appalachia coal reserves......	$ 9,765	$ -	$ -	$ 9,765
Total..	$ 9,765	$ -	$ -	$ 9,765

In conjunction with our 2009 accounting for acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, AROs and the resulting amount of goodwill, if any. The Sweetwater plant acquisition included nonfinancial assets and liabilities that were measured at fair value during 2009. The cost approach was used to develop the fair values of the Sweetwater plant assets. The cost approach is a technique that uses the reproduction or replacement cost as an initial basis for value. The cost to reproduce or replace the subject asset with a new asset, either identical (reproduction) or having the same utility (replacement), establishes the highest amount a prudent investor is likely to pay. A series of models were used to value the Sweetwater plant and related pipelines. Salient data points for the model included capacities of the processing plant, processing technology, and size and length of pipeline. To the extent that the asset being valued provides less utility than a new one, due to physical deterioration, functional obsolescence, and/or economic obsolescence, the value of the subject asset is adjusted for those reductions in value. Adjustments may be made for age, physical wear and tear, technological inefficiencies, changes in price levels, and reduced demand, among other factors. Related to the Sweetwater plant assets, an ARO liability was recognized. See Note 2, "Summary of Significant Accounting Policies" for a description of the inputs and techniques used to derive ARO fair values. The following table summarizes the initial fair value estimates for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis by category during 2009:

		Fair Value Measurements, Using		
Description	**Fair Value Measurements at December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Sweetwater plant PP&E-noncurrent assets	$ 22,772	$ -	$ -	$ 22,772
Sweetwater plant ARO-noncurrent liabilities	(208)	-	-	(208)
Total	$ 22,564	$ -	$ -	$ 22,564

Recurring Fair Value Measurements

The following table summarizes the assets and liabilities measured at fair value on a recurring basis and included our derivative financial instruments by categories as of December 31, 2010 and 2009:

		Fair Value Measurements at December 31, 2010 Using		
Description	**Fair Value Measurements at December 31, 2010**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Interest rate swap liabilities - current	$ (7,647)	-	$ (7,647)	-
Interest rate swap liabilities - noncurrent	(1,037)	-	(1,037)	-
Commodity derivative liabilities - current	(11,869)	-	(11,869)	-
Commodity derivative liabilities - noncurrent	(4,070)	-	(4,070)	-
Total	$ (24,623)	$ -	$ (24,623)	$ -

Description	Fair Value Measurements at December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Fair Value Measurements at December 31, 2009 Using		
Interest rate swap assets - noncurrent	$ 1,266	$ -	$ 1,266	$ -
Interest rate swap liabilities - current	(7,710)	-	(7,710)	-
Interest rate swap liabilities - noncurrent	(3,241)	-	(3,241)	-
Commodity derivative assets - current	1,331	-	1,331	-
Commodity derivative assets - noncurrent	18	-	18	-
Commodity derivative liabilities - current	(3,541)	-	(3,541)	-
Commodity derivative liabilities - noncurrent	(1,044)	-	(1,044)	-
Total	$ (12,921)	$ -	$ (12,921)	$ -

The values of both the Interest Rate Swap and commodity derivatives are presented in the derivative assets and derivative liabilities line items on the consolidated balance sheets.

See Note 6, "Derivative Instruments," for the effects of these instruments on our consolidated statements of income.

We use the following methods and assumptions to estimate the fair values in the above table:

- *Commodity derivative instruments*: We utilize collars and swap derivative contracts to hedge against the variability in the fractionation, or frac, spread. We determine the fair values of our commodity derivative agreements based on discounted cash flows based on quoted forward prices for the respective commodities. Each is a level 2 input. We use the income approach, using valuation techniques that convert future cash flows to a single discounted value. See Note 6, "Derivative Instruments."
- *Interest rate swaps*: We have entered into the Interest Rate Swaps to establish fixed rates on a portion of the outstanding borrowings under the Revolver. We use an income approach using valuation techniques that connect future cash flows to a single discounted value. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. Each is a level 2 input. See Note 6, "Derivative Instruments."

6. Derivative Instruments

Natural Gas Midstream Segment Commodity Derivatives

We utilize costless collars and swap derivative contracts to hedge against the variability in cash flows associated with anticipated natural gas midstream revenues and cost of midstream gas purchased. We also utilize collar 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 NGLs that we sell after processing. We hedge against the variability in our frac spread by entering into costless collar and swap derivative contracts to sell NGLs forward at a predetermined commodity 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, such use may also 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 Put (or floor) price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the Call (or 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 for the purchase of a commodity, the counterparty is required to make a payment to us if the settlement price for any settlement period is greater than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price is less than the swap price for such contract.

We determine the fair values of our derivative agreements by discounting the cash flows based on quoted forward prices for the respective commodities as of December 31, 2010, using discount rates adjusted for the credit risk of the counterparties if the derivative is in an asset position and our own credit risk for derivatives in a liability position. The following table sets forth our positions as of December 31, 2010 for commodities related to natural gas midstream revenues and cost of midstream gas purchased:

	Average Volume Per Day	Swap Price	Weighted Average Price Put	Weighted Average Price Call	Fair Value at December 31, 2010
					(in thousands)
NGL - natural gasoline collar	(gallons)		(per gallon)		
First quarter 2011 through fourth quarter 2011	95,000		$1.57	$1.94	$ (7,924)
Crude oil collar	(barrels)		(per barrel)		
First quarter 2011 through fourth quarter 2011	400		$75.00	$98.50	(475)
Natural gas purchase swap	(MMBtu)	(MMBtu)			
First quarter 2011 through fourth quarter 2011	6,500	$5.80			(2,909)
NGL - natural gasoline collar	(gallons)		(per gallon)		
First quarter 2012 through fourth quarter 2012	54,000		$1.75	$2.02	(2,802)
Crude oil swap	(barrels)	(per barrel)			
First quarter 2012 through fourth quarter 2012	600	$88.62			(1,106)
Natural gas purchase swap	(MMBtu)	(MMBtu)			
First quarter 2012 through fourth quarter 2012	4,000	$5.195			(162)
Settlements to be paid in subsequent period					(561)

At December 31, 2010, we reported a net derivative liability related to the natural gas midstream segment of $15.9 million. No amounts remain in AOCI as of December 31, 2010 or 2009 related to derivatives in the natural gas midstream segment for which we discontinued hedge accounting in 2006, and no amounts have been recorded to AOCI related to the derivative positions as of December 31, 2010.

Interest Rate Swaps

We have entered into the Interest Rate Swaps to establish fixed rates on a portion of the outstanding borrowings under the Revolver. From March 2010 to December 2011, the notional amounts of the Interest Rate Swaps total $250.0 million with us paying a weighted average fixed rate of 3.37% on the notional amount, and the counterparties paying a variable rate equal to the three-month London Interbank Offered Rate ("LIBOR"). From December 2011 to December 2012, the notional amounts of the Interest Rate Swaps total $100.0 million, with us paying a weighted average fixed rate of 2.09% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. The Interest Rate Swaps have been entered into with six financial institution counterparties, with no counterparty having more than 30% of the open positions. The following table sets forth our positions as of December 31, 2010 for the Interest Rate Swaps:

Term	Notional Amounts (in millions)	Swap Interest Rates Pay	Swap Interest Rates Receive	Fair Value at December 31, 2010
March 2010 - December 2011	$250.0	3.37%	LIBOR	$ (7,647)
December 2011 - December 2012	$100.0	2.09%	LIBOR	$ (1,037)

During the first quarter of 2009, we discontinued hedge accounting for all of the Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Interest Rate Swaps have been recognized in earnings on our consolidated statements of income. At December 31, 2010, a $0.4 million gain remained in AOCI related to the Interest Rate Swaps. The $0.4 million gain will be recognized in the derivatives line as the original forecasted interest payments occur.

We reported a (i) net derivative liability of $8.7 million at December 31, 2010 and (ii) gain in AOCI of $0.4 million at December 31, 2010 related to the Interest Rate Swaps. In connection with periodic settlements, we recognized $1.8 million of net hedging losses in interest expense and the derivatives line in the year ended December 31, 2010. Based upon future interest rate curves at December 31, 2010, we expect to realize $7.6 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.

Financial Statement Impact of Derivatives

The following table summarizes the effects of our derivative activities, as well as the location of the gains and losses, on our consolidated statements of income for the periods presented:

	Location of gain (loss) on derivatives recognized in income	Year Ended December 31, 2010	2009	2008
Derivatives not designated as hedging instruments:				
Commodity contracts (1)	Natural gas midstream revenues	$ -	$ -	$ (8,219)
Commodity contracts (1)	Cost of midstream gas purchased	-	-	2,739
Interest rate contracts (2)	Interest expense	(1,090)	(3,356)	(1,706)
Interest rate contracts	Derivatives	(7,930)	(4,306)	(8,635)
Commodity contracts	Derivatives	(14,563)	(15,408)	25,472
Total decrease in net income resulting from derivatives		$ (23,583)	$ (23,070)	$ 9,651
Realized and unrealized derivative impact:				
Cash received (paid) for commodity and interest rate contract settlements	Derivatives	$ (10,075)	$ 3,000	$ (38,466)
Cash paid for interest rate contract settlements	Interest expense	-	(370)	(503)
Unrealized derivative losses (3)		(13,508)	(25,700)	48,620
Total decrease in net income resulting from derivatives		$ (23,583)	$ (23,070)	$ 9,651

(1) This represents commodity derivative amounts reclassified out of AOCI and into earnings. Subsequent to the discontinuation of hedge accounting for commodity derivatives in 2006, amounts remaining in AOCI have been reclassified into earnings in the same period or periods during which the original hedge forecasted transaction affects earnings. No losses remain in AOCI related to commodity derivatives for which we discontinued hedge accounting in 2006.

(2) This represents Interest Rate Swap amounts reclassified out of AOCI and into earnings. During 2008 and 2009 we discontinued hedge accounting for various Interest Rate Swaps at different times. By the first quarter of 2009 we discontinued hedge accounting for the remaining Interest Rate Swaps. During 2009 and 2008 we reclassified $0.4 million and $0.5 million out of AOCI relating to actual hedge settlements accounted for under hedge accounting. During 2010, 2009 and 2008 we reclassified $1.8 million, $3.0 million and $1.2 million for remaining AOCI that have been reclassified into earnings in the same period or periods relating to Interest Rate Swaps not designated for hedge accounting.

(3) This activity represents unrealized gains in the natural gas midstream, cost of midstream gas purchased, interest expense and derivatives lines on our consolidated statements of income.

The following table summarizes the fair value of our derivative instruments, as well as the locations of these instruments on our consolidated balance sheets as of December 31, 2010 and 2009:

	Balance Sheet Location	Fair values as of December 31, 2010 Derivative Assets	Fair values as of December 31, 2010 Derivative Liabilities	Fair values as of December 31, 2009 Derivative Assets	Fair values as of December 31, 2009 Derivative Liabilities
Derivatives not designated as hedging instruments:					
Interest rate contracts (1)......	Derivative assets/liabilities - current	$ -	$ 7,647	$ -	$ 7,710
Interest rate contracts (1)......	Derivative assets/liabilities - noncurrent	-	1,037	1,266	3,241
Commodity contracts	Derivative assets/liabilities - current	-	11,869	1,331	3,541
Commodity contracts	Derivative assets/liabilities - noncurrent	-	4,070	18	1,044
Total derivatives not designated as hedging instruments		$ -	$ 24,623	$ 2,615	$ 15,536
Total fair value of derivative instruments		$ -	$ 24,623	$ 2,615	$ 15,536

(1) During 2009 and 2008 we discontinued hedge accounting for various Interest Rate Swaps at different times. By the first quarter of 2009 we discontinued hedge accounting for the remaining Interest Rate Swaps. For presentation purposes all Interest Rate Swaps are shown as not designated as hedging instruments for periods presented, 2010 and 2009, reflecting their accounting status as of December 31, 2010.

See Note 5, "Fair Value Measurement of Financial Instruments" for a description of how the above financial instruments are valued.

The following table summarizes the effect of the Interest Rate Swaps on our total interest expense for the periods presented:

Source	Year Ended December 31, 2010	2009	2008
Interest on Borrowings	$ 34,892	$ 21,523	$ 23,641
Interest rate swaps............	1,090	3,356	1,706
Capitalized interest (1)............	(391)	(226)	(675)
Total interest expense	$ 35,591	$ 24,653	$ 24,672

(1) Capitalized interest was primarily related to the construction of our natural gas gathering facilities.

The effects of derivative gains (losses), cash settlements of our natural gas midstream commodity derivatives and cash settlements of the Interest Rate Swaps are reported as adjustments to reconcile net income to net cash provided by operating activities on our consolidated statements of cash flows. We no longer utilize hedge accounting treatment for commodity or interest rate swap derivatives. These items are recorded in the "Total derivative losses (gains)" and "Cash receipts (payments) to settle derivatives" lines on the consolidated statements of cash flows.

The above hedging activity represents cash flow hedges. As of December 31, 2010, we did not own derivative instruments that were classified as fair value hedges or trading securities. In addition, as of December 31, 2010, we did not own derivative instruments containing credit risk contingencies.

7. Property and Equipment

The following table summarizes our property and equipment as of December 31, 2010 and 2009:

	As of December 31,	
	2010	2009
Coal properties	$ 506,235	$ 478,803
Timber	87,699	87,869
Oil and gas royalties	36,937	36,937
Coal services equipment	35,310	38,474
Gathering systems	458,999	372,550
Compressor stations	77,909	62,701
Processing plants	61,665	55,948
Land	20,743	20,743
Other property, plant and equipment	9,730	8,045
Total property, plant and equipment	1,295,227	1,162,070
Accumulated depreciation, depletion and amortization	(324,181)	(261,226)
Net property, plant and equipment	$ 971,046	$ 900,844

8. Equity Investments

We own a 50% interest in Coal Handling Solutions LLC, a joint venture formed to own and operate end-user coal handling facilities. In 2008, we acquired a 25% member interest in Thunder Creek Gas Services LLC, a joint venture that gathers and transports coalbed methane gas in Wyoming's Powder River Basin for $51.6 million in cash, after customary closing adjustments. See Note 3, "Acquisitions." We also own a 50% member interest in Crosspoint Pipeline LLC, a joint venture that gathers residue gas from our Crossroads Plant and transports it to market. We account for these investments under the equity method of accounting. As of December 31, 2010 and 2009, our equity investment totaled $84.3 million and $87.6 million, which exceeded our portion of the underlying equity in net assets by $16.0 million and $18.4 million. The difference is being amortized to equity earnings over the estimated life of the intangible assets at the time of the acquisition. The intangible assets relate to contracts and customer relationships acquired, which are estimated to be from 12 years to 15 years.

In accordance with the equity method of accounting, we recognized equity earnings of $8.7 million in 2010, $7.3 million in 2009 and $4.2 million in 2008, with a corresponding increase in the investment. The joint ventures generally pay quarterly distributions on their cash flow. We received distributions of $12.0 million in 2010, $4.7 million in 2009 and $4.0 million in 2008. Equity earnings related to our 50% interest in Coal Handling Solutions LLC are included in coal services revenues, and equity earnings related to our 25% interest in Thunder Creek and our 50% interest in Crosspoint are recorded in other revenues on the Consolidated Statements of Income. The equity investments for all joint ventures are included in the equity investments caption on the Consolidated Balance Sheets.

Summarized financial information of unconsolidated equity investments is as follows for the periods presented:

	As of December 31,	
	2010	2009
Current assets	$ 43,367	$ 32,996
Noncurrent assets	$ 203,595	$ 214,463
Current liabilities	$ 6,890	$ 4,898
Noncurrent liabilities	$ 5,147	$ 5,392

	Year Ended December 31,		
	2010	2009	2008
Revenues	$ 69,302	$ 68,106	$ 43,687
Expenses	$ 33,782	$ 34,916	$ 25,204
Net income	$ 35,520	$ 33,190	$ 18,483

9. Goodwill

Goodwill is tested for impairment on an annual basis, at a minimum, and more frequently if a triggering event occurs. Our 2008 annual impairment testing of goodwill and other intangible assets resulted in an impairment to goodwill of approximately $31.8 million in the fourth quarter of 2008. The impairment loss, which was triggered by fourth quarter declines in oil and gas spot and futures prices and a decline in our market capitalization, reduced to zero all goodwill recorded in conjunction with acquisitions made by the natural gas midstream segment in 2008 and prior years.

In determining the fair value of the natural gas midstream segment (reporting unit), we used an income approach. Under the income approach, the fair value of the reporting unit is estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, appropriate discount rates and a market derived earnings multiple terminal value (the value of the reporting unit at the end of the estimation period).

Key assumptions used in the discounted cash flows model described above include estimates of future commodity prices based on the December 31, 2008 commodity price strips and estimates of operating, administrative and capital costs. We discounted the resulting future cash flows using a peer company based weighted average cost of capital of 12%.

This loss was recorded in the impairment line on our consolidated statements of income. The goodwill impairment loss reflects the negative impact of certain factors which resulted in a reduction in the anticipated cash flows used to estimate fair value. The business and marketplace environments in which we currently operate differs from the historical environments that drove the factors used to value and record the acquisition of these business units. There is no goodwill balance as of December 31, 2010 and 2009.

10. Intangible Assets, Net

The following table summarizes our net intangible assets as of December 31, 2010 and 2009:

	As of December 31,	
	2010	2009
Contracts and customer relationships	$ 104,700	$ 104,700
Rights-of-way	4,552	4,552
Total intangible assets	109,252	109,252
Accumulated amortization	(32,302)	(25,511)
Intangible assets, net	$ 76,950	$ 83,741

The contracts and customer relationships and rights-of-way were primarily acquired in the Lone Star acquisition. See Note 3, "Acquisitions." Contracts and customer relationships are amortized on both a straight-line basis and an accelerated depreciation basis, based on the period and timing of the benefit to us, over the expected useful lives of the individual contracts and relationships, up to 20 years. Total intangible amortization expense for the years ended December 31, 2010, 2009 and 2008 was approximately $6.7 million, $7.4 million and $5.5 million. The following table sets forth our estimated aggregate amortization expense for the next five years and thereafter:

Year	Amortization Expense
2011	6,285
2012	5,718
2013	5,499
2014	5,346
2015	5,233
Thereafter	48,869
Total	$ 76,950

11. Asset Retirement Obligations

The following table reconciles the beginning and ending aggregate carrying amount of our asset retirement obligations for the years ended December 31, 2010 and 2009, which are recorded in other liabilities on our consolidated balance sheets:

	Year Ended December 31,	
	2010	2009
Balance at beginning of period	$ 2,014	$ 1,814
Liabilities incurred	-	208
Accretion expense	158	(8)
Revision of estimate	-	-
Balance at end of period	$ 2,172	$ 2,014

The accretion expense is recorded in the depreciation, depletion and amortization expense line on the consolidated statements of income.

12. Long-Term Debt

The following table summarizes our long-term debt as of December 31, 2010 and 2009 (in thousands):

	As of December 31,	
	2010	2009
Revolver – variable rate of 2.9% and 2.5% at December 31, 2010 and 2009	$ 408,000	$ 620,100
Senior notes - fixed rate of 8.25%	300,000	-
Total debt	708,000	620,100
Less: Current maturities	-	-
Total long-term debt	$ 708,000	$ 620,100

We capitalized interest costs amounting to $0.4 million and $0.2 million in the years ended December 31, 2010 and 2009 related to the construction of natural gas processing plants.

Revolver

On August 13, 2010, we entered into an amended and restated secured credit agreement increasing our borrowing capacity under the Revolver to $850 million. As of December 31, 2010, net of outstanding indebtedness of $408.0 million and letters of credit of $1.6 million, we had remaining borrowing capacity of $440.4 million on the Revolver. The Revolver matures August 13, 2015. The Revolver includes a $10 million sublimit for the issuance of letters of credit and a $25 million sublimit for swingline borrowings. We have an option, subject to the acceptance by the bank group, to increase the commitments under the Revolver by up to an additional $200 million, to a total of $1.05 billion. The Revolver is available to provide funds for general partnership purposes, including working capital, capital expenditures, acquisitions and quarterly distributions. In 2010, we incurred commitment fees of $1.2 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 base rate plus an applicable margin ranging from 1.25% to 2.25% if we select the base rate indebtedness option under the Revolver or at a rate derived from LIBOR plus and applicable margin ranging from 2.25% to 3.25% if we select the LIBOR-based indebtedness option. The weighted average interest rate on borrowings outstanding under the Revolver during 2010 was approximately 2.5%. We do not have a public rating for the Revolver. As of December 31, 2010, we were in compliance with all of our covenants under the Revolver.

Senior Notes

In April 2010, we sold $300.0 million of senior notes due on April 15, 2018 with an annual interest rate of 8.25% ("Senior Notes), which is payable semi-annually in arrears on April 15 and October 15 of each year. The Senior Notes were sold at par, equating to an effective yield to maturity of approximately 8.25%. The net proceeds from the sale of the Senior Notes of approximately $292.6 million, after deducting fees and expenses of approximately $7.4 million, were used to repay borrowings under the Revolver. The Senior Notes are senior to any subordinated indebtedness, and are effectively subordinated to all of our secured indebtedness including the Revolver to the extent of the collateral securing that indebtedness. The obligations under the Senior Notes are fully and unconditionally guaranteed by our current and future subsidiaries, which are also guarantors under the Revolver.

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 (in thousands):

Year	Aggregate Maturities Principal Amounts
2011	$ -
2012	-
2013	-
2014	-
2015	408,000
Thereafter	300,000
Total debt, including current maturities	$ 708,000

13. Partners' Capital and Distributions

As of December 31, 2010, partners' capital consisted of 52.3 million common units, representing a 98% limited partner interest and a 2% general partner interest. As of December 31, 2010, PVG, in the aggregate, owned a 39% interest in us, consisting of 19.6 million common units and a 2% general partner interest.

Net Income per Limited Partner Unit

Our securities consist of publicly traded common units held by limited partners, a general partner interest and separately transferable incentive distribution rights ("IDRs"). The earnings or losses for a reporting period are allocated to our limited partners, our general partner and holders of IDRs using the two-class method to compute earnings per unit. Under this method, our net income (or loss) for a reporting period is reduced (or increased) by the amount that has been or will be distributed to our participating security holders. In the event that our net income exceeds our distributions (or our distributions exceed our net income), such excess undistributed net income (or loss) is allocated to our limited partners and our general partner in the ratio of 98% and 2%, as provided in our partnership agreement.

Additionally, we have unvested unit-based payment awards that contain non-forfeitable rights to distributions or distribution equivalents are participating securities and, therefore, are included in the computation of net income allocable to limited partners pursuant to the two-class method of computing earnings per unit. During the years ended December 31, 2010 and 2009, our general partner granted phantom units to employees of our general partner or its affiliates. We have determined that our unvested phantom unit awards contain non-forfeitable rights to distributions and, therefore, are participating securities.

Basic and diluted net income per limited partner unit is computed by dividing net income allocable to limited partners by the weighted average number of limited partner units outstanding during the period. Diluted net income per limited partner unit is computed by dividing net income allocable to limited partners by the weighted average number of limited partner units outstanding during the period and, when dilutive, phantom units. For the years ended December 31, 2010 and 2009 the average awards of 113,000 and 151,000 phantom units were excluded from the diluted net income per limited partner unit calculation because the inclusion of these phantom units would have had an antidilutive effect.

The following table reconciles net income and weighted average units used in computing basic and diluted net income per limited partner unit (in thousands, except per unit data):

	Year Ended December 31,		
	2010	2009	2008
Net income	$ 68,458	$ 65,215	$ 104,500
Adjustments:			
Distributions payable on account of incentive distribution rights	(24,325)	(24,140)	(22,067)
Distributions payable on account of general partner interest	(2,004)	(1,988)	(1,903)
General partner interest in excess of distributions over earnings allocable to the general partner interest	1,120	1,166	255
Net income allocable to limited partners and participating securities	$ 43,249	$ 40,253	$ 80,785
Adjustments:			
Distributions to participating securities	(434)	(664)	-
Participating securities' allocable share of net income	244	(210)	-
Net income allocable to limited partners	$ 43,059	$ 39,379	$ 80,785
Weighted average limited partner units, basic and diluted	52,094	51,799	49,495
Net income per limited partner unit, basic and diluted	$ 0.83	$ 0.76	$ 1.63

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, 2010, 2009 and 2008 (in thousands, except per unit data):

	Year Ended December 31,		
	2010	2009	2008
Limited partner units	$ 97,889	$ 97,382	$ 89,207
General partner interest (2%)	1,999	1,988	1,820
Incentive distribution rights	24,267	24,140	20,049
Phantom units	440	499	-
Total cash distributions paid	$ 124,595	$ 124,009	$ 111,076
Total cash distributions paid per limited partner unit	$ 1.88	$ 1.88	$ 1.82

On February 14, 2011, we paid a $0.47 quarterly distribution per unit to unitholders of record on February 7, 2010. This distribution was unchanged from the previous distribution paid on November 12, 2010.

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 acquire 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 equal to the greater of (i) 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 (ii) 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.

14. Related Party Transactions

In June 2010, PVA sold its remaining interest in PVG and as a result, PVA no longer owns any limited or general partner interests in us or PVG. As a result of the divestiture, the related party transactions noted below are now considered arm's-length and no longer require separate disclosures. PVA and PVG executed a transition agreement covering the services of certain shared employees, aiding the transition of corporate and accounting functions that could continue until March 2011. Related party transactions included charges from PVA for certain corporate administrative expenses which are allocable to us and our subsidiaries. Other transactions involved subsidiaries of PVA related to the marketing of natural gas, gathering and processing of natural gas, and the purchase and sale of natural gas and NGLs in which we took title to the products. The Consolidated Statements of Income and Consolidated Balance Sheet amounts noted below represent related party transactions through June 7, 2010 (date of divestiture).

	Year ended December 31, 2010	2009	2008
Consolidated Statements of Income:			
Natural gas midstream revenues	$ 29,002	$ 76,573	$ 130,220
Other income	$ 787	$ 1,418	$ 3,014
Cost of gas purchased	$ 27,780	$ 72,529	$ 127,907
General and administrative	$ 1,773	$ 5,315	$ 5,143

	December 31, 2010	December 31, 2009
Consolidated Balance Sheets:		
Accounts receivable	$ -	$ 674
Accounts payable	$ -	$ 7,889

General and Administrative

As we do not have any employees, our general partner and its affiliates employ and pay the employees to carry out our operations. We reimburse our general partner for these costs, which primarily relate to salaries and benefits. As of December 31, 2010, we owed the general partner $1.6 million for such costs.

15. Unit-Based Payments

Long-Term Incentive Plan

Authoritative accounting literature establishes standards for transactions in which an entity exchanges its equity instruments for goods and services. These standards requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award.

As of December 31, 2010, the Partnership had the Penn Virginia Resource GP, LLC Fifth Amended and Restated Long-Term Incentive Plan ("LTIP") which is administered by the Compensation and Benefits Committee (the "Committee") of our general partner, Penn Virginia Resource GP, LLC, and is intended to promote the interest of the Partnership. The LTIP permitted the grant of awards covering an aggregate of 3,000,000 common units to employees and directors of our general partner and employees of its affiliates who perform services for us.

Awards under the LTIP can be in the form of common units, restricted units, unit options, phantom units and deferred common units. We recognize compensation cost based on the fair value of the awards evenly over the vesting period.

We recognized a total of $8.0 million, $4.8 million and $3.2 million in the years ended December 31, 2010, 2009 and 2008 of compensation expense related to the granting of common units and deferred common units and the vesting of restricted and phantom units granted under the LTIP. These expenses are recorded on the general and administrative expense line on our consolidated statements of income.

Common Units. Our general partner granted 1,448 common units at a weighted average grant-date fair value of $23.41 per unit to non-employee directors in 2010. Our general partner granted 1,871 common units at a weighted average grant-date fair value of $15.46 per unit to non-employee directors in 2009. Our general partner granted 1,525 common units at a weighted average grant-date fair value of $20.27 per unit to non-employee directors in 2008. The fair value of the common units is calculated based on the grant-date unit price.

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.

The following is a summary of deferred common unit activity for the periods presented:

	Number of Deferred Common Units	Weighted Average Grant-Date Fair Value
Balance at January 1, 2008	61,218	$25.68
Granted and vested	30,951	$20.36
Converted to common units	(28,600)	$23.70
Balance at December 31, 2008	63,569	$23.98
Granted and vested	35,819	$15.62
Balance at December 31, 2009	99,388	$20.97
Granted and vested	27,194	$24.00
Balance at December 31, 2010	126,582	$21.62

In 2008, 28,600 deferred common units converted to common units. The aggregate intrinsic value of deferred common units converted to common units in 2008 was $0.7 million. The aggregate intrinsic value of vested deferred common units at December 31, 2010, was $2.7 million. The fair value of the deferred common units is calculated based on the grant-date unit price.

Restricted Units. Restricted units vest upon terms established by the 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 Committee provides otherwise. Distributions payable with respect to restricted units may, in the 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 fair value of the restricted units is calculated based on the grant-date unit price.

Because PVA's divestiture of PVG was considered a change of control under the LTIP, all unvested restricted units granted to employees performing services for the benefit of us were considered vested on the date of the divestiture. In total, approximately 36,000 restricted units vested and the restrictions were lifted.

The following table summarizes the status of our nonvested restricted units as of December 31, 2010 and changes during the year then ended:

	Nonvested Restricted Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2010	92,809	$26.57
Vested	(90,550)	$26.89
Forfeited	(2,259)	$26.91
Nonvested at December 31, 2010	-	$ -

The total grant-date fair value of restricted units that vested in 2010, 2009 and 2008 was $2.4 million, $3.5 million and $1.9 million.

Phantom Units. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the Committee, the cash equivalent of the value of a common unit. The Committee determines 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. If a director's membership on the board of directors of our general partner terminates for any reason, or an employee's employment with our general partner and its affiliates terminates for any reason other than retirement after reaching age 62 and completing 10 years of consecutive service, the grantee's phantom units will be automatically forfeited unless, and to the extent, the Committee provides otherwise. Phantom units were first granted in 2009. Phantom units generally vest over a three-year period, with one-third vesting in each year. The fair value of the phantom units is calculated based on the grant-date unit price. Generally, we pay distributions for all of our unvested phantom units. Payments of distribution associated with phantom units that are expected to vest are recorded as capital distributions; however, payments associated with phanotm units that are not expected to vest are recorded as compensation expense.

The following table summarizes the status of our nonvested phantom units as of December 31, 2010 and changes during the year then ended:

	Nonvested Phantom Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2010	277,003	$11.59
Granted	261,262	$23.41
Vested	(419,076)	$15.87
Forfeit	(21,456)	$15.88
Nonvested at December 31, 2010	97,733	$23.91

At December 31, 2010, we had $1.9 million of total unrecognized compensation cost related to nonvested phantom units. We expect to reimburse our general partner for that cost over a weighted-average period of 2.6 years. The total grant-date fair value of phantom units that vested in 2010 and 2009 was $6.6 million and $0.9 million. The aggregate intrinsic value at December 31, 2010, of phantom units expected to vest was $2.3 million.

16. Commitments and Contingencies

Rental Commitments

Operating lease rental expense in the years ended December 31, 2010, 2009 and 2008 was $9.6 million, $7.5 million and $4.5 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, 2010:

Year	Minimum Rental Commitments
2011	$ 4,094
2012	4,096
2013	4,052
2014	3,955
2015	3,898
Thereafter	7,341
Total minimum payments	$ 27,436

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 with regard to this subleased property cannot be estimated with certainty.

Firm Transportation Commitments

As of December 31, 2010, we had contracts for firm transportation capacity rights for specified volumes per day on a pipeline system with terms that ranged from one to five 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 sets forth our obligation for firm transportation commitments in effect at December 31, 2010 for the next five years and thereafter:

Year	Firm Transportation Commitments
2011	$ 12,628
2012	4,508
2013	4,033
2014	3,321
2015	1,661
Thereafter	-
Total firm transportation commitments	$ 26,151

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 or results of 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 on the relevant lessees for all environmental and reclamation liabilities arising under those laws and regulations. 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, 2010 and 2009, our environmental liabilities were $0.9 million and $1.0 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.

17. 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 periods presented:

	Year Ended December 31,		
	2010	2009	2008
Net income	$ 68,458	$ 65,215	$ 104,500
Unrealized holding losses on derivative activities	-	(506)	(4,039)
Reclassification adjustment for derivative activities	1,804	3,356	7,186
Comprehensive income	$ 70,262	$ 68,065	$ 107,647

Included in the accumulated other comprehensive income on the balance sheet at December 31, 2010 is $0.4 million of gains relating to Interest Rate Swaps on which we discontinued hedge accounting. The $0.4 million gain will be recognized in earnings through the end of 2011 as the hedged transactions settle. See Note 6, "Derivative Instruments."

18. Segment Information

Our operating segments represent components of our business 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 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* — Our coal and natural resource management segment primarily involves the management and leasing of coal properties and the subsequent collection of royalties. Our coal reserves are primarily located in Kentucky, Virginia, West Virginia, Illinois and New Mexico. We also earn revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage, fees.
- *Natural Gas Midstream* — Our natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. We own and operate natural gas midstream assets located in Oklahoma, Pennsylvania and 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.

The following table presents a summary of certain financial information relating to our segments as of and for the years ended December 31, 2010, 2009 and 2008:

	Revenues			Operating income		
	2010	2009	2008	2010	2009	2008
Coal and natural resource management(1)	$ 152,488	$ 144,600	$ 153,327	$ 93,132	$ 87,528	$ 96,296
Natural gas midstream(2)	711,648	512,104	728,253	32,767	20,774	18,946
Consolidated totals	$ 864,136	$ 656,704	$ 881,580	$ 125,899	$ 108,302	$ 115,242
Interest expense				(35,591)	(24,653)	(24,672)
Other				643	1,280	(2,907)
Derivatives				(22,493)	(19,714)	16,837
Consolidated net income				$ 68,458	$ 65,215	$ 104,500

	Additions to property and equipment			Depreciation, depletion & amortization		
	2010	2009	2008	2010	2009	2008
Coal and natural resource management	$ 25,751	$ 2,252	$ 27,270	$ 30,873	$ 31,330	$ 30,805
Natural gas midstream	98,365	78,425	304,758	45,027	38,905	27,361
Consolidated totals	$ 124,116	$ 80,677	$ 332,028	$ 75,900	$ 70,235	$ 58,166

	Total assets at December 31,		
	2010	2009	2008
Coal and natural resource management(3)	$ 585,559	$ 574,258	$ 600,418
Natural gas midstream(4)	711,942	633,802	618,402
Consolidated totals	$ 1,297,501	$ 1,208,060	$ 1,218,820

(1) Our coal and natural resource management segment's revenues for the years ended December 31, 2010, 2009 and 2008 include $2.0 million, $1.7 million and $1.8 million of equity earnings related to our 50% interest in Coal Handling Solutions LLC. See Note 8, "Equity Investments" for a further description.

(2) Our natural gas midstream segment's revenues for the years ended December 31, 2010, 2009 and 2008 include $6.0 million, $5.3 million and $2.4 million of equity earnings related to our 25% member interest in Thunder Creek that we acquired in 2008 for $51.6 million. See Note 3, "Acquisitions" for a further description of this acquisition and Note 8, "Equity Investments" for a further description of this segment's equity investment. Operating income for the year ended December 31, 2008 included a noncash impairment charge of $31.8 million related to the reduction in the value of natural gas midstream goodwill. See Note 9, "Goodwill" for further discussion of this impairment.

(3) Total assets at December 31, 2010, 2009 and 2008 for the coal and natural resource management segment included equity investment of $19.0 million, $21.0 million and $23.4 million related to our 50% interest in Coal Handling Solutions LLC. See Note 8, "Equity Investments" for a further description.

(4) Total assets at December 31, 2010, 2009 and 2008 for the natural gas midstream segment included equity investment of $58.8 million, $59.8 million and $55.0 million related to our 25% member interest in Thunder Creek that we acquired in 2008. Total assets for the year ended December 31, 2008 include the effects of the Lone Star acquisition. See Note 3, "Acquisitions" and Note 8, "Equity Investments" for a further description.

Operating income is equal to total revenues less cost of midstream gas purchased, operating costs and expenses and DD&A expense. Operating income does not include interest expense, certain other income items and derivatives. Identifiable assets are those assets used in our operations in each segment.

For the year ended December 31, 2010, two customers of our natural gas midstream segment accounted for $122.6 million and $97.0 million, or 14% and 11%, of our total consolidated net revenues. These customer concentrations may impact our results of operations, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We are not aware of any financial difficulties experienced by these customers.

For the year ended December 31, 2009, two of our natural gas midstream segment customers accounted for $109.5 million and $75.4 million, or 17% and 11%, of our total consolidated net revenues. For the year ended December 31, 2008, two customers of our natural gas midstream segment accounted for approximately $194.9 million and $93.8 million, or 22% and 11%, of our total consolidated net revenues.

Supplemental Quarterly Financial Information (Unaudited, in thousands except unit data)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2010				
Revenues	$ 206,478	$ 189,432	$ 222,829	$ 245,397
Operating income	$ 27,746	$ 24,876	$ 32,330	$ 40,947
Net income (loss)	$ 14,651	$ 23,260	$ 10,774	$ 19,773
Basic and diluted net income (loss) per limited partner unit, common and subordinated (1)	$ 0.16	$ 0.32	$ 0.09	$ 0.26
Weighted average number of units outstanding, basic and diluted	51,846	51,993	52,293	52,293
2009				
Revenues	$ 156,759	$ 149,419	$ 155,625	$ 194,901
Operating income	$ 21,927	$ 21,393	$ 27,816	$ 37,166
Net income (loss)	$ 9,468	$ 13,322	$ 18,824	$ 23,601
Basic and diluted net income (loss) per limited partner unit,common and subordinated (1)	$ 0.06	$ 0.13	$ 0.24	$ 0.33
Weighted average number of units outstanding, basic and diluted	51,799	51,799	51,799	51,799

(1) The sum of the quarters may not equal the total of the respective year's net income per limited partner unit due to applying the two-class method of calculating net income per limited partner unit.

19. Subsequent Event

In December, 2010, we announced a definitive agreement to purchase certain mineral rights and associated oil and gas royalty interest in Kentucky and Tennessee for approximately $97.3 million, subject to closing adjustments. The mineral rights include approximately 102.0 million tons of coal reserves and resources, and royalty interest from approximately 158 oil and gas wells. There are currently 14 active producing underground and surface mines on the approximately 126,000 acres of mineral estates being acquired, with 10 principal coal lessees operating the mines. The coal is primarily steam coal that is consumed by major electric utilities and other industrial customers in the southeastern United States. On January 25, 2011 we completed the purchase of these assets, which was funded by borrowings under our Revolver.

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, 2010. 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, 2010, 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, 2010. 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, 2010, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

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, 2010, which is included in Item 8 of this Annual Report on Form 10-K.

(d) 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

None.

PART III.

ITEM 10. Directors, Executive Officers and Corporate Governance

Information required to be set forth in Item 10. Directors, Executive Officers and Corporate Governance, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than April 30, 2011.

ITEM 11. Executive Compensation

Information required to be set forth in Item 11. Executive Compensation, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than April 30, 2011.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

Information required to be set forth in Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2010 Annual Meeting of Unitholders expected to be filed no later than April 30, 2011.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

Information required to be set forth in Item 13. Certain Relationships and Related Transactions, and Director Independence, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than April 30, 2011.

ITEM 14. Principal Accountant Fees and Services

Information required to be set forth in Item 14. Principal Accountant Fees and Services, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than April 30, 2011.

Part IV

Item 15 Exhibits and 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 71 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 June 17, 2008 between Lone Star Gathering, L.P. and Penn Virginia Resource Partners, L.P., as amended by First Amendment to Purchase and Sale Agreement dated as of July 17, 2008 (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on July 22, 2008).
(2.2)	Agreement and Plan of Merger, dated September 21, 2010, by and among Penn Virginia Resource Partners, L.P., Penn Virginia Resource GP, LLC, PVR Radnor, LLC, Penn Virginia GP Holdings, L.P. and PVG GP, LLC (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on September 22, 2010).
(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)	Third 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 August 7, 2008).
(3.2.1)	Amendment No. 1 to Third 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 February 24, 2009).
(3.2.2)	Amendment No. 2 to Third 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 March 31, 2010).
(3.3)	Limited Liability Company Agreement of PVR Finco LLC (incorporated by reference to Exhibit 3.2 to Registrant's Current Report on Form 8-K filed on August 7, 2008).
(3.4)	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).
(3.5)	Fifth 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 March 31, 2010).
(10.1)	Amended and Restated Credit Agreement, dated as of August 13, 2010 by and among PVR Finco LLC, the guarantors party thereto, PNC Bank, National Association, as Administrative 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 August 19, 2010).
(10.2)	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).
(10.3)	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).
(10.4)	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).
(10.5)	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).
(10.6)	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).

(10.7)	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).
(10.8)	Units Purchase Agreement dated June 17, 2008 by and among Penn Virginia Resource LP Corp., Kanawha Rail Corp. and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on July 22, 2008).
(10.9)	Penn Virginia Resource GP, LLC Fifth 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 January 15, 2009).*
(10.10)	Form of Agreement for Deferred Common Unit Grants under the Penn Virginia Resource GP, LLC Fifth Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.14 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.11)	Form of Agreement for Restricted Unit Awards under the Penn Virginia Resource GP, LLC Fifth Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.15 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.12)	Form of Agreement for Phantom Unit Awards under the Penn Virginia Resource GP, LLC Fifth 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 February 24, 2009).*
(10.13)	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).*
(10.14)	Amended and Restated Executive Change of Control Severance Agreement dated October 17, 2008 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 October 22, 2008).*
(10.15)	Amended and Restated Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Resource GP, LLC and Ronald K. Page (incorporated by reference to Exhibit 10.15 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2008).*
(10.16)	Employment Agreement between Robert B. Wallace and Penn Virginia Resource GP, LLC dated March 23, 2010 (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 24, 2010).*
(10.17)	Amended and Restated Employment Agreement between William H. Shea, Jr. and Penn Virginia Resource GP, LLC dated March 23, 2010 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on March 24, 2010).*
(10.18)	Asset Purchase and Sale Agreement by and between Penn Virginia Operating Company, LLC and Begley Properties, LLC dated December 15, 2010 (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 15, 2010).
(10.19)	Penn Virginia Resource GP, LLC Non-Employee Director Compensatory Summary Sheet for 2011. *
(10.20)	Memorandum of Understanding, dated February 1, 2011, among Penn Virginia Resource Partners, L.P., Penn Virginia Resource GP, LLC, PVR Radnor LLC, Penn Virginia GP Holdings, L.P., PVG GP, LLC the individual directors of Holdings GP, and Kevin Epoch, Sanjay Israni and Anita Scheifele (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on February 7, 2011).
(12.1)	Statement of Computation of Ratio of Earnings to Fixed Charges Calculation.
(14.1)	Penn Virginia Resource GP, LLC Code of Business Conduct and Ethics (incorporated by reference to Exhibit 14.1 to Registrant's Current Report on Form 8-K filed on July 24, 2009).
(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

	By:
February 24, 2011	/s/ Robert B. Wallace Robert B. Wallace Executive Vice President and Chief Financial Officer
	By:
February 24, 2011	/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 or on behalf of the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ William H. Shea, Jr. William H. Shea	Director and Chief Executive Officer	February 24, 201
/s/ Edward B. Cloues, II Edward B. Cloues, II	Director	February 24, 201
/s/ James L. Gardner James L. Gardner	Director	February 24, 201
/s/ Thomas W. Hofmann Thomas W. Hofmann	Director	February 24, 201
/s/ James R. Montague James R. Montague	Director	February 24, 201
/s/ Marsha R. Perelman Marsha R. Perelman	Director	February 24, 201

Exhibit 10.19

Penn Virginia Resource GP, LLC
Non-Employee Director Compensation Summary Sheet for 2011

Directors who are employees of Penn Virginia Resource GP, LLC or its affiliates receive no additional compensation for service on the general partner's board of directors or any committees of the board. The table below summarizes the 2011 compensation program for the non-employee directors of Penn Virginia Resource GP, LLC.

2011 Non-Employee Director Compensation Summary

Component	Amount ($)	Medium of Payment (1)	Timing of Payment (2)
Annual Retainer	90,000 per year	Deferred Common Units	$22,500 credited quarterly
	20,000 per year	Cash	$5,000 paid quarterly
Audit Committee Chair Annual Retainer	15,000 per year	Cash	$3,750 paid quarterly
Audit Committee Member Annual Retainer	10,000 per year	Cash	$2,500 paid quarterly
Compensation and Benefits and Conflicts Chair Annual Retainer	2,500 per year	Cash	$625 paid quarterly
Board Meeting Fee	1,000 per meeting	Cash	Paid quarterly
Committee Meeting Fee	1,000 per meeting	Cash	Paid quarterly

(1) Each non-employee director receives an annual retainer of $110,000, consisting of $20,000 in cash and $90,000 worth of deferred common units, which are credited to each director's Deferred Compensation Account. In addition, directors may elect to receive any cash payments in common units or deferred common units, and may elect to defer the receipt of cash or common units they receive under the Penn Virginia Resource GP, LLC Amended and Restated Non-Employee Directors Deferred Compensation Plan.

(2) The fair market value of each quarterly crediting of deferred common units is based upon the NYSE closing price of our common units on the dates that such awards are granted.

Exhibit 12.1

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

	Year Ended December 31,				
	2006	2007	2008	2009	2010
Earnings					
Pre-tax income *	$ 74,910	$ 55,552	$ 103,603	$ 62,452	$ 71,341
Fixed charges	19,783	19,766	26,850	27,368	39,164
Total earnings	**$ 94,693**	**$ 75,318**	**$ 130,453**	**$ 89,820**	**$ 110,505**
Fixed Charges					
Interest expense	$ 19,151	$ 18,896	$ 25,346	$ 24,878	$ 35,982
Rental interest factor	632	870	1,504	2,490	3,182
Total fixed charges	**$ 19,783**	**$ 19,766**	**$ 26,850**	**$ 27,368**	**$ 39,164**
Ratio of earnings to fixed charges	**4.8x**	**3.8x**	**4.9x**	**3.3x**	**2.8x**

* Includes cash distributions from equity affiliates and excludes equity earnings from affiliates. Also excludes capitalized interest.

Exhibit 21.1

Subsidiaries of Penn Virginia Resource Partners, L.P.

Name	Jurisdiction of Organization
Penn Virginia Resource Finance Corporation	Delaware
Penn Virginia Operating Co., LLC	Delaware
Fieldcrest Resources LLC	Delaware
K Rail LLC	Delaware
Loadout LLC	Delaware
Toney Fork LLC	Delaware
Suncrest Resources LLC	Delaware
Coal Handling Solutions LLC	Delaware
Kingsport Handling LLC	Delaware
Maysville Handling LLC	Delaware
Covington Handling LLC	Delaware
PVR Midstream LLC	Delaware
PVR Gas Resources, LLC	Delaware
Connect Energy Services, LLC	Delaware
Connect Gas Pipeline LLC	Delaware
PVR North Texas Gas Gathering, LLC	Delaware
Dulcet Acquisition LLC	Delaware
Thunder Creek Gas Services, L.L.C. (25% Joint Venture)	Wyoming
PVR Cherokee Gas Processing LLC	Oklahoma
PVR East Texas Gas Processing, LLC	Delaware
PVR Finco LLC	Delaware
PVR Gas Processing LLC	Oklahoma
PVR Hamlin, LLC	Delaware
PVR Natural Gas Gathering LLC	Oklahoma
PVR Oklahoma Natural Gas Gathering LLC	Oklahoma
PVR Radnor, LLC	Delaware
PVR Marcellus Gas Gathering, LLC	Delaware
LJL, LLC	West Virginia

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We consent to the incorporation by reference in the registration statements on Form S-8 (Nos. 333-74212 and 333-156732), on Form S-3 (No. 333-162118) and on Form S-4 (No. 333-170102) of Penn Virginia Resource Partners, L.P. and subsidiaries (the Partnership) of our reports dated February 24, 2011, with respect to the consolidated balance sheets of the Partnership as of December 31, 2010 and 2009, 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, 2010, and the effectiveness of internal control over financial reporting as of December 31, 2010, which reports appear in the December 31, 2010 Annual Report on Form 10-K of the Partnership.

/s/ KPMG LLP

Houston, Texas
February 24, 2011

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, William H. Shea, Jr., 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 24, 2011

/s/ William H. Shea, Jr.

William H. Shea, Jr.
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, Robert B. Wallace, Executive 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:
   e) 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 24, 2011

/s/ Robert B. Wallace

Robert B. Wallace
Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Penn Virginia Resource Partners, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William H. Shea, Jr., 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 24, 2011

/s/ William H. Shea, Jr.

William H. Shea, Jr.
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, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert B. Wallace, Executive 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 24, 2011

/s/ Robert B. Wallace

Robert B. Wallace
Executive Vice President and Chief Financial Officer

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

PARTNERSHIP INFORMATION

DIRECTORS*

Edward B. Cloues, II[2]

James L. Gardner[1,2,3]

Robert J. Hall[4]

Thomas W. Hofmann[1,2,3]

James R. Montague[1,2,3]

Marsha R. Perelman

William H. Shea, Jr.

John C. van Roden, Jr.[4]

Jonathan B. Weller[4]

1 Member of Audit Committee

2 Member of Compensation & Benefits Committee

3 Member of Conflicts Committee

4 Appointed effective 3/10/2011 following merger with PVG

** Directors of our general partner, Penn Virginia Resource GP, LLC*

MANAGEMENT

William H. Shea, Jr.
Chief Executive Officer

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

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

Robert B. Wallace
Executive Vice President and
Chief Financial Officer

Bruce D. Davis, Jr.
Executive Vice President,
General Counsel and Secretary

Forrest W. McNair
Vice President and Controller

Robert J. Proffit
Vice President, Human Resources

PARTNERSHIP CHARACTERISTICS

As a publicly traded partnership, Penn Virginia Resource Partners, L.P. ("PVR") differs in several respects from stock corporations:

- A partner in a publicly traded partnership owns units of the partnership rather than shares of stock and receives cash distributions rather than dividends. The cash distributions are treated as return of capital as long as the partner's tax basis in the partnership is positive.

- Generally, a corporation is subject to federal and state income taxes but a partnership is not. All of the income, gains, losses and deductions of a partnership are passed through to its partners, who are required to report their allocated share of these amounts on their personal income tax returns.

- While an owner of corporate stock receives a Form 1099 each year detailing required tax data, an owner of a partnership unit receives a tax reporting package including Schedule K-1 and other forms to file with their income tax return. This tax reporting package shows a partner's allocable share of the partnership's income, gains, losses and deductions.

- Compared to the corporate form of organization, the partnership form enables PVR to distribute to investors a greater percentage of cash generated by the business.

Investor Information

For more information about PVR, please contact:

Stephen R. Milbourne
Director, Investor Relations

610-975-8204
invest@pvrpartners.com
or visit our website:
www.pvrpartners.com

Partnership Office

Penn Virginia Resource Partners, L.P.
Five Radnor Corporate Center, Suite 500
100 Matsonford Road
Radnor, PA 19087

610-975-8200 *phone*
610-975-8201 *fax*

Transfer Agent & Registrar

American Stock Transfer
& Trust Company, LLC

59 Maiden Lane
New York, NY 10038

877-248-6417 *phone*
718-236-2641 *fax*

Unitholder Tax Information

PricewaterhouseCoopers, LLP
K-1 Support
P.O. Box 799060,
Dallas, TX 75379

877-699-1092 *phone*
866-544-3842 *fax*

Equal Opportunity

Penn Virginia Resource Partners, L.P. provides equal opportunity in all aspects of employment without regard to race, color, creed, religion, ancestry, national origin, gender, age, disability, veteran or marital status.

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