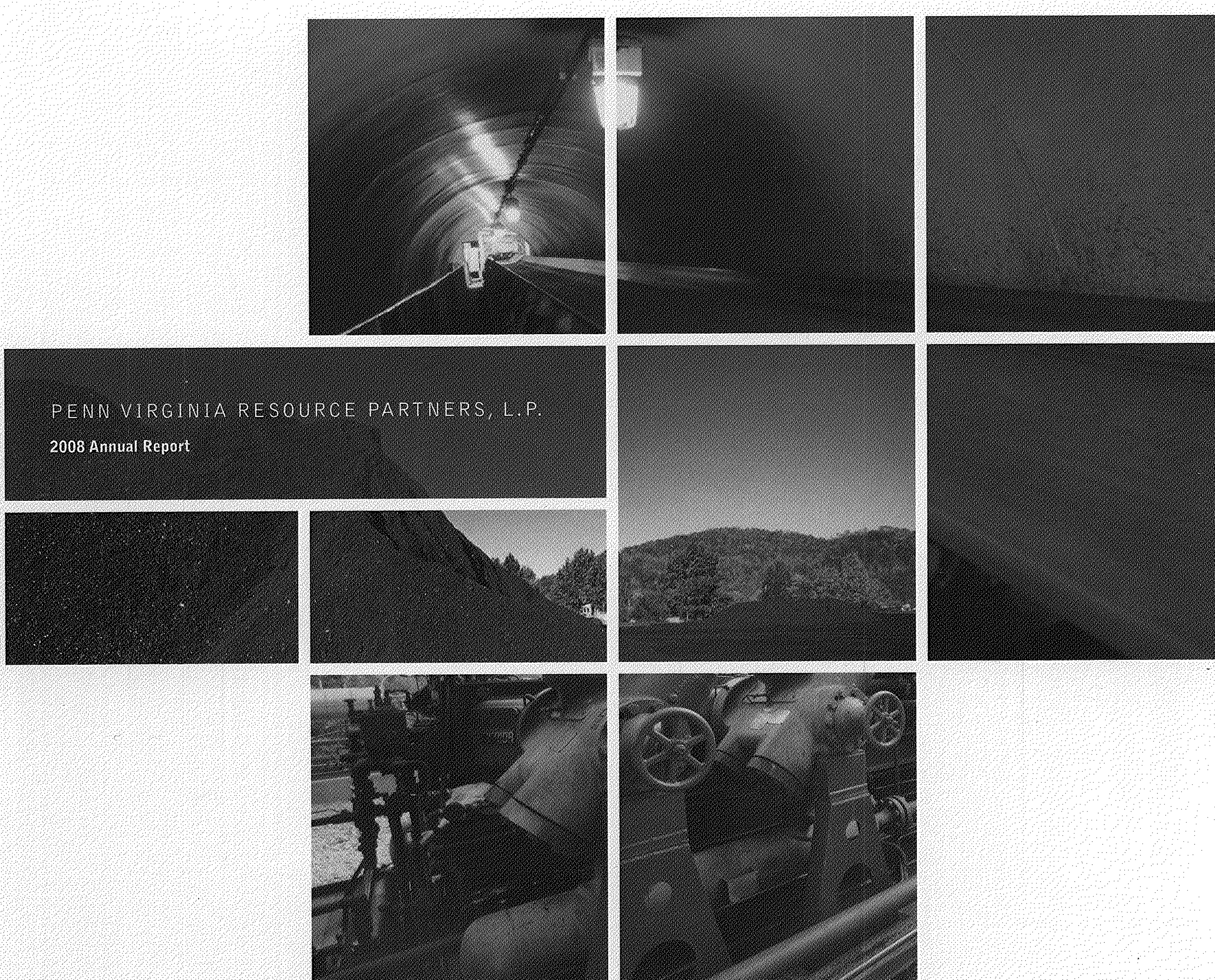
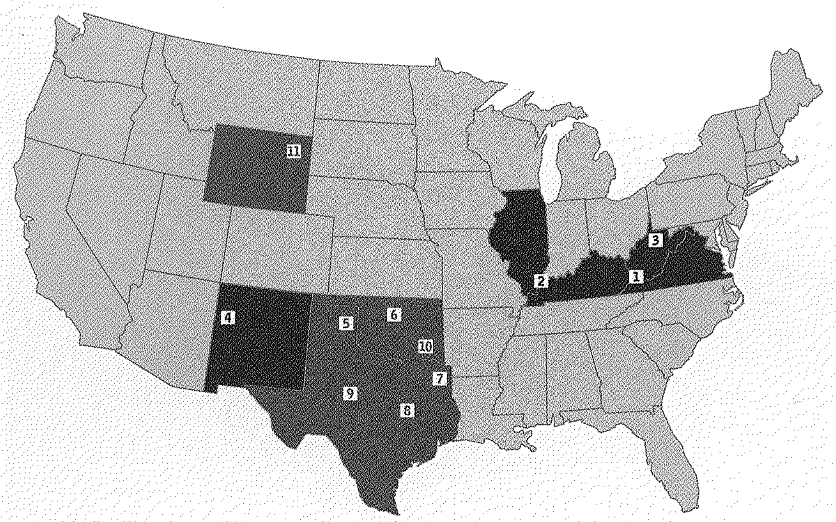


PENN VIRGINIA RESOURCE PARTNERS, L.P.

2008 Annual Report

PVR'S COAL AND NATURAL RESOURCE MANAGEMENT & MIDSTREAM LOCATIONS



1. Central Appalachia
Coal reserves and infrastructure, timber, oil and gas royalties

2. Illinois Basin
Coal reserves and infrastructure

3. Northern Appalachia
Coal reserves

4. San Juan Basin
Coal reserves

5. Panhandle
Gas processing plants and gathering systems

6. Crescent
Gas processing plant and gathering systems

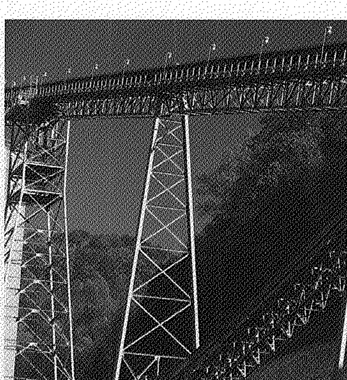
7. Crossroads
Gas processing plant and gathering system

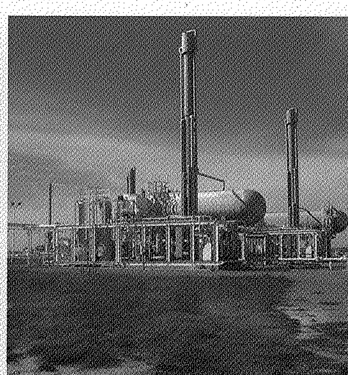
8. North Texas Gas Gathering
Gas gathering and pipeline systems

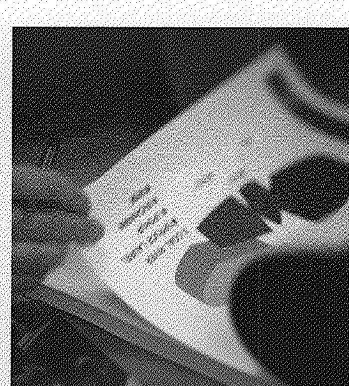
9. Hamlin
Gas processing plant and gathering system

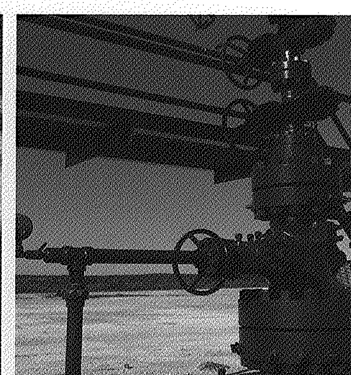
10. Arkoma
Gas gathering systems

11. Thunder Creek
Gas gathering and pipeline systems









COAL AND NATURAL RESOURCE MANAGEMENT

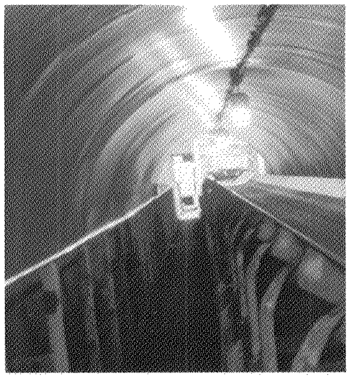
PVR Coal and Natural Resource Management oversees our coal and natural resource properties, provides fee-based coal preparation and loading services, sells timber, collects oil and gas royalties, and collects wheelage fees from the transportation of coal. In recent years, PVR acquired coal reserves in multiple basins, expanded its coal services and infrastructure business and has added other PTP-friendly natural resource assets, such as timber and natural gas royalties.

NATURAL GAS MIDSTREAM

PVR Midstream provides natural gas processing, gathering and other related services at seven primary locations in Texas, Oklahoma and Wyoming. PVR Midstream has experienced strong growth in system throughput volumes since its inception over three years ago, via acquisitions as well as organic growth, which includes the expansion of existing systems via new well connections and processing plants. PVR Midstream's cash flow is derived primarily from both market-sensitive and, increasingly, fee-based services.

FINANCIAL DISCIPLINE

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



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

FINANCIAL HIGHLIGHTS

In millions except per share data	2008	2007	2006	2005	2004
Financial Data					
Net revenues[1]	**$ 269.1**	$ 206.2	$ 183.3	$ 142.4	$ 75.6
Operating income	**115.2**	117.7	102.8	78.1	40.5
Net income	**104.5**	56.6	73.9	51.2	34.3
Cash flow from operations	**139.2**	127.8	107.3	93.7	54.8
Distributable cash flow[2]	**129.9**	120.5	101.6	86.7	53.4
Total assets	**1,218.8**	931.3	714.0	657.9	284.4
Long-term debt, excluding current portion	**568.1**	399.2	207.2	246.8	112.9
Partners' capital	**530.7**	371.3	402.2	284.0	150.0
Long-term debt as percent of total capitalization	**52%**	52%	34%	46%	43%
Per Limited Partner Unit Data[3]					
Net income[4]	**$ 1.67**	$ 0.96	$ 1.56	$ 1.22	$ 0.93
Cash distributions declared[5]	**1.88**	1.72	1.60	1.30	1.08
Weighted average number of limited partner units outstanding	**51.8**	46.1	42.0	40.3	36.1
Operating Data					
Coal produced by lessees (millions of tons)	**33.7**	32.5	32.8	30.2	31.2
Coal royalties ($/ton)	**$ 3.65**	$ 2.89	$ 2.99	$ 2.74	$ 2.23
Estimated coal reserves (millions of recoverable tons)	**827**	818	765	689	558
Natural gas system volumes (MMcfd)	**270**	186	170	144	—

(1) 2005-2008 amounts are shown net of cost of gas purchased of $613 million, $343 million, $335 million and $304 million, respectively.

(2) Distributable cash flow is calculated as follows:

	2008	2007	2006	2005	2004
Net income	**$ 104.5**	$ 56.6	$ 73.9	$ 51.2	$ 34.3
Depreciation, depletion and amortization	**58.2**	41.5	37.5	30.6	18.6
Goodwill impairment	**31.8**	—	—	—	—
Derivative losses (gains)	**5.5**	4.6	2.0	(1.0)	—
Cash paid to settle derivatives	**(38.5)**	(17.8)	(19.4)	(4.8)	—
Equity earnings from joint ventures	**(4.2)**	(1.8)	(1.3)	(1.0)	(0.4)
Cash distributions from joint ventures	**4.0**	1.5	2.6	2.3	1.0
Maintenance capital expenditures	**(14.5)**	(9.8)	(9.5)	(4.6)	(0.1)
Other	**—**	—	4.5	—	—
Distributable cash flow	**$ 129.9**	$ 120.5	$ 101.6	$ 86.7	$ 53.4

(3) Per unit data reflects 2-for-1 unit split in April 2006.

(4) Per unit amount is computed after general partner's share.

(5) Annualized as of last quarterly distribution paid in year.

A. JAMES DEARLOVE
Chairman and Chief Executive Officer

2008 KEY EVENTS

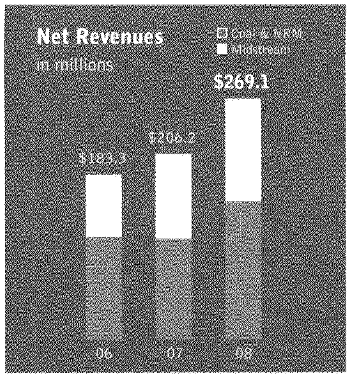
- Record net revenues, distributable cash flow and net income during 2008
- Record lessee coal production during 2008 and record natural gas midstream system throughput volumes during 2008
- Approximately $319 million spent for midstream acquisitions and expansions, adding 140 million cubic feet per day (MMcfd) of processing capacity and approximately 400 miles of pipeline
- Added 29 million tons of coal reserves and timber in a $25 million Central Appalachia acquisition
- Increased cash distributions on three occasions during the year, increasing nine percent over 2007
- Completed a public offering of common units and upsized the revolving credit facility on favorable terms

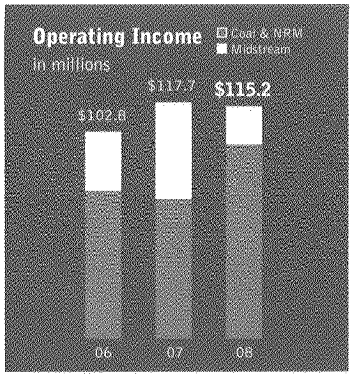
DEAR FELLOW UNITHOLDERS,

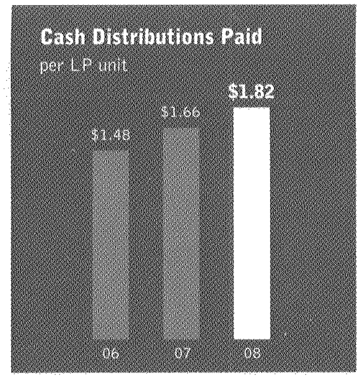
We are pleased to report that 2008 was another record year for Penn Virginia Resource Partners, L.P. (PVR) including record levels of net revenues, net income and distributable cash flow. We also enjoyed record-setting operational results including coal production by our lessees and system throughput volumes in our natural gas midstream business. We increased distributions to unitholders three times during 2008, with total distributions up nine percent over 2007.

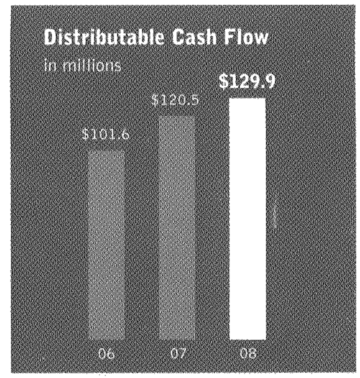
Despite this success, energy industry fundamentals began to erode by the fourth quarter of 2008 due to the onset of a severe recession that is expected to weigh upon industry activity levels and results in 2009 and perhaps beyond. We believe that our coal royalty business, which provides the majority of our cash flow, will be stable in 2009 due in large part to the long-term contracts our lessees have with their customers. However, it will be a challenge for PVR Midstream to repeat its 2008 performance as processing margins have narrowed considerably from record levels. Ultimately, we expect stability to return to the energy industry and a rebound in processing margins.

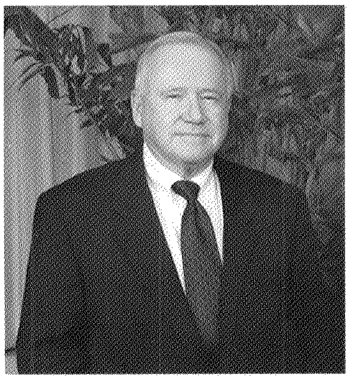
In our Coal and Natural Resource Management (NRM) segment, coal reserves increased to 827 million tons as of year-end 2008 from 818 million tons at year-end 2007. We replaced 125 percent of the 33.7 million tons of reserves produced by lessees during 2008. During 2008, PVR completed the acquisition of approximately 29 million









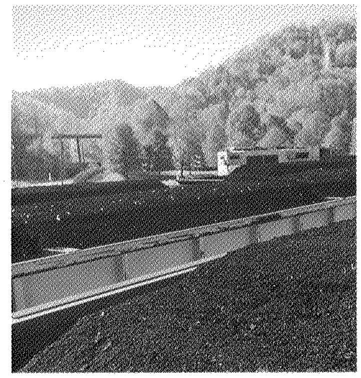


In Memoriam

JOHN P. DESBARRES

1939 - 2008

PVR Director since 2001



tons of coal reserves along with an estimated 56 million board feet of hardwood timber in Central Appalachia for $24.5 million. Approximately 70 percent of our reserve base is in Central Appalachia and 20 percent is in the Illinois Basin. We remain confident in the future of coal as our nation's primary power fuel and subject to financial and capital market and regulatory conditions, we continue to review acquisition opportunities in these core regions.

Coal prices increased to record levels in early 2008, peaking by the third quarter, as overseas supply issues, a weaker U.S. dollar and strong global demand fueled growth in exports. Domestic demand was also strong during much of 2008, as power consumption grew and the costs of competing fuels remained high. Natural gas prices also stayed high for much of the year, relative to coal, largely as the result of record oil prices and increased demand. However, by the fourth quarter, demand for energy declined markedly as the U.S. economy entered a severe recession. Prior to this decline, our lessees were able to renegotiate long-term contracts with their customers and over 80 percent of market-sensitive volumes in 2009 will be covered by these favorably-priced contracts.

During 2008, PVR Midstream's system throughput volumes increased 46 percent and its gross processing margin increased 20 percent over 2007. PVR completed $259.4 million of midstream acquisitions and spent $59.4 million for expansion, primarily two processing plants in Texas with a combined processing capacity of 140 MMcf per day.

The growth in system throughput volumes was attributable to the acquisitions and expansions we made in 2008, as well as increased natural gas production from existing fields we service. In addition, the processing margin increase was due to record fractionation or "frac" spreads during the first half of 2008, although these frac spreads decreased substantially by the end of the year. As we head into 2009, the impact of lower frac spreads is expected to be offset by expected increased volumes due to the acquisitions and expansions, as well as improved settlements from favorable 2009 hedging contracts we put into place during the height of the market in 2008. We expect that improvements in frac spreads may take longer than historical recovery periods due to weakness in the general economy and excess supply of natural gas liquids (NGLs) due to the economy and lingering effects of hurricane-related supply disruptions during the second half of 2008. As is the case with Coal and Natural Resource Management, we remain confident in the future of the midstream business and subject to financial and capital market and regulatory conditions, will continue to review acquisition opportunities.

On a sad note, we unexpectedly lost a good friend, colleague and outside director with the passing of John DesBarres in December 2008. John was a great source of wisdom and counsel and he will be missed greatly both personally and professionally.

The energy industry is a cyclical business and during peaks, such as early in 2008, and troughs, which we have been facing since late 2008. We will manage our businesses to best position ourselves for continued growth once fundamentals strengthen. As always, we greatly appreciate the hard work and dedication of our employees and the continued loyalty and support of our unitholders.

James Dearlove

A. JAMES DEARLOVE
Chairman and Chief Executive Officer

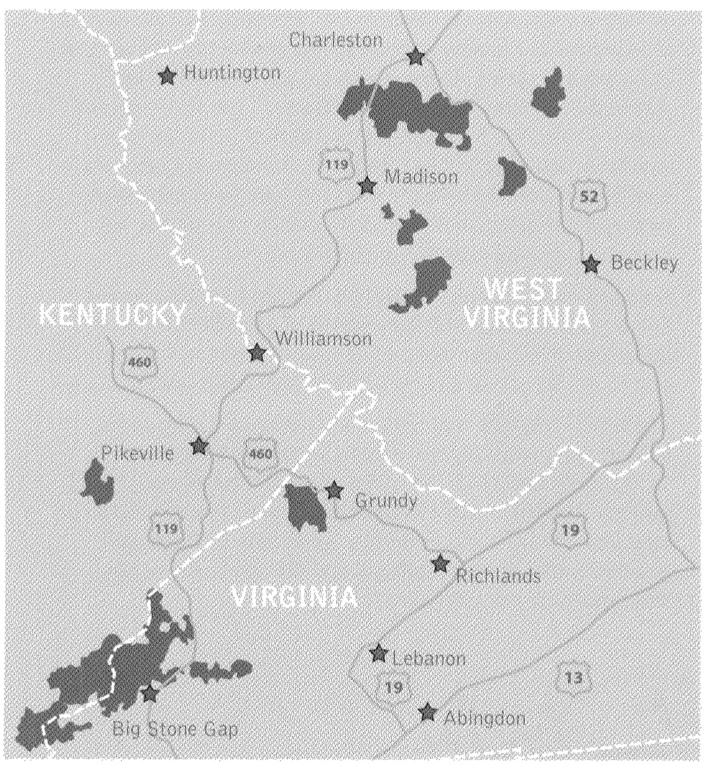
COAL AND NATURAL RESOURCE MANAGEMENT

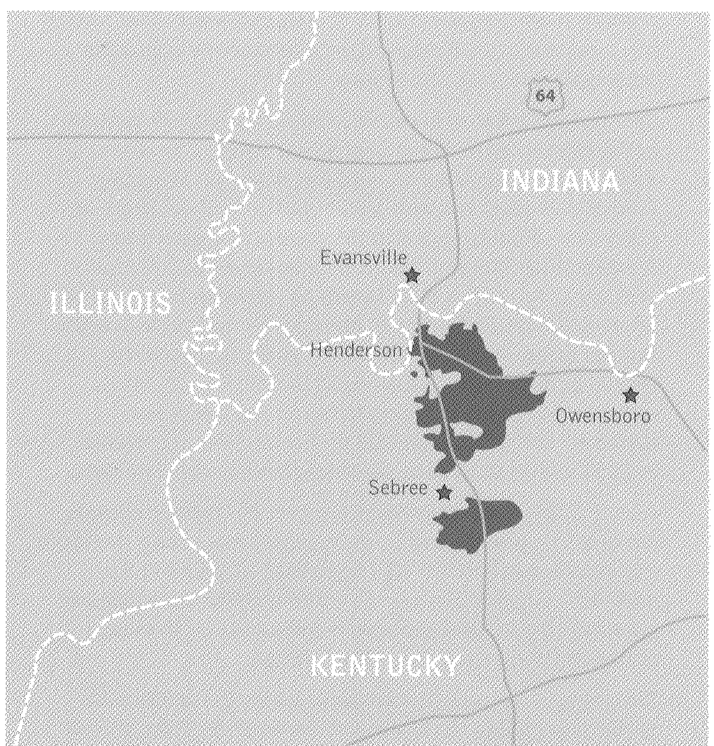
CENTRAL APPALACHIA

Properties located in eastern Kentucky, southwestern Virginia and southern West Virginia with approximately 590 million tons, or 71 percent, of our reserves. The reserves are predominantly low to medium sulfur, high-BTU content steam coal. Approximately 19.6 million tons, or 58 percent, of lessee production in 2008 was in this region at an average royalty rate of $4.78 per ton.

ILLINOIS BASIN

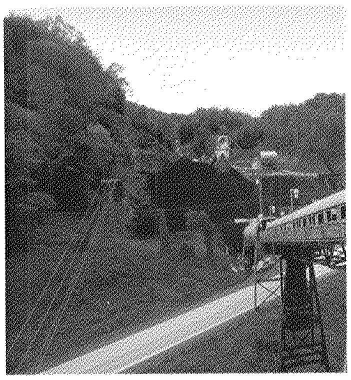
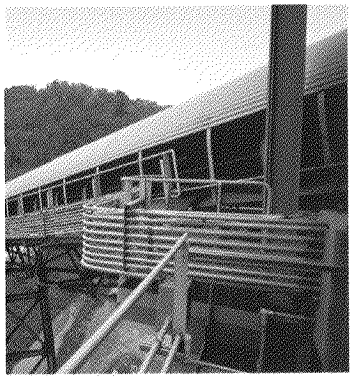
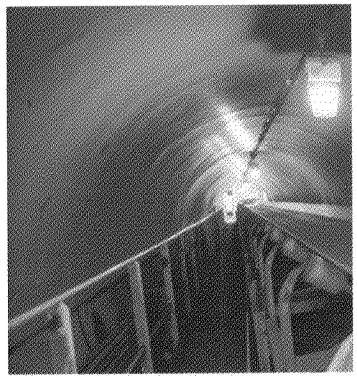
Properties located in western Kentucky and southern Illinois with approximately 166 million tons, or 20 percent, of our reserves. The reserves consist of high sulfur, medium-BTU content steam coal located on three properties. Approximately 4.6 million tons, or 14 percent, of lessee production in 2008 was in this region at an average royalty rate of $2.28 per ton.





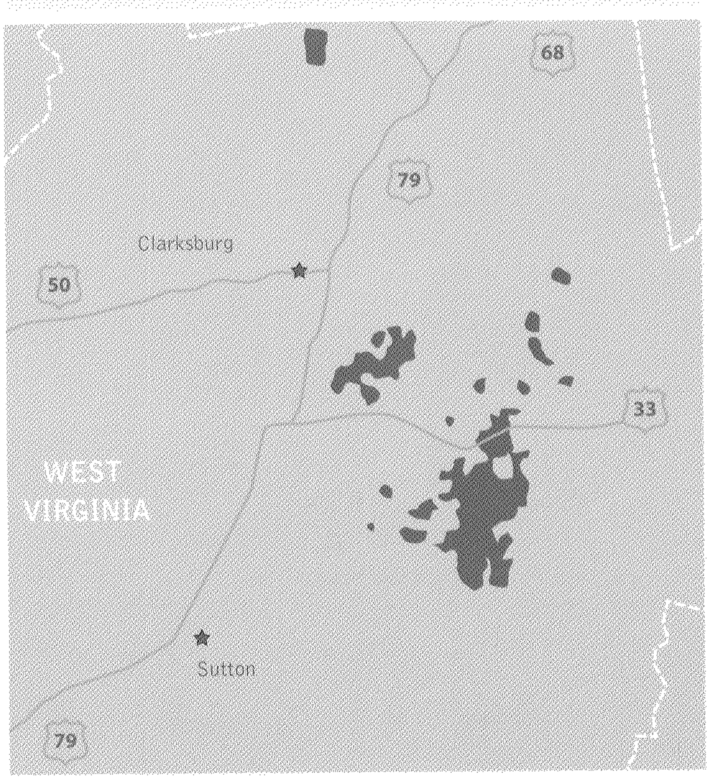
590 MILLION
TONS OF COAL RESERVES

166 MILLION
TONS OF COAL RESERVES


NORTHERN APPALACHIA

Properties located in northern West Virginia with approximately 26 million tons, or three percent, of our reserves. The underground reserves consist of high sulfur, high-BTU content steam coal located on two properties. Approximately 3.6 million tons, or 11 percent, of lessee production in 2008 was in this region at an average royalty rate of $1.84 per ton.



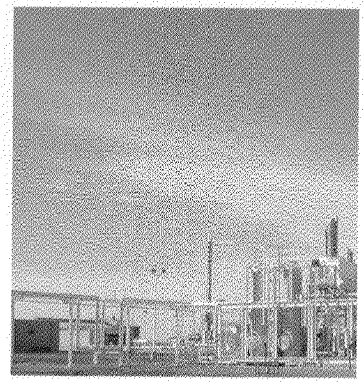
26 MILLION
TONS OF COAL RESERVES

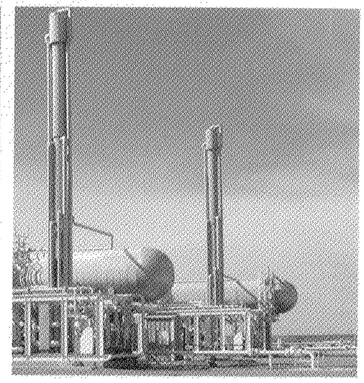
SAN JUAN BASIN

Properties located in northwestern New Mexico with approximately 45 million tons, or five percent, of our reserves. The surface reserves are predominantly low to medium sulfur, low-BTU content steam coal. Approximately 5.9 million tons, or 18 percent, of lessee production in 2008 was in this region at an average royalty rate of $2.06 per ton.

45 MILLION
TONS OF COAL RESERVES

MIDSTREAM



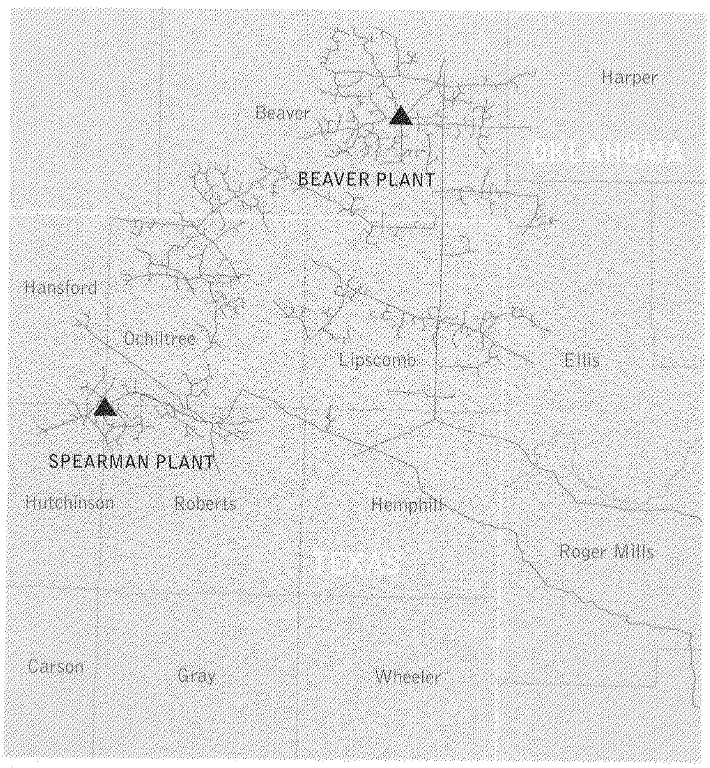


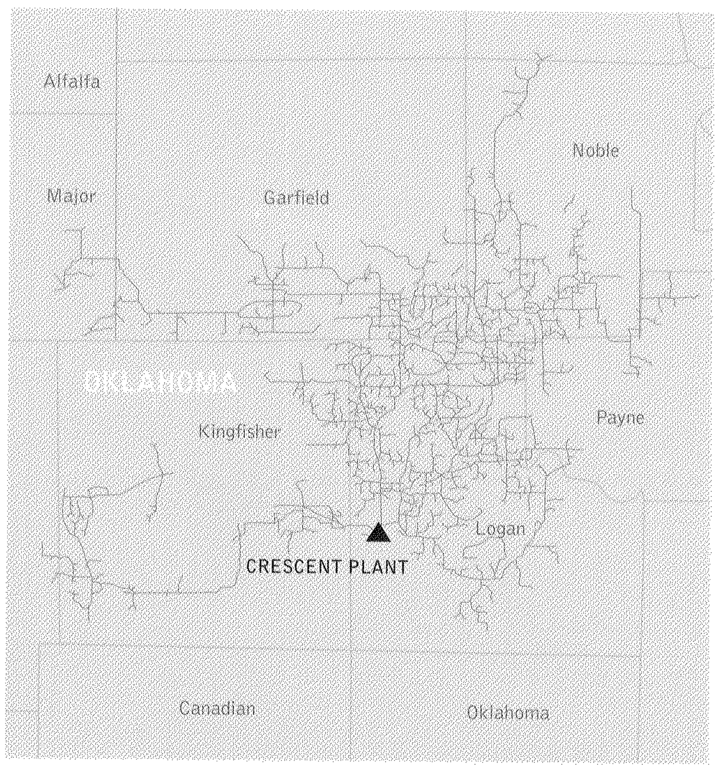
PANHANDLE

The Panhandle System, located in the panhandle of Texas and western Oklahoma, consisted of 1,648 miles of gathering pipelines, 160 MMcfd of gas processing capacity at two plants (100 MMcfd at Beaver and 60 MMcfd at Spearman) and had approximately 1,000 wells connected as of year-end 2008. During 2008, average system throughput volume was approximately 181 MMcfd, or 67 percent of total volumes, with an average gas processing utilization rate of 100%.

CRESCENT

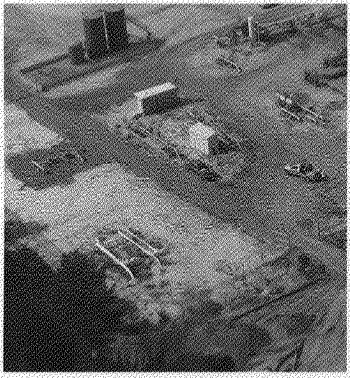
The Crescent System, located in north central Oklahoma, consisted of 1,698 miles of gathering pipelines, a 40 MMcfd capacity gas processing plant and had approximately 850 wells connected as of year-end 2008. During 2008, average system throughput volume was approximately 23 MMcfd, or eight percent of total volumes, with an average gas processing utilization rate of 56%.

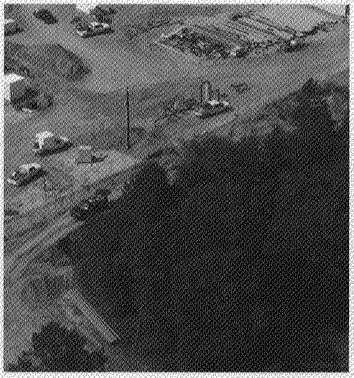


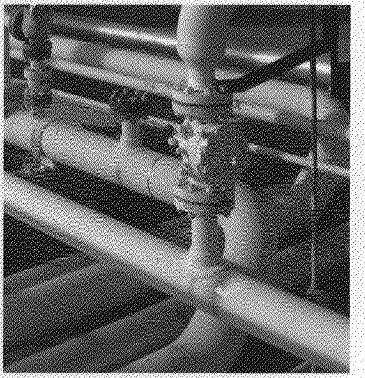


181 MMcfd
2008 SYSTEM THROUGHPUT VOLUME

23 MMcfd
2008 SYSTEM THROUGHPUT VOLUME





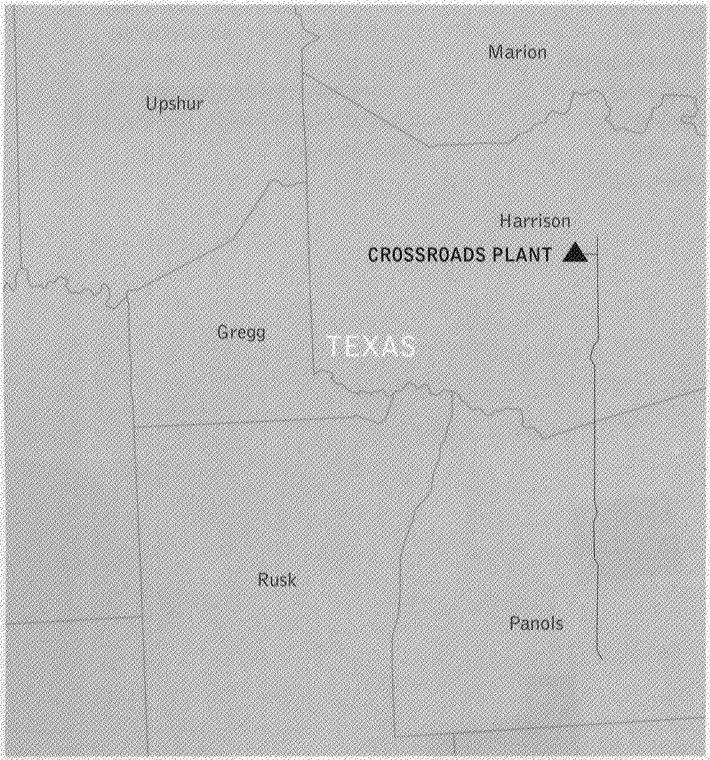


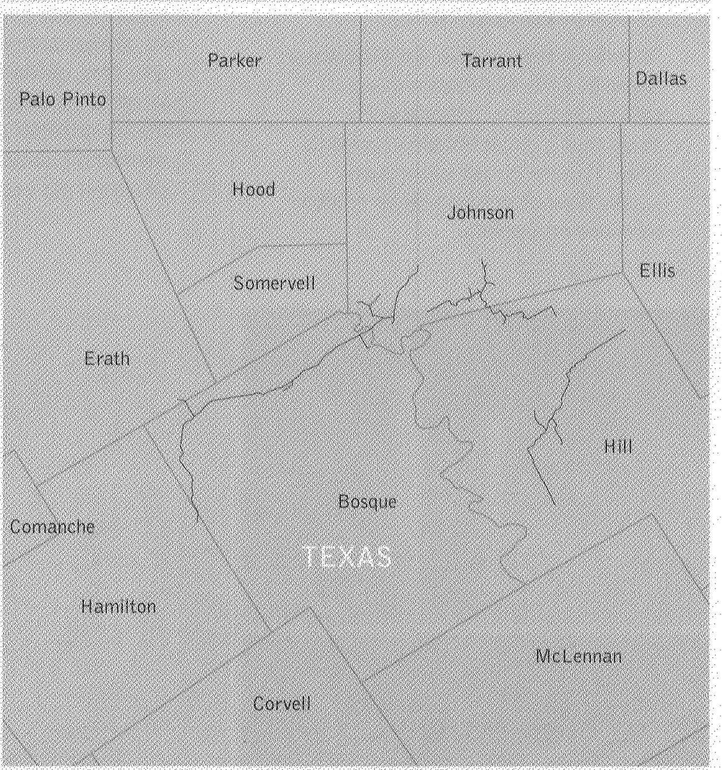
CROSSROADS

The Crossroads System, located in east Texas, consisted of eight miles of gathering pipelines and an 80 MMcfd capacity gas processing plant as of year-end 2008. During 2008, average system throughput volume was approximately 36 MMcfd, or 13 percent of total volumes, with an average gas processing utilization rate of 45%.

NORTH TEXAS GAS GATHERING (NTGG)

The North Texas Gas Gathering System, located in the Fort Worth Basin of north Texas, consisted of 131 miles of gathering pipelines and had approximately 39 wells connected as of year-end 2008. During 2008, average system throughput volume was approximately 10 MMcfd, or four percent of total volumes. The system was acquired in July 2008 and provides gathering and transportation services to the southern end of the Barnett Shale play.





36 MMcfd
2008 SYSTEM THROUGHPUT VOLUME

131 MILES
GATHERING PIPELINES

2008 MIDSTREAM ACQUISITIONS

1 THUNDER CREEK JOINT VENTURE

In April 2008, PVR Midstream acquired a 25 percent member interest in Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin, for $51.6 million in cash.

Thunder Creek is an independently operated joint venture that is one of the major coalbed methane gatherers in Wyoming's Powder River Basin. Thunder Creek's primary assets consist of a 355-mile high-pressure gathering system with a capacity of 450 MMcfd, five low-pressure gathering systems with 194 miles of pipeline, a 210 MMcfd CO_2 treating facility and approximately 65,000 horsepower of compression. All of the revenue for Thunder Creek is from gathering, transportation, treating and compression fees, with no commodity price exposure.

Thunder Creek expands the geographic scope of PVR Midstream into a prolific, resource-rich producing basin that is expected to continue to grow. Thunder Creek has a stable supply base of predominantly coalbed methane production.

2 PANHANDLE SYSTEM ACQUISITION

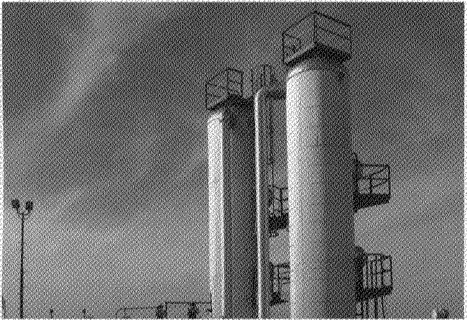
In July 2008, PVR Midstream acquired pipeline assets in the Anadarko Basin for $29.7 million in cash. The acquired assets consisted of 100 miles of 10-inch and 12-inch diameter pipelines and approximately 5,000 horsepower of compression and are located in the Anadarko Basin in Roger Mills County, Oklahoma, and in Hemphill, Ochiltree and Roberts Counties, Texas.

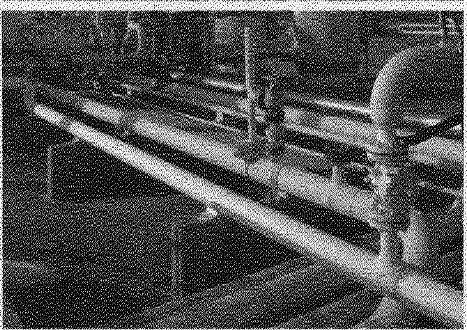
The acquired pipelines expanded PVR Midstream's gathering footprint, providing access to additional sources of natural gas production. Prior to the acquisition, PVR Midstream had gas volumes on its gathering systems that it could not process due to capacity constraints at its Beaver plant. This acquisition allowed certain previously non-contiguous pipeline and gathering systems to be connected, giving PVR Midstream the option of moving volumes directly to either its Beaver gas processing plant or its new Spearman gas processing plant.

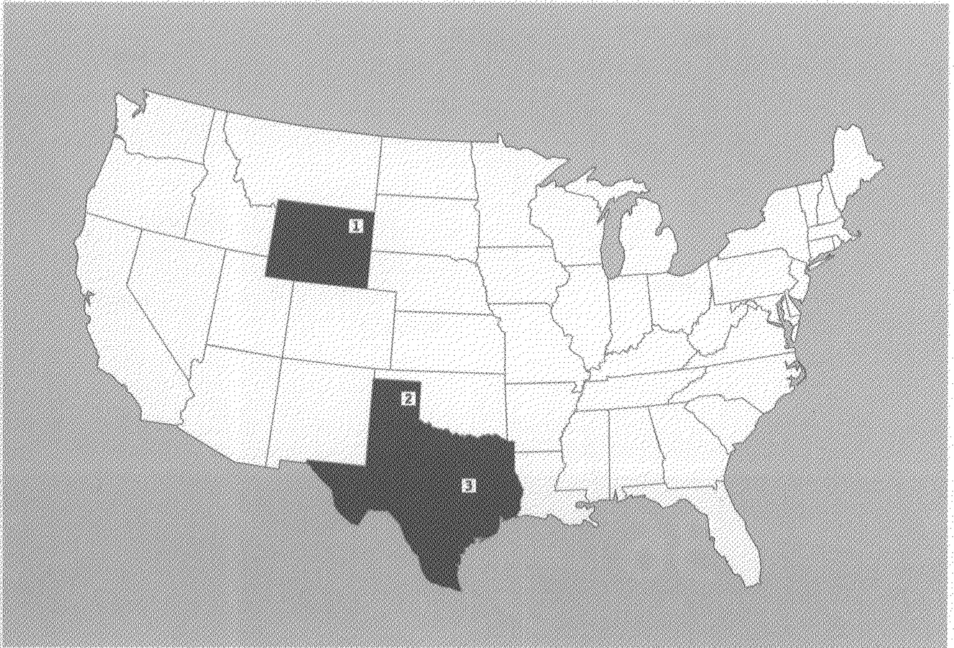
3 LONE STAR (NTGG) ACQUISITION

In July 2008, PVR Midstream completed an acquisition of substantially all of the assets of Lone Star Gathering L.P. located in the southern portion of the Fort Worth Basin of north Texas for approximately $169.0 million, plus contingent payments of $30.0 million and $25.0 million dependent upon achieving revenue targets by mid-2013.

The Lone Star acquisition expands the geographic scope of PVR Midstream into the Barnett Shale play in the Fort Worth Basin. The acquired assets consisted of approximately 129 miles of gas gathering pipelines and approximately 240,000 acres dedicated by active producers. Revenues for the acquired assets are derived primarily from fees charged for gathering, compression and transportation of natural gas, with the potential to increase revenues through the addition of processing, treating and other services.







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, 2008

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)**

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

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

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

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 $845,960,569 as of June 30, 2008 (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 25, 2009, 51,798,895 common units representing limited partner interests of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

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Part I

Item 1 *Business*

General

Penn Virginia Resource Partners, L.P. (NYSE: PVR) is a publicly traded Delaware limited partnership formed by Penn Virginia Corporation (NYSE: PVA), or Penn Virginia, in 2001 that is principally engaged in the management of coal and natural resource properties and the gathering and processing of natural gas in the United States. Both in our current limited partnership form and in our previous corporate form, we have managed coal properties since 1882. We currently conduct operations in two business segments: (i) coal and natural resource management and (ii) natural gas midstream.

Our operating income was $115.2 million in 2008, compared to $117.7 million in 2007 and $102.8 million in 2006. In 2008, our coal and natural resource management segment contributed $96.3 million, or 84%, to operating income, and our natural gas midstream segment contributed $18.9 million, or 16%, 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, 2008, we owned or controlled approximately 827 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 2008, our lessees produced 33.7 million tons of coal from our properties and paid us coal royalties revenues of $122.8 million, for an average royalty per ton of $3.65. Approximately 86% of our coal royalties revenues in 2008 were derived from coal mined on our properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price. The balance of our coal royalties revenues for the respective periods was derived from coal mined on our properties under leases containing fixed royalty rates that escalate annually. See "—Contracts—Coal and Natural Resource Management Segment" for a description of our coal leases.

Natural Gas Midstream Segment Overview

Our natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. As of December 31, 2008, we owned and operated natural gas midstream assets located in Oklahoma and Texas, including five natural gas processing facilities having 300 MMcfd of total capacity and approximately 4,069 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 Gas Services, LLC, or Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. 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 2008, system throughput volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 98.7 Bcf, or approximately 270 MMcfd.

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, which has not been the case since the third quarter of 2008. 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 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. For example, in May 2008, we acquired approximately 29 million tons of coal reserves and approximately 56 million board feet of hardwood timber in Central Appalachia for approximately $24.5 million.

- *Expand in areas that complement our coal royalty business.* Timber and coal infrastructure projects typically involve long-lived, fee-based 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. During 2008, expansion projects included completing the construction of two new natural gas processing plants, one in the panhandle of Texas and one in East Texas. In addition, during 2008 we completed $259.4 million of midstream acquisitions, including a 25% member interest in a major coalbed methane gatherer in Wyoming's Powder River Basin for $51.6 million and natural gas gathering assets in the Fort Worth Basin for approximately $164.3 million.

- *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. In the years ended December 31, 2008 and 2007, 28% and 29% 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. We expect volumes under our fee-based contracts to increase as a percentage of our total system throughput volumes in 2009 as a result of our 2008 acquisitions and new Crossroads plant, all of which are fee-based operations. 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 37% of our commodity-sensitive volumes in 2009. We generally target hedging 50 to 60% of our commodity-sensitive volumes for two years, although no such hedging agreements are currently in place for 2010.

- *Continue to expand our relationship with Penn Virginia.* Our relationship with Penn Virginia and its affiliates provides us with opportunities to grow our business. We will consider opportunities to provide midstream services for Penn Virginia's oil and gas business, PVOG, when appropriate. For example, the Crossroads natural gas processing plant we built in East Texas provides fee-based natural gas processing services to PVOG, as well as other producers. Our affiliation with Penn Virginia could also provide us a competitive advantage in pursuing acquisition opportunities, particularly opportunities involving the acquisition of multiple natural resource assets. Also, in 2008 we purchased approximately $61.8 million of PVG common units from affiliates of Penn Virginia to fund a portion of the purchase price of the acquisition of natural gas gathering assets in the Fort Worth Basin. See Note 15, "Related Party Transactions," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a more detailed description of our transactions with Penn Virginia.

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, 2008, 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. As of December 31, 2008, approximately 27% of our system throughput volumes were gathered or processed under gas purchase/keep-whole contracts, 45% were gathered or processed under percentage-of-proceeds contracts, and 28% 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. There is also a processing fee floor included in many of the gas purchase/keep-whole contracts that ensures a minimum processing margin should the actual margins fall below the floor.

In 2008, 27% and 13% of our natural gas midstream segment revenues and 22% and 11% of our total consolidated revenues resulted from two of our natural gas midstream customers, Conoco, Inc. and Louis Dreyfus Energy Services.

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

Percentage-of-Proceeds Arrangements. Under percentage-of-proceeds arrangements, we generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed-upon percentage of the proceeds of those sales based on either an index price or the price actually received for the gas and NGLs. Under these types of arrangements, our revenues and gross margins increase as natural gas prices and NGL prices increase, and our revenues and gross margins decrease as natural gas prices and NGL prices decrease.

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

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

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 ONEOK and at market hubs accessed by various interstate pipelines. Connect Energy Services, LLC, or Connect Energy, our wholly owned subsidiary, has earned fees from Penn Virginia Oil & Gas, L.P., or PVOG LP, a wholly owned subsidiary of Penn Virginia, since September 1, 2006, for marketing a portion of PVOG LP's natural gas production. Revenues from this business do not generate qualifying income for a publicly traded limited partnership, but we do not expect it to have an impact on our tax status, as it does not represent a significant percentage of our operating income. For the years ended December 31, 2008 and 2007, natural gas marketing activities generated $5.8 million and $4.6 million in net revenues.

Commodity Derivative Contracts. We utilize three-way collar 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 from favorable price movements.

A three-way collar contract consists of a collar contract plus a put option contract sold by us with a price below the floor price of the collar. The counterparty to a collar contract is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract.

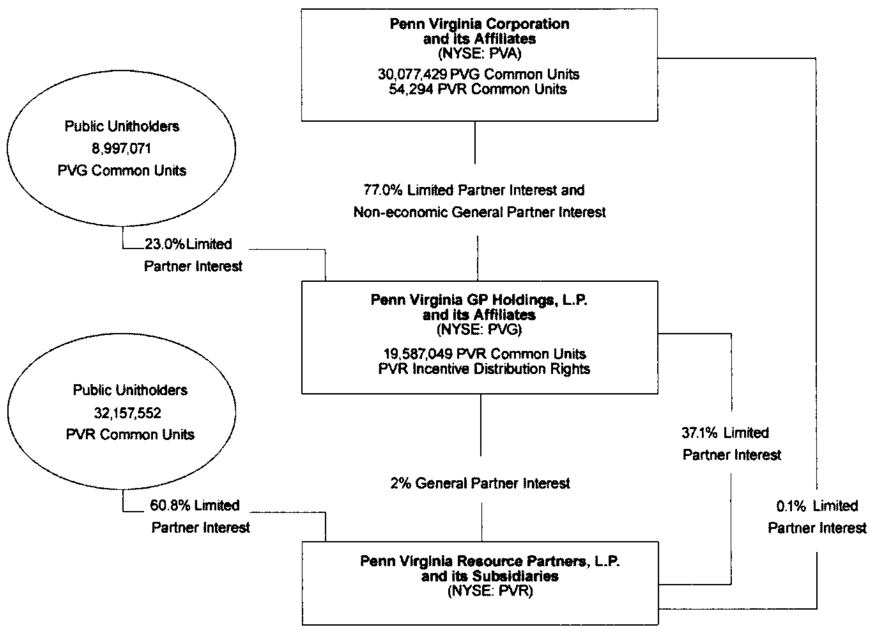
The additional put option sold by us requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put option price. By combining the collar contract with the additional put option, we are entitled to a net payment equal to the difference between the floor price of the collar contract and the additional put option price if the settlement price is equal to or less than the additional put option price. If the settlement price is greater than the additional put option price, the result is the same as it would have been with a collar contract only. If market prices are below the additional put option, we would be entitled to receive the market price plus the difference between the additional put option and the floor. See the natural gas midstream segment commodity derivative table in Item 7A –"Quantitative and Qualitative Disclosures About Market Risk – Price Risk." This strategy enables us to increase the floor and the ceiling prices of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option.

See Note 6, "Derivative Instruments," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a further description of our derivatives program.

Partnership Structure

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

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through 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, 2008:



Relationship with Penn Virginia Corporation

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

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

Partnership Distributions

Cash Distributions

We paid cash distributions of $1.82 per common unit during the year ended December 31, 2008. In the first quarter of 2009, we paid a cash distribution of $0.47 ($1.88 on an annualized basis) per common unit with respect to the fourth quarter of 2008. This distribution was unchanged from the previous distribution paid on November 14, 2008. For the remainder of 2009, we expect to pay quarterly cash distributions of at least $0.47 ($1.88 on an annualized basis) per common unit.

The following table reflects the allocation of total cash distributions paid by us during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands, except per unit information)		
Limited partner units	$ 89,207	$ 76,536	$ 61,427
General partner interest (2%)	1,820	1,562	1,254
Incentive distribution rights	20,049	11,551	4,273
Total cash distributions paid	$ 111,076	$ 89,649	$ 66,954
Total cash distributions paid per unit	$ 1.82	$ 1.66	$ 1.48

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.

Subordinated Units

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

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

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of our outstanding common units, our general partner has the right, which it may assign in whole or in part to any of its affiliates or us, but not the obligation, to acquire all 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 25, 2009, PVG and its affiliates owned 19,587,049 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 affiliates (including Penn Virginia and PVG), on the one hand, and us and our unitholders, on the other hand. Our general partner is controlled by PVG, which is in turn controlled by Penn Virginia. Accordingly, PVG (and Penn Virginia indirectly) has the ability to elect, remove and replace the directors and officers of our general partner. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners, Penn Virginia and PVG. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders.

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

Limits on Fiduciary Responsibilities

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

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

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

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

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

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

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

The EPA has promulgated rules, referred to as the "NOx SIP Call," that require coal-fired power plants and other large stationary sources in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule, or CAIR, which would have permanently capped nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010. CAIR required those states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered "cap-and-trade" program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state. The stringency of the caps under CAIR may have required many coal-fired sources to install additional pollution control equipment, such as wet scrubbers, to comply. This increased sulfur emission removal capability required by CAIR could have resulted in decreased demand for lower sulfur coal, which may have potentially driven down prices for lower sulfur coal. On July 11, 2008, the D.C. Circuit Court of Appeals vacated CAIR in its entirety. The EPA subsequently filed a petition for rehearing or, in the alternative, for a remand of the case without vacatur. On December 23, 2008, the Court issued an opinion to remand without vacating CAIR. Therefore, CAIR will remain in effect while the EPA conducts rulemaking to modify CAIR to comply with the Court's July 2008 opinion. The Court declined to impose a schedule by which the EPA must complete the rulemaking, but reminded the EPA that the Court does "...not intend to grant an indefinite stay of the effectiveness of this Court's decision." The EPA is considering its options on how to proceed.

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. In addition, various states have promulgated or are considering more stringent emission limits on mercury emissions from coal-fired electric generating units.

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

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

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

Depending on the ultimate resolution of these cases, demand for our coal could be affected, which could have an adverse effect on our coal royalties revenues.

Carbon Dioxide Emissions. The Kyoto Protocol to the United Nations Framework Convention on Climate Change calls for developed nations to reduce their emissions of greenhouse gases to 5% below 1990 levels by 2012. Carbon dioxide, which is a major byproduct of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005 for those nations that ratified the treaty. In 2002, the United States withdrew its support for the Kyoto Protocol, and the United States is not participating in this treaty. Since the Kyoto Protocol became effective, there has been increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. In addition, on April 2, 2007 the U.S. Supreme Court held in *Massachusetts v. EPA* that unless the EPA affirmatively concludes that greenhouse gases are not causing climate change, the EPA must regulate greenhouse gas emissions from new automobiles under the CAA. The Court remanded the matter to the EPA for further consideration. This litigation did not directly concern the EPA's authority to regulate greenhouse gas emissions from stationary sources, such as coal mining operations or coal-fired power plants. However, the Court's decision is likely to influence another lawsuit currently pending in the U.S. Court of Appeals for the District of Columbia Circuit, involving a challenge to the EPA's decision not to regulate carbon dioxide from power plants and other stationary sources under a CAA new source performance standard rule, which specifies emissions limits for new facilities. The court remanded that question to the EPA for further consideration in light of the ruling in *Massachusetts v. EPA*. On July 11, 2008, the EPA released an advanced notice of proposed rulemaking to regulate greenhouse gases under the CAA in response to the ruling in *Massachusetts v. EPA*. The notice did not contain a definitive proposal of what a greenhouse gas regulatory program would look like, but it presented the EPA's analyses and policy alternatives for consideration. The EPA stated that promulgating a program under the CAA would take years to issue. Any decision in this case or any regulatory action by the EPA limiting greenhouse gas emissions from power plants could impact the demand for our coal, which could have an adverse effect on our coal royalties revenues.

The permitting of a number of proposed new coal-fired power plants has also recently been contested by environmental organizations for concerns related to greenhouse gas emissions from new plants. 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. State regulatory authorities in Florida and North Carolina have also rejected the construction of new coal-fired power plants based on the uncertainty surrounding the potential costs associated with greenhouse gas emissions from these plants under future laws limiting the emission of carbon dioxide.

In addition, permits for several new coal-fired power plants without limits imposed on their greenhouse gas emissions have been appealed by environmental organizations to the 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. Likewise, in November 2008, in another case, *In re Deseret Power Electric Cooperative*, the EAB remanded the permitting decision back to the Region to reopen the record and reconsider whether carbon dioxide is a pollutant subject to regulation under the CAA with instructions to consider its nationwide implications. In December 2008, the EPA Administrator issued an interpretive rule determining that the phrase in the CAA "not subject to regulation" does not include pollutants for which only monitoring and reporting is required. Because carbon dioxide is such a pollutant, this interpretive rule has the effect of precluding any consideration of carbon dioxide emissions in connection with federal permitting under the CAA. Environmental groups filed a Petition for Reconsideration of the interpretive rule. On February 17, 2009, the EPA stated that it would grant the Petition for Reconsideration and allow public comment, but it declined to stay the effectiveness of the interpretive rule at that time.

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. This initiative aims to reduce emissions of carbon dioxide to levels roughly corresponding to average annual emissions between 2000 and 2004. The members of RGGI agreed to seek to establish in statute and/or regulation a carbon dioxide trading program and have each state's component of the regional program effective no later than December 31, 2008. 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.

Several different pieces of legislation were introduced in Congress in 2007 and 2008 to reduce greenhouse gas emissions in the United States. Newly elected President Obama, stated in his campaign that climate change policy would be a priority of his administration, and the Democratic majority in Congress has indicated that it will seek to enact legislation to reduce greenhouse gas emissions. It is possible that future federal and state initiatives to control and put a price on carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact our lessees' coal sales, and thereby have an adverse effect on our coal royalties revenues.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977, or SMCRA, and similar state statutes establish minimum national operational, reclamation and closure standards for all aspects of surface mining, as well as most aspects of deep mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. SMCRA also imposes on mine operators the responsibility of restoring the land to its original state and compensating the landowner for types of damages occurring as a result of mining operations, and require mine operators to post performance bonds to ensure compliance with any reclamation obligations. 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. This tax was set to expire on June 30, 2006, but the program was extended until September 30, 2021.

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

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

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

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

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

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

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

The Corps, Alex Energy, other impacted mining companies and mining associations appealed the March 23, 2007 ruling to the U.S. Court of Appeals for the Fourth Circuit. On February 13, 2009, the Fourth Circuit reversed and vacated the District Court's March 23, 2007 opinion and order that had rescinded the challenged permits and vacated the District Court's injunction of activity under those permits and reversed a related order by the District Court that would have required yet additional permits under the CWA. One of the three judges dissented in part from this decision and would have upheld the decision rescinding the permits and enjoining future activity but agreed with the other two judges on the other parts of the decision. This decision may be subject to further appellate review including by the Fourth Circuit itself. We are unable to predict the outcome of any further appellate review that may be obtained.

In December 2007, plaintiff environmental groups brought a similar suit against the issuance of a CWA Section 404 permit for a surface coal mine in the U.S. District Court for the Eastern District of Kentucky, alleging identical violations. The Corps has voluntarily suspended its consideration of the permit application in that case for agency re-evaluation. While the final outcome of these cases remains uncertain, if lawsuits challenging the use of valley fills ultimately limits or prohibits the mining methods or operations of our lessees, it could have an adverse effect on our coal royalties revenues. In addition, it is possible that similar litigation affecting recently issued, pending or future individual or general CWA Section 404 permits relevant to the mining and related operations of our lessees could adversely impact our coal royalties revenues.

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 have brought lawsuits challenging the rule. It is unclear what impact the rule will have on the previously discussed lawsuits related to valley fills or any mining operations undertaken by our lessees in the future.

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.

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

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

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

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

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

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

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

Natural Gas Midstream Segment

General Regulation. Our natural gas gathering facilities generally are exempt from the Federal Energy Regulatory Commission's, or the FERC, jurisdiction under the Natural Gas Act of 1938, or the NGA, but FERC regulation nevertheless could significantly affect our gathering business and the market for our services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which our gathering pipelines deliver. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

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

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

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

Texas and Oklahoma administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, or the NGPSA, which requires certain 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 157 employees who directly supported our operations at December 31, 2008. Our general partner considers current employee relations to be favorable.

Available Information

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

Common Abbreviations and Definitions

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

Bbl	a standard barrel of 42 U.S. gallons liquid volume
Bcf	one billion cubic feet
Bcfe	one billion cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
BTU	British thermal unit
MBbl	one thousand barrels
Mbf	one thousand board feet

Mcf	one thousand cubic feet
Mcfe	one thousand cubic feet equivalent
MMBbl	one million barrels
MMbf	one million board feet
MMBtu	one million British thermal units
MMcf	one million cubic feet
MMcfd	one million cubic feet per day
MMcfe	one million cubic feet equivalent
NGL	natural gas liquid
NYMEX	New York Mercantile Exchange
Probable coal reserves	those reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are 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
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
Proven coal reserves	those 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

Item 1A *Risk Factors*

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

Risks Inherent in an Investment in Us

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

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

- the amount of coal our lessees are able to produce;
- the price at which our lessees are able to sell the coal;
- our lessees' timely receipt of payment from their customers;
- the amount of natural gas transported in our gathering systems;
- the amount of throughput in our processing plants;
- the price of and demand for natural gas;
- the price of and demand for NGLs;
- the relationship between natural gas and NGL prices;
- the fees we charge and the margins we realize for our natural gas midstream services; and
- our hedging activities.

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

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

Because of these factors, we may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. The amount of cash that we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record profits.

The current deterioration of the credit and capital markets may adversely impact our ability to obtain financing on acceptable terms or obtain funding under our revolving credit facility. This may hinder or prevent us from implementing our development plan, completing acquisitions or otherwise meeting our future capital needs.

Global financial markets have been experiencing extreme volatility and disruption, and the debt and equity capital markets have been exceedingly distressed. These issues have made, and will likely continue to make, it difficult to obtain financing. In particular, the cost of raising money in the equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. The current global economic downturn may adversely impact our ability to issue additional equity in the future at prices which will not be dilutive to our existing unitholders or preclude us from issuing equity at all.

Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. Moreover, even if lenders and institutional investors are willing and able to provide adequate funding, interest rates may rise in the future and therefore increase the cost of borrowing we incur on any of our floating rate debt. In addition, we may be unable to obtain adequate funding under our revolving credit facility, or the Revolver, because (i) our lending counterparties may be unwilling or unable to meet their future funding obligations or (ii) our borrowing capacity may be reduced if there is an extensive decline in our EBITDA. See "Long-Term Debt" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," for a more detailed description of our debt covenants and our borrowing capacity.

Due to these factors, we cannot be certain that future funding will be available if needed and to the extent required on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, it might adversely affect our development plan as currently anticipated and our ability to complete acquisitions, each of which could have a material adverse effect on our business, results of operations or financial condition.

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

While we are permitted by our partnership agreements to incur debt to pay distributions to our unitholders, our payment of principal and interest on such indebtedness will reduce our cash available for distribution to our unitholders. Furthermore, our debt agreement, which currently consists solely of the Revolver, contains covenants limiting our ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions to our partners. The Revolver also contains covenants requiring us not to exceed certain specified financial ratios. We are prohibited from making any distribution to our partners if such distribution would cause an event of default or otherwise violate a covenant under the Revolver. Additionally, the 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 or vote on our general partner's directors. The owner of our general partner owns a sufficient number of common units to allow it to prevent the removal of our general partner.

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

Our general partner may cause us to issue additional common units or other equity securities without 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 board of directors and officers of our general partner and to control the decisions taken by the board of directors and officers.

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

Penn Virginia and its affiliates, including PVG, own an approximately 37% limited partner interest in us and own and control our general partner. Conflicts of interest may arise between our general partner and its affiliates (including Penn Virginia and PVG), on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- Our general partner is allowed to take into account the interests of parties other than us, such as Penn Virginia and PVG, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.
- Our general partner 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, three of our general partner's seven directors and three of its five officers are also directors or officers of PVG's general partner, which has fiduciary duties to manage the business of PVG in a manner beneficial to PVG and its unitholders, including Penn Virginia. Consequently, these directors and officers may encounter situations in which their fiduciary obligations to us on the one hand, and PVG, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

In addition, our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions that might otherwise constitute a breach of our general partner's fiduciary duties owed to unitholders. By purchasing our units, 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.

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

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

Our general partner has a call right that may require 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. Affiliates of our general partner currently own 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 impact of the current deterioration 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 the deterioration, 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, 2008, five primary operators, each with multiple leases, accounted for 65% of our coal royalties revenues and 9% of our total consolidated revenues. If any of these operators enters bankruptcy or decides to cease operations or significantly reduces its production, our coal royalties revenues would be reduced.

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

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

Because our reserves decline as our lessees mine our coal, our future success and growth depends, in part, upon our ability to acquire additional coal reserves that are economically recoverable. The current deterioration in the global economy, including financial markets, and the consequential adverse effect on credit availability is adversely impacting our access to new capital and credit availability. Depending on the longevity and ultimate severity of this deterioration, our ability to make acquisitions may be significantly adversely affected. 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, 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 third largest mine on the basis of coal production for the year ended December 31, 2008. All of our lessees could become increasingly unionized in the future. If some or all of our lessees' non-unionized operations were to become unionized, it could adversely affect their productivity and increase the risk of work stoppages. In addition, our lessees' operations may be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our lessees' operations. Any further unionization of our lessees' employees could adversely affect the stability of production from our coal reserves and reduce our coal royalties revenues.

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

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

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

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

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

According to the U.S. Department of Energy, domestic electric power generation accounted for approximately 90% of domestic coal consumption in 2007. The amount of coal consumed for domestic electric power generation is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants such as nuclear, natural gas, fuel oil and hydroelectric power and environmental and other governmental regulations. We believe that most new power plants will be built to produce electricity during peak periods of demand. Many of these new power plants will likely be fired by natural gas because of lower construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of the CAA may result in more electric power generators shifting from coal to natural gas-fired power plants. See Item 1, "Business—Government Regulation and Environmental Matters—Coal and Natural Resource Management Segment—Air Emissions."

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

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants, which are the ultimate consumers of the coal our lessees produce. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. 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."

Concerns about the environmental impacts of fossil-fuel emissions, including perceived impacts on global climate change, are resulting in increased regulation of emissions of greenhouse gases in many jurisdictions and increased interest in and the likelihood of further regulation, which could significantly affect our coal royalties revenues.

Global climate change continues to attract considerable public and scientific attention. Several widely publicized scientific reports have engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. Legislative attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. Such legislation was introduced in Congress in 2006, 2007 and 2008 to reduce greenhouse gas emissions in the United States and further proposals or amendments are likely to be offered in the future. Although the United States Supreme Court's recent decision in *Massachusetts v. Environmental Protection Agency* related to new motor vehicles, the reasoning of the decision could affect regulation of carbon dioxide emissions under other federal regulatory programs, including those that regulate emissions from coal-fired power plants. Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired power plants. See Item 1, "Business—Governmental Regulation and Environmental Matters—Coal and Natural Resource Management Segment—Air Emissions." Enactment of laws, passage of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions could result in electric generators switching from coal to other fuel sources. This may adversely affect the use of and demand for fossil fuels, particularly coal.

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

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

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

To dispose of mining overburden generated from surface mining activities, our lessees often need to obtain government approvals, including CWA Section 404 permits to construct valley fills and sediment control ponds. Ongoing uncertainty over which waters are subject to the CWA may adversely impact our lessees' ability to secure these necessary permits. In addition, a 2007 decision by a U.S. District Court in West Virginia invalidated a permit issued to one of our lessees for the Republic No. 2 Mine and enjoined our lessee, Alex Energy, Inc., from taking any further actions under this permit. This ruling was appealed and the appellate court reversed and vacated the district court's order. It is unclear if this ruling will be appealed or if the permits will be challenged on other grounds. Uncertainty over the correct legal standard for issuing Section 404 permits may lead to rulings invalidating other permits, additional challenges to various permits and additional delays and costs in applying for and obtaining new permits that could ultimately have an adverse effect on our coal royalties revenues. See Item 1, "Business—Government Regulation and Environmental Matters—Coal and Natural Resource Management Segment—Clean Water Act," for more information about the litigation described above.

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

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

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

The coal and natural resource management segment may record impairment losses on its long-lived assets.

The coal and natural resource management segment has completed a number of acquisitions in recent years. See Note 3, "Acquisitions" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a description of the our coal and natural resource management 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.

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 2008, 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 impact of the current deterioration in 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 has been and continues to be critical factors in our ability to grow. The current deterioration in the global economy, including financial markets, and the consequential adverse effect on credit availability is adversely impacting our access to new capital and credit availability. Depending on the longevity and ultimate severity of the deterioration, 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. Our access to such capital is currently adversely impacted by the deterioration in the global economy, including financial and credit markets. 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 the year ended December 31, 2008, 40% of our natural gas midstream segment revenues and 33% of our total consolidated revenues related to two natural gas midstream segment customers. 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 natural gas or NGL prices were to rise (or 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 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 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. See Note 3, "Acquisitions," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," 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.

The North Texas Gas Gathering System has a limited operating history and has system throughput volumes representing only a small percentage of its total design capacity.

The assets comprising the North Texas Gas Gathering System were all built after June 2005 and, consequently, have a limited operating history. In addition, the total current system throughput volumes on the North Texas Gas Gathering System represent only a small percentage of its total design capacity. Accordingly, the North Texas Gas Gathering System to date has generated only modest levels of revenues. In order for our 2008 acquisition of substantially all of the assets of Lone Star Gathering, L.P., or Lone Star, to be a success, we will need to substantially increase system throughput volumes over historical levels. Any such increase will require a significant increase in our producers' production in the areas served by the North Texas Gas Gathering System, and no assurance can be given that they will be able to so increase production or sustain such an increase over time. In particular, while producers are currently actively drilling in Johnson and Hill Counties, we expect that the success of the Lone Star acquisition will require producers to expand their drilling and production activities in Bosque, Hamilton, Somervell and Erath Counties. We also will need to operate the North Texas Gas Gathering System reliably and efficiently, in the absence of any significant operating history on which to draw. While the North Texas Gas Gathering System is modern, there may be unexpected operating and capital expenditures necessary to operate it properly. In addition, we will need to effectively integrate the North Texas Gas Gathering System within our existing natural gas midstream business, both operationally and administratively. We cannot assure that these endeavors will be successful. If we are unsuccessful, the revenues from the North Texas Gas Gathering System will be adversely affected.

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 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. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, or IRS, on this or any other matter affecting us.

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

If we were treated as a corporation for federal income tax purposes for any taxable year for which the statute of limitations remains open or for any future 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 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 would materially and adversely affect our ability to make payments on our debt.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we are subject to 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 will reduce the cash available for distribution to our unitholders.

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

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

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

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

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

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.

Due to a number of factors, including our inability to match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from 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. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because a unitholder whose common units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned common units, such unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller 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 Penn Virginia, PVG or any of their affiliates, sold or transferred their partner interests in us. While we would continue our existence as a Delaware limited partnership, our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A technical termination would not effect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a technical termination occurred.

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 do 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.

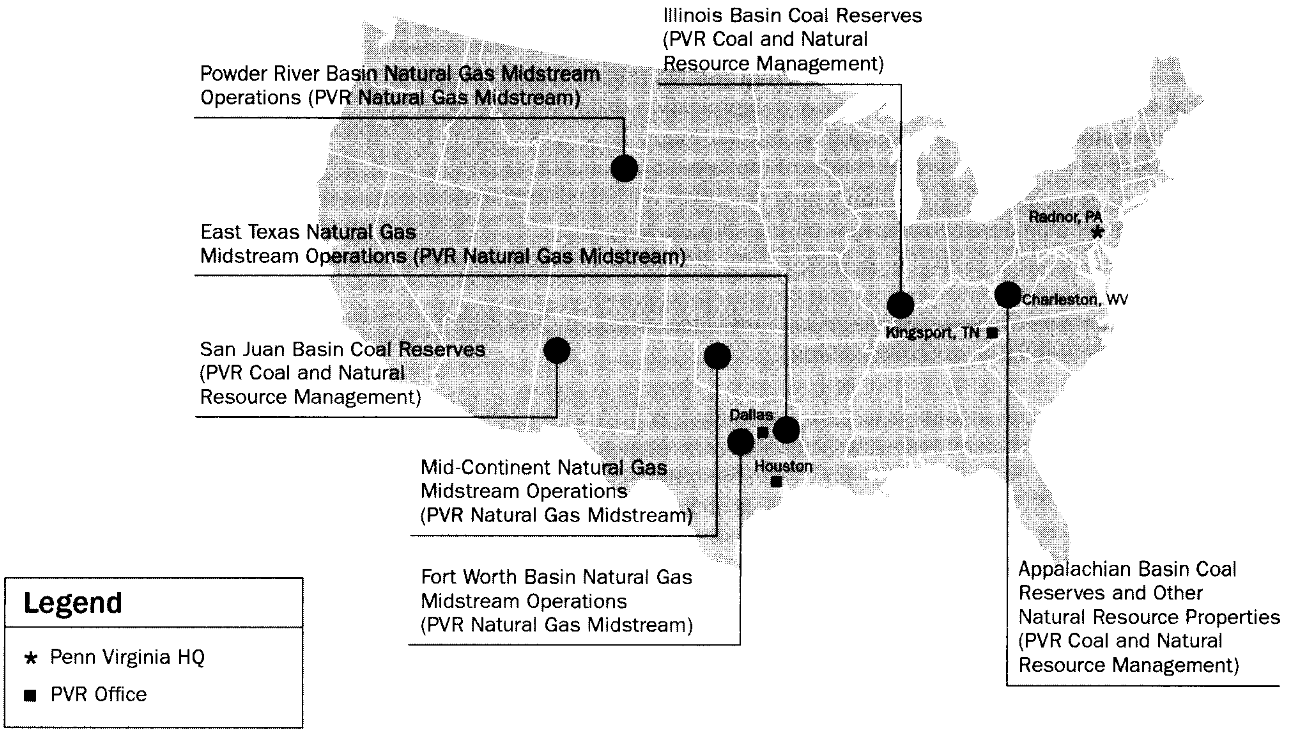
Item 1B *Unresolved Staff Comments*

We received no written comments from the SEC staff regarding our periodic or current reports under the Exchange Act within 180 days before the end of our fiscal year ended December 31, 2008.

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, 2008:



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

Facilities

Our general partner provides all of our office space, except for a field office that we own near Charleston, West Virginia. We believe that our properties are adequate for our current needs.

Coal Reserves and Production

As of December 31, 2008, we owned or controlled approximately 827 million tons of proven and probable coal reserves located on approximately 495,000 acres (including fee and leased acreage) in Illinois, Kentucky, New Mexico, Virginia and West Virginia. Our coal reserves are in various surface and underground mine seams located on the following properties:

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

Coal reserves are coal tons that can be economically extracted or produced at the time of determination considering legal, economic and technical limitations. All of the estimates of our coal reserves are classified as proven and probable reserves. Proven and probable 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 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, 2008, our lessees operated 32 surface mines and 43 underground mines. Approximately 52% of the coal produced from our properties in 2008 came from underground mines and 48% came from surface mines. Most of our lessees use the continuous mining method in all of their underground mines located on our properties. In continuous mining, main airways and transportation entries are developed and remote-controlled continuous miners extract coal from "rooms," leaving "pillars" to support the roof. Shuttle cars transport coal to a conveyor belt for transportation to the surface. In several underground mines, our lessees use two continuous miners running at the same time, also known as a supersection, to improve productivity and reduce unit costs.

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 table shows our most important coal producing seams by property at December 31, 2008:

Area	Property	State	Producing Mine Types	Seam Name	Height Range (ft.)
Central Appalachia	Wise	VA, KY	Surface, Underground	Parsons	1.00 - 6.00
				Phillips	1.50 - 6.00
				Low Splint	1.00 - 5.50
				Taggart/Marker	1.50 - 9.00
				U. Wilson	1.50 - 5.50
				Kelly/Imboden	1.00 - 7.50
	Buchanan	VA	Underground	Hagy	2.50 - 3.50
	Wayland	KY	Underground	U. Elkhorn No. 2	2.33 - 4.00
	Coal River, Fields Creek	WV	Surface, Underground	Coalburg	1.00 - 11.00
				Winifrede	1.00 - 6.50
				Cedar Grove	1.00 - 5.50
				No. 2 Gas	1.50 - 8.00
	Alloy	WV	Underground	Powellton	2.50 - 4.50
				Eagle	2.50 - 3.00
	Coal River, Cabin Creek	WV	Surface	Coalburg	1.00 - 5.00
				Buffalo Creek	1.00 - 5.50
				Winifrede	1.00 - 10.00
	Coal River, West Coal River	WV	Surface, Underground	Stockton	4.00 - 12.00
				No. 2 Gas	2.50 - 4.00
	Huff Creek/Toney Fork	WV	Surface, Underground	Coalburg	5.00 - 16.00
				U. Alma	3.00 - 4.00
	Spruce Laurel *	WV	Underground	Coalburg	4.00 - 7.00
	Powell Mountain	VA,KY	Surface, Underground	Splint Seams	2.00 - 2.75
			Underground	Darby	2.50 - 3.00
Northern Appalachia	Federal No 2	WV	Underground	Pittsburgh	6.50 - 9.50
	Upshur		Surface	Pittsburgh	3.00 - 6.50
Illinois Basin	Green River	KY	Surface, Underground	KY No. 9	3.00 - 5.00
	Allied	KY	Underground	KY No. 9	3.00 - 5.00
	Royal Falcon	IL	Underground	Herrin No. 6	5.00 - 8.00
San Juan Basin	Lee Ranch	NM	Surface	Cleary Seams	8.00 - 16.00

* There was no production from this property in 2008.

The following tables set forth production data for the years ended December 31, 2008, 2007 and 2006 and reserve information as of December 31, 2008 with respect to each of our properties:

Property	Production for the Year Ended December 31, 2008	2007	2006
	(tons in millions)		
Central Appalachia	19.6	18.8	20.2
Northern Appalachia	3.6	4.2	5.0
Illinois Basin	4.6	3.8	2.5
San Juan Basin	5.9	5.7	5.1
Total	33.7	32.5	32.8

Property	Proven and Probable Reserves as of December 31, 2008 Underground	Surface	Total	Steam	Metallurgical	Total
	(tons in millions)					
Central Appalachia	440.8	149.0	589.8	502.5	87.3	589.8
Northern Appalachia	26.4	-	26.4	26.4	-	26.4
Illinois Basin	154.9	10.8	165.7	165.7	-	165.7
San Juan Basin	-	44.9	44.9	44.9	-	44.9
Total	622.1	204.7	826.8	739.5	87.3	826.8

Of the approximately 827 million tons of proven and probable coal reserves to which we had rights as of December 31, 2008, we owned the mineral interests and the related surface rights to 460.3 million tons, or 56%, and we owned only the mineral interests to 197.1 million tons, or 24%. We leased the mineral rights to the remaining 169.4 million tons, or 20%, 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 2008, our aggregate expenses to third-party surface and mineral owners were $9.5 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, 2008:

Property	Owned	Leased	Total Controlled
		(tons in millions)	
Central Appalachia	454.4	135.4	589.8
Northern Appalachia	26.4	-	26.4
Illinois Basin	135.5	30.2	165.7
San Juan Basin	41.1	3.8	44.9
Total	657.4	169.4	826.8

The following table sets forth our coal reserve activity for each of our coal properties for the years ended December 31, 2008, 2007 and 2006:

	2008	2007	2006
		(tons in millions)	
Reserves - beginning of year	818.4	765.4	689.1
Purchase of coal reserves	34.6	60.0	96.2
Tons mined by lessees	(33.7)	(32.5)	(32.8)
Revisions of estimates and other	7.5	25.5	12.9
Reserves - end of year	826.8	818.4	765.4

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, 2008, approximately 25% of our reserves met compliance standards for the CAA and 38% 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 as of December 31, 2008:

	Sulfur Content Reserves as of December 31, 2008						Typical Clean Coal Quality Heat Content		
Property	Compliance (1)	Low Sulfur (2)	Medium Sulfur	High Sulfur	Sulfur Unclassified	Total	Btu per Pound (3)	Sulfur (%)	Ash (%)
			(tons in millions)						
Central Appalachia	203.4	287.4	209.4	84.2	8.8	589.8	14,041	1.04	6.50
Northern Appalachia	-	-	-	26.4	-	26.4	12,900	2.58	8.80
Illinois Basin	-	-	-	165.7	-	165.7	11,034	2.39	8.32
San Juan Basin	-	28.1	12.2	4.6	-	44.9	9,200	0.89	17.80
Total	203.4	315.5	221.6	280.9	8.8	826.8			

(1) Compliance coal is low sulfur coal which, when burned, emits less than 1.2 pounds of sulfur dioxide per million BTU. Compliance coal meets the sulfur dioxide emission standards imposed by Phase II of the CAA without blending in other coals or using sulfur dioxide reduction technologies. Compliance coal is a subset of low sulfur coal and is, therefore, also reported within the amounts for low sulfur coal.

(2) Includes compliance coal.

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

The following table shows the proven and probable coal reserves we lease to mine operators by property as of December 31, 2008:

Property	Proven and Probable Reserves As of December 31, 2008 Total Controlled	Leased to Operators	Percentage Leased
	(tons in millions)		
Central Appalachia	589.8	501.9	85%
Northern Appalachia	26.4	26.0	98%
Illinois Basin	165.7	106.5	64%
San Juan Basin	44.9	44.9	100%
Total	826.8	679.3	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. Approximately 26% of our forestland is located on the approximately 62,000 acres in West Virginia that we acquired in September 2007. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments," for a discussion of our forestland acquisition. The balance of our forestland is located on properties that also contain our coal reserves.

We own royalty interests in approximately 10.9 Bcfe of proved oil and gas reserves located on approximately 56,000 acres in Kentucky, Virginia and West Virginia. Approximately 85% of our oil and gas royalty interests are associated with the leases of property in eastern Kentucky and southwestern Virginia that we acquired from Penn Virginia in October 2007. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments," for a discussion of our oil and gas royalty interest acquisition.

Natural Gas Midstream Systems

Our natural gas midstream 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 five natural gas processing facilities having 300 MMcfd of total capacity as of December 31, 2008. Our natural gas midstream operations currently include four natural gas gathering and processing systems and two 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; and (vi) the Hamlin gathering and processing facilities in west-central Texas. These assets included approximately 4,069 miles of natural gas gathering pipelines as of December 31, 2008. 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.

The following table sets forth information regarding our natural gas midstream assets:

Asset	Type	Approximate Length (Miles)	Approximate Wells Connected	Current Processing Capacity (MMcfd)	Year Ended December 31, 2008 Average System Throughput (MMcfd)		Utilization of Processing Capacity (%)
Panhandle System	Gathering pipelines and processing facility	1,648	1,037	160	181.0	(1)	100%
Crossroads System	Gathering pipelines and processing facility	8	-	80	36.0		45%
Crescent System	Gathering pipelines and processing facility	1,698	850	40	22.5		56%
Hamlin System	Gathering pipelines and processing facility	506	243	20	6.3		32%
Arkoma System	Gathering pipelines	78	81	-	14.0	(2)	
North Texas Gas Gathering System	Gathering pipelines	131	39	-	10.0	(2)	
		4,069	2,250	300	269.8		

(1) Includes gas processed at other systems connected to the Panhandle System via the pipeline acquired in June 2006.
(2) Gathering-only volumes.

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 1,648 miles of natural gas gathering pipelines, ranging in size from two to 16 inches in diameter, and the Beaver and Spearman natural gas processing plants. Included in the system is an 11-mile, 10-inch diameter, FERC-jurisdictional residue line.

The Panhandle System is comprised of a number of major gathering systems and sixteen related compressor stations that gather natural gas, directly or indirectly, to the Beaver and Spearman plants in Beaver County, Oklahoma. These include the Beaver, Perryton, Spearman, Wolf Creek/Kiowa Creek and Ellis systems. These gathering systems are located in Beaver, Ellis and Harper Counties in Oklahoma and Hansford, Hemphill, Hutchinson, Lipscomb, Ochiltree and Roberts 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 60 MMcfd of inlet capacity. The plant is capable of operating in high ethane recovery mode or in ethane rejection mode and will have instrumentation allowing for unattended operation of up to 16 hours per day. In conjunction with the construction of the Spearman plant, three new gas compressor stations have been constructed on the Spearman gathering system. These compressor stations will allow for more efficient operation of the Spearman system and provide lower wellhead pressures.

We placed the Spearman plant in service in February 2008. The Spearman plant processes gas gathered on the Panhandle System. This plant was built to process the gas that was previously bypassing the Beaver plant.

Natural Gas Supply. The supply in the Panhandle System comes from approximately 215 producers pursuant to 337 contracts. The average gas quality on the Panhandle System for 2008 was 2.6 gallons of NGLs per delivered Mcf.

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

The residue gas from the Spearman plant is delivered into Northern Natural Gas pipelines for sale or transportation to market. The NGLs produced at the Spearman plant is 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.

Crossroads System

General. In April 2008, we completed construction on the Crossroads System, which is a natural gas gathering system located in the southeast portion of Harrison County, 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 transport 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. The natural gas on the Crossroads System originates from the Bethany Field from where we have contracted with two producers. The average gas quality on the Crossroads System is 1.3 gallons of NGLs per delivered Mcf.

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 1,698 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. Sixteen compressor stations are operating across the Crescent System.

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

Natural Gas Supply. The gas supply on the Crescent System is primarily gas associated with the production of oil or "casinghead gas" from the mature Sooner Trend. Wells in this region producing casinghead gas are generally characterized as low volume, long-lived producers of gas with large quantities of NGLs. The supply in the Crescent System comes from approximately 264 producers pursuant to 419 contracts. The average gas quality on the Crescent System for 2008 was 5.1 gallons of NGLs per delivered Mcf.

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

Hamlin System

General. The Hamlin System is a natural gas gathering system stretching over eight counties in West Central Texas. The system consists of approximately 506 miles of natural gas gathering pipelines, ranging in size from two to 12 inches in diameter and with current capacity of approximately 20 MMcfd, and the Hamlin natural gas processing plant located in Fisher County, Texas. Eight compressor stations are operating across the system.

Natural Gas Supply. The gas on the Hamlin System is primarily gas associated with the production of oil or "casinghead gas." The supply on the Hamlin System comes from approximately 111 producers pursuant to 140 contracts. The average gas quality on the Hamlin System for 2008 was 8.7 gallons of NGLs per delivered Mcf.

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

North Texas Gas Gathering System

General. On July 17, 2008, we completed the Lone Star acquisition. Lone Star's assets are located in the southern portion of the Fort Worth Basin of North Texas and include approximately 131 miles of gas gathering pipelines and approximately 240,000 acres dedicated by active producers. The Lone Star acquisition 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. Since the acquisition, we have averaged 10 MMcfd in gathered volumes.

Item 3 *Legal Proceedings*

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

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2008.

Part II

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

Market Information

Our common units are traded on the NYSE under the symbol "PVR." The high and low sales prices (composite transactions) for each fiscal quarter in 2008 and 2007 were as follows:

Quarter Ended	High	Low
December 31, 2008	$19.85	$8.34
September 30, 2008	$27.38	$15.08
June 30, 2008	$30.15	$24.69
March 31, 2008	$29.00	$18.00
December 31, 2007	$29.54	$23.71
September 30, 2007	$32.90	$23.58
June 30, 2007	$31.69	$26.69
March 31, 2007	$28.89	$24.56

Equity Holders

As of February 6, 2009, there were 238 record holders and approximately 29,200 beneficial owners (held in street name) of our common units.

Distributions

For the year ended December 31, 2008, we paid cash distributions of $1.82 per common unit. The quarterly cash distributions paid in 2008 and 2007 were as follows:

Period Covered by Distribution	Record Date	Payment Date	Amount Per Unit
Third quarter 2008	November 6, 2008	November 14, 2008	$0.47
Second quarter 2008	August 4, 2008	August 14, 2008	$0.46
First quarter 2008	May 5, 2008	May 15, 2008	$0.45
Fourth quarter 2007	February 4, 2008	Februay 14, 2008	$0.44
Third quarter 2007	November 5, 2007	November 14, 2007	$0.43
Second quarter 2007	August 6, 2007	August 14, 2007	$0.42
First quarter 2007	May 4, 2007	May 15, 2007	$0.41
Fourth quarter 2006	February 5, 2007	February 14, 2007	$0.40

If cash distributions per unit exceed $0.275 in any quarter, our general partner will receive a higher percentage of the cash we distribute in excess of that amount in increasing percentages up to 50%. See Item 1, "Business—Partnership Distributions—Incentive Distribution Rights." On February 13, 2009, we paid a cash distribution with respect to the fourth quarter of 2008 of $0.47 per common unit. For the remainder of 2009, we expect to pay quarterly cash distributions of at least $0.47 ($1.88 on an annualized basis) per common unit.

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

Item 6 ***Selected Financial Data***

The following selected historical financial information was derived from our consolidated financial statements as of December 31, 2008, 2007, 2006, 2005 and 2004, and for each of the years then ended. The selected financial data should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 7, "Management's

Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data."

	Year Ended December 31,				
	2008	2007	2006	2005 (1)	2004
	(in thousands, except per unit data)				
Revenues (2)	$ 881,580	$ 549,445	$ 517,891	$ 446,348	$ 75,630
Expenses (2)	$ 766,338	$ 431,720	$ 415,071	$ 368,258	$ 35,111
Operating income	$ 115,242	$ 117,725	$ 102,820	$ 78,090	$ 40,519
Net income	$ 104,500	$ 56,623	$ 73,928	$ 51,161	$ 34,315
Net income per limited partner unit, basic and diluted	$ 1.67	$ 0.96	$ 1.56	$ 1.22	$ 0.93
Total assets (3)	$ 1,218,819	$ 931,279	$ 714,023	$ 657,879	$ 284,435
Long-term debt	$ 568,100	$ 399,153	$ 207,214	$ 246,846	$ 112,926
Cash flows provided by operating activities	$ 139,176	$ 127,824	$ 107,344	$ 93,172	$ 54,782
Distributions paid	$ 111,076	$ 89,649	$ 66,954	$ 51,949	$ 39,191
Distributions paid per unit	$ 1.82	$ 1.66	$ 1.48	$ 1.24	$ 1.06

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

(2) In 2008, we recorded $127.9 million of natural gas midstream revenue 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, nor do they impact operating income.

(3) Total assets for the year ended December 31, 2008 include the effects of the Lone Star acquisition, which expanded the geographic scope of the natural gas midstream segment into the Barnett Shale play in the Fort Worth Basin. See Note 3, "Acquisitions," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," 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 the accompanying notes in Item 8, "Financial Statements and Supplementary Data."

Overview of Business

We are a publicly traded Delaware limited partnership formed by Penn Virginia in 2001 that is principally engaged in the management of coal and natural resource properties and the gathering and processing of natural gas in the United States. Both in our current limited partnership form and in our previous corporate form, we have managed coal properties since 1882. We currently conduct operations in two business segments: (i) coal and natural resource management and (ii) natural gas midstream. Our operating income was $115.2 million in 2008, compared to $117.7 million in 2007 and $102.8 million in 2006. In 2008, our coal and natural resource management segment contributed $96.3 million, or 84%, to operating income, and our natural gas midstream segment contributed $18.9 million, or 16%, to operating income.

The following table presents a summary of certain financial information relating to our segments for the years ended December 31, 2008, 2007 and 2006:

	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
		(in thousands)	
For the Year Ended December 31, 2008:			
Revenues	$ 153,327	$ 728,253	$ 881,580
Cost of midstream 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
For the Year Ended December 31, 2007:			
Revenues	$ 111,639	$ 437,806	$ 549,445
Cost of midstream gas purchased	-	343,293	343,293
Operating costs and expenses	20,138	26,777	46,915
Depreciation, depletion and amortization	22,690	18,822	41,512
Operating income	$ 68,811	$ 48,914	$ 117,725
For the Year Ended December 31, 2006:			
Revenues	$ 112,981	$ 404,910	$ 517,891
Cost of midstream gas purchased	-	334,594	334,594
Operating costs and expenses	19,138	23,846	42,984
Depreciation, depletion and amortization	20,399	17,094	37,493
Operating income	$ 73,444	$ 29,376	$ 102,820

Coal and Natural Resource Management Segment

As of December 31, 2008, we owned or controlled approximately 827 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 2008, our lessees produced 33.7 million tons of coal from our properties and paid us coal royalties revenues of $122.8 million, for an average royalty per ton of $3.65. Approximately 86% of our coal royalties revenues in 2008 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, our average royalty per ton also changes because the majority of our lessees pay royalties based on the gross sales prices of the coal mined. Most of our coal is sold by our lessees under contracts with a duration of one year or more; therefore, changes to our average royalty occur as our lessees' contracts are renegotiated.

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.

The future impact of the current deterioration 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 the deterioration, demand for coal may decline, which could adversely effect production and pricing for coal mined by our lessees, and, consequently, adversely affect the royalty income received by us and our ability to make cash distributions to our limited partners and to PVG, the owner of our general partner.

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, 2008, we owned and operated natural gas midstream assets located in Oklahoma and Texas, including five natural gas processing facilities having 300 MMcfd of total capacity and approximately 4,069 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 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 2008, system throughput volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 98.7 Bcf, or approximately 270 MMcfd. In 2008, 27% and 13% of our natural gas midstream segment revenues and 22% and 11% of our total consolidated revenues related to two of our natural gas midstream customers, Conoco, Inc. and Louis Dreyfus Energy Services.

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 2008, our natural gas midstream segment made aggregate capital expenditures of $333.3 million, primarily related to our 25% member interest acquisition of Thunder Creek, the Lone Star acquisition, acquisition of pipeline assets in the Anadarko Basin of Oklahoma and Texas and our capacity expanding capital expenditures related to the Spearman and Crossroads plants. For a more detailed discussion of our acquisitions and investments, see "—Acquisitions and Investments."

Revenues, profitability and the future rate of growth of our natural gas midstream segment are highly dependent on market demand and prevailing NGL and natural gas prices. Historically, changes in the prices of most NGL products have generally correlated with changes in the price of crude oil. NGL and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for NGL products and natural gas market demand. The current deterioration in global economy, including financial and credit markets, will likely result in a decrease in worldwide demand for oil and domestic demand for natural gas and NGLs. Depending on the longevity and ultimate severity of the deterioration, NGL production from our processing plants could decrease and adversely effect our natural gas midstream processing income and our ability to make cash distributions.

Acquisitions and Investments

Set forth below are brief descriptions of the significant acquisitions that we have made in the years ended December 31, 2008, 2007 and 2006.

Coal and Natural Resource Management Segment

In May 2008, we acquired fee ownership of approximately 29 million tons of coal reserves and approximately 56 million board feet of hardwood timber in western Virginia and eastern Kentucky. The purchase price was $24.5 million in cash and was funded with long-term debt under the Revolver.

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

In September 2007, we acquired fee ownership of approximately 62,000 acres of forestland in northern West Virginia. The purchase price was $93.3 million in cash and was funded with long-term debt under the Revolver.

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

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

Natural Gas Midstream Segment

In July 2008, we completed the Lone Star acquisition. 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 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.

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. The purchase price was $51.6 million in cash, after customary closing adjustments and was funded with long-term debt under the Revolver.

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

Liquidity and Capital Resources

Liquidity and Working Capital

Liquidity is defined as the ability to convert assets into cash or to obtain cash. Short-term liquidity refers to the ability to meet short-term obligations of 12 months or less. Liquidity is a matter of degree and is expressed in terms of working capital and the current ratio and, due to the recent deterioration of the credit and financial markets, in terms of the availability of borrowing capacity against existing credit facilities and debt instruments. Our consolidated working capital (current assets minus current liabilities) and consolidated current ratio (current assets divided by current liabilities) are as follows as of December 31, 2008 and 2007:

	As of December 31,	
	2008	2007
Current Assets	$ 117,445	$ 103,734
Current Liabilities	89,613	133,488
Working Capital	$ 27,832	$ (29,754)
Current Ratio	1.31	0.78

As discussed in more detail in "Long-Term Debt" below, as of December 31, 2008, we had availability of $130.3 million under our Revolver.

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 equity offerings. We fund 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 working capital requirements and anticipated capital expenditures (other than major capital improvements or acquisitions). We believe that the cash generated from our operations will be sufficient to meet our scheduled debt payments under the Revolver and distribution payments.

See Note 14 – "Partners' Capital and Distributions," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a tabular presentation of distribution thresholds.

Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry and natural gas midstream market, some of which are beyond our control. In addition, depending on the longevity and ultimate severity of the current deterioration of the global economy, including financial and credit markets, our ability to grow may be significantly adversely affected, as may our ability to make acquisitions and cash distributions to our limited partners and to PVG, the owner of our general partner. This is due to our debt capacity not being as readily expandable as in the past, which is driven by the overall restrictions on lending by the banking industry. Because of these restrictions to our debt capacity and deterioration in the financial and credit markets, we are anticipating a decrease in capital spending in 2009.

Cash Flows

The following table summarizes our cash flow statements for the years ended December 31, 2008, 2007 and 2006, consolidating our segments:

For the Year Ended December 31, 2008	Coal and Natural Resource Management	Natural Gas Midstream (in thousands)	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 59,192	$ 45,308	$ 104,500
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	41,463	(258)	41,205
Net change in operating assets and liabilities	(831)	(5,698)	(6,529)
Net cash provided by operating activities	$ 99,824	$ 39,352	139,176
Net cash used in investing activities	$ (25,272)	$ (305,758)	(331,030)
Net cash provided by financing activities			181,808
Net decrease in cash and cash equivalents			$ (10,046)

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

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

Net Cash Provided by Operating Activities

Changes to our working capital and to our current ratio are largely affected by net cash provided by operating activities. Net cash provided by operating activities primarily came from the following sources:

Coal and natural resource management segment:

- the collection of coal royalties;
- the sale of standing timber;
- the collection of coal transportation, or wheelage, fees;
- distributions received from our equity investees; and

- settlements from our interest rate swaps, or Interest Rate Swaps.

Natural gas midstream segment:

- the collection of revenues from natural gas processing contracts with natural gas producers;
- the collection of revenues from our natural gas marketing business; and
- settlements from our natural gas midstream commodity derivatives.

We use the cash provided by operating activities in the coal and natural resource management segment and the natural gas midstream segment in the following ways:

- operating expenses, such as core-hole drilling costs and repairs and maintenance costs;
- taxes other than income, such as severance and property taxes;
- general and administrative expenses, such as office rentals, staffing costs and legal fees;
- interest on debt service obligations;
- capital expenditures;
- repayments of borrowings; and
- distributions to our partners.

Net cash provided by operating activities in 2008 increased by $11.4 million, or 9%, to $139.2 million from $127.8 million in 2007. The overall increase in net cash provided by operating activities in 2008 compared to 2007 was primarily attributable to increased cash received from the sales of residue gas and NGLs, which was primarily driven by increased system throughput volume; increased coal royalties received, which was driven primarily by increased production and sales prices of coal in the Central Appalachian and Illinois Basin regions; and increased cash received from the sale of standing timber, which was due primarily to increased harvesting from our September 2007 forestland acquisition. These increases were partially offset by increased cash outflows from our natural gas midstream commodity derivative settlements.

Net cash provided by operating activities in 2007 increased by $20.5 million, or 19%, to $127.8 million from $107.3 million in 2006. This increase was primarily attributable to increased sales of NGLs, which was primarily driven by increased volumes of processed gas and a higher frac spread during 2007 than in 2006; and decreased cash outflows for our natural gas midstream commodity derivative settlements. These increases were partially offset by a decrease in coal royalties received, which was driven by a decrease in coal production from subleased properties in the Central Appalachian region.

Net Cash Used in Investing Activities

Net cash used in investing activities increased by $106.8 million, or 48%, from $224.2 million in 2007 to $331.0 million in 2008. The cash used in investing activities for the years ended December 31, 2008, 2007 and 2006 were used primarily for capital expenditures. The following table sets forth capital expenditures by segment made during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Coal and natural resource management			
Acquisitions (1)	$ 27,075	$ 176,918	$ 76,402
Expansion capital expenditures	-	85	15,103
Other property and equipment expenditures	195	84	100
Total	27,270	177,087	91,605
Natural gas midstream			
Acquisitions (2)	259,417	-	14,626
Expansion capital expenditures	59,385	38,686	15,394
Other property and equipment expenditures	14,505	9,767	9,414
Total	333,307	48,453	39,434
Total capital expenditures	$ 360,577	$ 225,540	$ 131,039

(1) Coal and natural resource management segment acquisitions in 2007 include an $11.5 million lease receivable associated with the acquisition of fee ownership and lease rights to coal reserves in western Kentucky and $31.0 million of oil and gas royalty interests that we purchased from Penn Virginia. Coal and natural resource management segment acquisitions in 2006 include the acquisition of assets and liabilities other than property or equipment of $1.2 million.

(2) Natural gas midstream segment acquisitions in 2008 include the following non-cash items, all of which was given as consideration in the Lone Star acquisition: newly issued PVR units valued at $15.2 million; PVG units, which were purchased from Penn Virginia, valued at $68.0 million; and a $4.7 million guaranteed payment which will be paid in 2009.

In 2008, we made aggregate capital expenditures of $360.6 million. These capital expenditures consisted primarily of discretionary capital expenditures which 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 million board feet 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.

In 2007, we made aggregate capital expenditures of $225.5 million. These capital expenditures consisted primarily of discretionary capital expenditures, which included our coal reserve acquisitions, a forestland acquisition, an oil and gas royalty interest acquisition and natural gas midstream gathering system expansion projects. Our natural gas midstream segment also incurred $9.8 million of maintenance capital expenditures for equipment overhauls and connecting wells in existing areas.

In 2006, we made aggregate capital expenditures of $131.0 million. These capital expenditures consisted primarily of discretionary capital expenditures, which included our coal reserve acquisitions, coal loadout facility construction projects, a natural gas midstream acquisition and coal and natural gas midstream gathering system expansion projects. Our natural gas midstream segment also incurred $9.4 million of maintenance capital expenditures for equipment overhauls and connecting wells in existing areas.

We funded our coal and natural resource management and natural gas midstream capital expenditures in 2008 primarily with cash provided by operating activities, borrowings under the Revolver, proceeds from the sale of common units and a contribution from our general partner in order to maintain its 2% general partner interest. We funded capital expenditures in 2007 with cash provided by operating activities and borrowings under the Revolver. We funded capital expenditures in 2006 with cash provided by operating activities, borrowings under the Revolver, proceeds from the sale of common and Class B units to PVG and a contribution from our general partner to maintain its 2% general partner interest. See "– Future Capital Needs and Commitments" for an analysis of future capital expenditures and the sources for funding those expenditures.

Net Cash Provided by Financing Activities

Net cash provided by financing activities increased by $77.4 million, or 74%, from $104.4 million in 2007 to $181.8 million in 2008. This increase was primarily due to net borrowings of $156.0 million in 2008, comprised of net borrowings of $220.4 million under the Revolver and net repayments of $64.4 million under the Senior Unsecured Notes due 2013, or the Notes. See "— Long-Term Debt" below for a more detailed description of our December 31, 2008 long-term debt balance. We also received net proceeds of $141.1 million from the sale of our common units in a public offering in 2008, 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. These increases in 2008 financing activities were partially offset by increased cash distributions paid to our partners. Cash distributions paid to partners increased by $21.5 million, or 24%, from $89.6 million in 2007 to $111.1 million in 2008 because we increased our cash distribution paid per unit. This increase in cash distributions to partners was also due to the increase in our outstanding common units resulting from our 2008 unit offering where we issued an additional 5.15 million common units to the public. See "– Unit Offering" below for a more detailed description of this event. We also incurred $4.2 million of payments for debt issuance costs. Net cash provided by financing activities in the year ended December 31, 2008 was used primarily for capital expenditures.

Our cash distributions per unit increased in every sequential quarter from the distribution paid in February 2007 for the fourth quarter of 2006 through the distribution paid in November 2008 for the third quarter of 2008. However, the most recent cash distribution paid to our partners in February 2009 for the fourth quarter of 2008 was unchanged from the distribution paid for the immediately prior quarter. We will continue to be cautious about increasing cash distributions to unitholders in the foreseeable future in order to preserve cash liquidity in light of uncertain commodity and financial markets.

Net cash provided by financing activities in 2007 increased by $93.9 million, or 887%, to $104.5 million from $10.6 million in 2006. This increase is due primarily to $193.5 million of net borrowings in 2007, comprised of net borrowings of $204.5 million under the Revolver and net repayments of $11.0 million under the Notes. These increases in 2007 financing activities were partially offset by $89.6 million in cash distributions paid to our partners. Distributions to partners increased by $22.6 million, or 34%, from $67.0 million in 2006 to $89.6 million in 2007 because we increased the cash distribution paid per unit. Net cash provided by financing activities in the year ended December 31, 2007 was used primarily for capital expenditures.

In December 2006, PVG completed its initial public offering and used substantially all of the resulting proceeds to purchase newly issued common and Class B units from us. We used the proceeds received from this transaction to repay $114.6 million of debt outstanding under the Revolver. We had a total of $37.1 million of net repayments of debt in 2006, comprised of $28.8 million of net repayments under the Revolver and $8.3 million of net repayments under the Notes. We also paid $67.0 million in cash distributions to our partners in 2006.

Long-Term Debt

Revolver. As of December 31, 2008, net of outstanding borrowings of $568.1 million and letters of credit of $1.6 million, we had remaining borrowing capacity of $130.3 million on the Revolver. In August 2008, we increased the size of our Revolver from $600.0 million to $700.0 million and secured the Revolver with substantially all of our assets. The Revolver matures in December 2011 and is available to us for general purposes, including working capital, capital expenditures and acquisitions, and includes a $10.0 million sublimit for the issuance of letters of credit. In 2008, we incurred commitment fees of $0.5 million on the unused portion of the Revolver. The interest rate under the Revolver fluctuates based on the ratio of our total indebtedness-to-EBITDA. Interest is payable at a base rate plus an applicable margin of up to 0.75% if we select the base rate borrowing option under the Revolver or at a rate derived from the London Interbank Offered Rate, or LIBOR, plus an applicable margin ranging from 0.75% to 1.75% if we select the LIBOR-based borrowing option. The weighted average interest rate on borrowings outstanding under the Revolver during 2008 was approximately 4.6%. We do not have a public credit rating for the Revolver.

The financial covenants under the Revolver require us not to exceed specified ratios. We are required to maintain a debt-to-consolidated EBITDA ratio of less than 5.25-to-1.0 and at December 31, 2008, such ratio was 4.05-to-1.0. We are also required to maintain a consolidated EBITDA-to-interest expense ratio of greater than 2.5-to-1.0 and at December 31, 2008, such ratio was 4.74-to-1.0. EBITDA, which is a non-GAAP measure, is generally defined in the Revolver as our net income before the effects of interest expense, interest income, DD&A expense and non-cash hedging activity. In the event that we would be in default of our covenants, we could appeal to the banks for a waiver of the covenant default. Should the banks deny our appeal to waive the covenant default, the outstanding borrowings under the Revolver would become payable upon demand and would be reclassified to the current liabilities section of our consolidated balance sheet. The Revolver contains cross-default provisions for default of indebtedness of more than $7.5 million. The Revolver does not contain a subjective acceleration clause. The Revolver prohibits us from making distributions to our partners if any potential default, or event of default, as defined in the Revolver, occurs or would result from the distributions. In addition, the Revolver contains various covenants that limit our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business or enter into a merger or sale of our assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2008, we were in compliance with all of our covenants under the Revolver.

Notes. In July 2008, we paid an aggregate of $63.3 million to the holders of the Notes to prepay 100% of the aggregate principal amount of the Notes. This amount consisted of approximately $58.4 million aggregate principal amount outstanding on the Notes, $1.1 million in accrued and unpaid interest on the Notes through the prepayment date and $3.8 million in make-whole amounts due in connection with the prepayment. The $3.8 million of make-whole payments were recorded in interest expense on our consolidated statements of income. The Notes were repaid with borrowings under the Revolver. While the Notes were outstanding, we had a DBRS public credit rating. However, due to the repayment of the Notes, we have elected not to renew this rating. As of December 31, 2007, we owed $64.0 million under the Notes, the current portion of which was $12.6 million. The Notes bore interest at a fixed rate of 6.02%.

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. Until March 2010, the notional amounts of the Interest Rate Swaps total $285.0 million, or approximately 50% of our total long-term debt outstanding as of December 31, 2008, with us paying a weighted average fixed rate of 3.67% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. From March 2010 to December 2011, the notional amounts of the Interest Rate Swaps total $225.0 million, with us paying a weighted average fixed rate of 3.52% 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 $75.0 million, with us paying a weighted average fixed rate of 2.10% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. The Interest Rate Swaps extend one year past the maturity of the current Revolver and they have been entered into with six financial institution counterparties, with no counterparty having more than 26% of the open positions. After considering the applicable margin of 1.75% in effect as of December 31, 2008, the total interest rate on the $285.0 million portion of Revolver borrowings covered by the Interest Rate Swaps was 5.42% at December 31, 2008. In January 2009, we entered into an additional $25.0 million interest rate swap with a maturity of December 2012. Inclusive of this additional interest rate swap, the weighted average fixed interest rate we pay to our counterparties is 3.54% through March 2010, 3.37% from March 2010 through December 2011 and 2.09% from December 2011 through December 2012.

We monitor changes in our counterparties and are not aware of any specific concerns regarding our counterparties' ability to make payments under any of the Interest Rate Swaps, including the January 2009 swap agreement.

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 2% general partner interest in us. The net proceeds were used to repay a portion of our borrowings under the Revolver.

Future Capital Needs and Commitments

We believe that our remaining borrowing capacity of $130.3 million will be sufficient for our 2009 capital needs and commitments. Our short-term cash requirements for operating expenses and quarterly distributions to PVG, as the owner of our general partner, and unitholders are expected to be funded through operating cash flows. In 2009, we anticipate making capital expenditures, excluding acquisitions, of up to $72.0 million. The majority of the 2009 capital expenditures will be incurred in the natural gas midstream segment. We intend to fund these capital expenditures with a combination of cash flows provided by operating activities and borrowings under the Revolver. Long-term cash requirements for acquisitions and other capital expenditures are expected to be funded by several sources, including cash flows from operating activities, borrowings under the Revolver and the issuances of additional debt and equity securities if available under commercially acceptable terms. Our short-term cash requirements for operating expenses and quarterly distributions to PVG, as the owner of our general partner, and unitholders are expected to be funded through operating cash flows.

Part of our long-term strategy is to increase cash available for distribution to our unitholders by making acquisitions and other capital expenditures. Our ability to make these acquisitions and other capital expenditures in the future will depend largely on the availability of debt financing and on our ability to periodically use equity financing through the issuance of new common units. Future financing will depend on various factors, including prevailing market conditions, interest rates and our financial condition and credit rating.

The current disruptions in the global financial and commodities markets and the general economic climate have made access to equity and debt capital markets very difficult since late in 2008. While signs of improvement in these markets have started to arise in 2009, with issuances of debt and equity securities by other publicly traded partnerships, the short-term outlook remains uncertain with respect to our ability to access the capital markets on acceptable terms. If the situation worsens and we are unable to access the capital markets for an extended period, our ability to make acquisitions and other capital expenditures, as well as our ability to increase or sustain cash distributions to our limited partners and to PVG, the owner of our general partner, will likely become limited. If additional financing is required, there are no assurances that it will be available, or if available, that it can be obtained on terms favorable to us or not dilutive to our future earnings.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2008:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 years
			(in thousands)		
Revolver	$ 568,100	$ -	$ 568,100	$ -	$ -
Asset retirement obligations (1)	1,814	-	-	369	1,445
Interest expense (2)	59,725	20,279	39,446	-	-
Derivatives (3)	20,500	13,585	6,915	-	-
Natural gas midstream activities (4)	36,793	13,069	11,862	8,541	3,321
Rental commitments (5)	14,684	2,678	3,571	2,628	5,807
Total contractual obligations (6)	$ 701,616	$ 49,611	$ 629,894	$ 11,538	$ 10,573

(1) The asset retirement obligations reflect the discounted balance, which is recorded in the other liabilities section of our consolidated balance sheets. See Note 12, "Asset Retirement Obligations," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data." The undiscounted balance was approximately $7.0 million at December 31, 2008.

(2) The interest expense commitments represent the estimated interest payments that will be due under the Revolver. See "– Long-Term Debt" for a detailed description of the Revolver and the factors affecting our interest expense calculation.

(3) The derivatives commitments represent the estimated payments we will make resulting from our commodity derivatives as well as the Interest Rate Swaps. See "– Long-Term Debt –Interest Rate Swaps" and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk – Price Risk" for a detailed description of our derivatives and Interest Rate Swaps.

(4) Commitments for natural gas midstream activities relate to firm transportation agreements. As of December 31, 2008, we had contracts for firm transportation capacity rights for specified volumes per day on a pipeline system with terms that ranged from one to seven years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

(5) Our rental commitments primarily relate to equipment and building leases and leases of coal reserve-based properties which we sublease, or intend to sublease, to third parties. The obligation with respect to leased properties which we sublease expires when the property has been mined to exhaustion or the lease has been canceled. The timing of mining by third party operators is difficult to estimate due to numerous factors. See Item 1A, "Risk Factors." We believe that the future rental commitments cannot be estimated with certainty; however, based on current knowledge and historical trends, we believe that we will incur between approximately $0.9 million and $1.0 million in rental commitments annually until the reserves have been exhausted.

(6) Total contractual obligations do not include reimbursements to Penn Virginia. Penn Virginia is entitled to receive reimbursements of direct and indirect expenses incurred on our behalf until we are dissolved. Total contractual obligations also do not include $72.0 million of anticipated 2009 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 did not accrue these contingent payments as a liability during the year ended December 31, 2008. Rather, once the revenue targets are met, the contingent payments will be recorded as an additional cost of Lone Star.

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

Off-Balance Sheet Arrangements

As of December 31, 2008, we did not have any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We are, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships.

Results of Operations

Selected Financial Data—Consolidated

The following table sets forth a summary of certain consolidated financial data for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands, except per unit data)		
Revenues	$ 881,580	$ 549,445	$ 517,891
Expenses	$ 766,338	$ 431,720	$ 415,071
Operating income	$ 115,242	$ 117,725	$ 102,820
Net income	$ 104,500	$ 56,623	$ 73,928
Net income per limited partner unit, basic and diluted	$ 1.67	$ 0.96	$ 1.56
Cash flows provided by operating activities	$ 139,176	$ 127,824	$ 107,344

Operating income decreased in 2008 compared to 2007 primarily due to a $31.8 million charge for goodwill impairment in 2008 and a $16.7 million increase in DD&A expenses, partially offset by a $17.6 million increase in our gross margin and a $28.7 million increase in coal royalties revenues. Operating income increased in 2007 compared to 2006 primarily due to a $21.8 million increase in natural gas midstream gross margin, a $1.4 million increase in coal services revenues and a $0.9 million increase in oil and gas royalties, partially offset by a $4.1 million decrease in coal royalties revenues, a $4.0 million increase in DD&A expenses and a $2.3 million increase in general and administrative expenses.

Net income increased in 2008 compared to 2007 primarily due to the $62.4 million increase in derivative income resulting from changes in the valuation of unrealized derivative positions, partially offset by the decrease in operating income and a $7.3 million increase in interest expense. Net income decreased in 2007 compared to 2006 primarily due to a $34.3 million increase in derivative losses, partially offset by the increase in operating income and a $1.5 million decrease in interest expense.

Coal and Natural Resource Management Segment

Year Ended December 31, 2008 Compared With Year Ended December 31, 2007

The following table sets forth a summary of certain financial and other data for our coal and natural resource management segment and the percentage change for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Coal royalties	$ 122,834	$ 94,140	30%
Coal services	7,355	7,252	1%
Timber	6,943	1,711	306%
Oil and gas royalty	5,989	1,864	221%
Other	10,206	6,672	53%
Total revenues	153,327	111,639	37%
Expenses			
Coal royalties expense	9,534	5,540	72%
Other operating	2,406	2,531	(5%)
Taxes other than income	1,680	1,110	51%
General and administrative	12,606	10,957	15%
Depreciation, depletion and amortization	30,805	22,690	36%
Total expenses	57,031	42,828	33%
Operating income	$ 96,296	$ 68,811	40%
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	33,690	32,528	4%
Average royalties revenues per ton ($/ton)	$ 3.65	$ 2.89	26%
Less royalties expense per ton ($/ton)	(0.28)	(0.17)	65%
Average net coal royalties per ton ($/ton)	$ 3.37	$ 2.72	24%

Revenues. Coal royalties revenues increased by $28.7 million, or 30%, from $94.1 million in 2007 to $122.8 million in 2008 primarily due to increased production in the Central Appalachian and Illinois Basin regions and increased sales prices in those regions. Coal royalties expense increased by $4.0 million, or 72%, from $5.5 million in 2007 to $9.5 million in 2008, primarily due to the increase in production on our subleased property in the Central Appalachian region and is due to higher average sales prices for coal in the Central Appalachian region. The average net coal royalty per ton, which represents the average coal royalties revenue per ton, net of coal royalties expense, increased by $0.65 per ton, or 24%, from $2.72 per ton in 2007 to $3.37 per ton in 2008. The increase in average net coal royalty per ton was due primarily to the higher royalty revenues per ton received by our lessees in the region. The increase in royalty revenues per ton received in Central Appalachia was due primarily to both increased coal production and higher average sales prices for coal in that region.

The following table summarizes coal production, coal royalties revenues and coal royalties per ton by region for the years ended December 31, 2008 and 2007:

	Coal Production		Coal Royalties Revenues		Coal Royalties Per Ton	
	Year Ended December 31,		Year Ended December 31,		Year Ended December 31,	
Region	2008	2007	2008	2007	2008	2007
	(tons in thousands)		(in thousands)		($/ton)	
Central Appalachia	19,587	18,827	$ 93,577	$ 68,815	$ 4.78	$ 3.66
Northern Appalachia	3,578	4,194	6,568	6,434	1.84	1.53
Illinois Basin	4,584	3,779	10,451	7,432	2.28	1.97
San Juan Basin	5,941	5,728	12,238	11,459	2.06	2.00
Total	33,690	32,528	$ 122,834	$ 94,140	$ 3.65	$ 2.89
Less coal royalties expense (1)			(9,534)	(5,540)	(0.28)	(0.17)
Net coal royalties revenues			$ 113,300	$ 88,600	$ 3.37	$ 2.72

(1) Our coal royalties expense is incurred primarily in the Central Appalachian region.

Coal production in the Central Appalachian region increased by 0.8 million tons, or 4%, from 18.8 million tons in 2007 to 19.6 million tons in 2008. This increase was due primarily to longwall mining and the timing of mining equipment added to our properties in that region during 2008. Coal production in the Northern Appalachian region decreased by 0.6 million tons, or 15%, from 4.2 million tons in 2007 to 3.6 million tons in 2008. This decrease was due primarily to adverse longwall mining conditions. Coal production in the Illinois Basin region increased by 0.8 million tons, or 21%, from 3.8 million tons in 2007 to 4.6 million tons in 2008. This increase was due primarily to a full year of production in 2008 on the coal reserves that were acquired in June 2007. Coal production in the San Juan Basin region remained relatively constant from 2007 to 2008.

Coal services revenues remained relatively constant from 2007 to 2008. Timber revenues increased by $5.2 million, or 306%, from $1.7 million in 2007 to $6.9 million in 2008 primarily due to increased harvesting from our September 2007 forestland acquisition. Oil and gas royalty revenues increased by $4.1 million, or 221%, from $1.9 million in 2007 to $6.0 million in 2008, primarily due to the increased royalties resulting from our October 2007 oil and gas royalty interest acquisition. Other revenues increased by $3.5 million, or 53%, from $6.7 million in 2007 to $10.2 million in 2008, primarily due to increased coal transportation, or wheelage, fees attributable to better longwall production and an increase in sales prices in 2008, increased forfeiture income and a $0.8 million gain on the settlement of sterilized coal.

Expenses. Other operating expenses remained relatively constant from 2007 to 2008. Taxes other than income increased by $0.6 million, or 51%, from $1.1 million in 2007 to $1.7 million in 2008, primarily due to increased severance taxes resulting from our September 2007 forestland acquisition and October 2007 oil and gas royalty interest acquisition. General and administrative expenses increased by $1.6 million, or 15%, from $11.0 million in 2007 to $12.6 million in 2008, primarily due to increased staffing costs. DD&A expenses increased by $8.1 million, or 36%, from $22.7 million in 2007 to $30.8 million in 2008 primarily due to increased depletion resulting from our September 2007 forestland acquisition, October 2007 oil and gas royalty interest acquisition and May 2008 coal reserves and forestland acquisition.

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

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

	Year Ended December 31, 2007	Year Ended December 31, 2006	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Coal royalties	$ 94,140	$ 98,163	(4%)
Coal services	7,252	5,864	24%
Timber	1,711	1,024	67%
Oil and gas royalty	1,864	957	95%
Other	6,672	6,973	(4%)
Total revenues	111,639	112,981	(1%)
Expenses			
Coal royalties	5,540	6,927	(20%)
Other operating	2,531	1,673	51%
Taxes other than income	1,110	934	19%
General and administrative	10,957	9,604	14%
Depreciation, depletion and amortization	22,690	20,399	11%
Total expenses	42,828	39,537	8%
Operating income	$ 68,811	$ 73,444	(6%)
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	32,528	32,778	(1%)
Average royalties revenues per ton ($/ton)	$ 2.89	$ 2.99	(3%)
Less royalties expense per ton ($/ton)	$ (0.17)	$ (0.21)	(19%)
Average net coal royalties per ton ($/ton)	$ 2.72	$ 2.78	(2%)

Revenues. Coal royalties revenues decreased by $4.1 million, or 4%, from $98.2 million in 2006 to $94.1 million in 2007, primarily due to a lower average royalty per ton. Coal royalties expense decreased by $1.4 million, or 20%, from $6.9 million in 2006 to $5.5 million in 2007 primarily due to a decrease in production from subleased properties in the Central Appalachian region. The average net coal royalty per ton, which represents the average coal royalties revenue per ton, net of coal royalties expense, remained relatively constant from 2006 to 2007.

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

	Coal Production		Coal Royalties Revenues		Coal Royalties Per Ton	
	Year Ended December 31,		Year Ended December 31,		Year Ended December 31,	
Region	2007	2006	2007	2006	2007	2006
	(tons in thousands)		(in thousands)		($/ton)	
Central Appalachia	18,827	20,156	$ 68,815	$ 76,542	$ 3.66	$ 3.80
Northern Appalachia	4,194	5,009	6,434	7,314	1.53	1.46
Illinois Basin	3,779	2,540	7,432	4,768	1.97	1.88
San Juan Basin	5,728	5,073	11,459	9,539	2.00	1.88
Total	32,528	32,778	$ 94,140	$ 98,163	$ 2.89	$ 2.99
Less coal royalties expense (1)			(5,540)	(6,927)	(0.17)	(0.21)
Net coal royalties revenues			$ 88,600	$ 91,236	$ 2.72	$ 2.78

(1) Our coal royalties expense is incurred primarily in the Central Appalachian region.

Coal production in the Central Appalachian region decreased by 1.4 million tons, or 7%, from 20.2 million tons in 2006 to 18.8 million tons in 2007. This decrease was due primarily to delays in the move of the longwall due to adverse mining conditions, the closing of certain mines in 2006 in the Central Appalachian region and permitting issues in the Central Appalachian region involving properties on which our coal reserves are located. Coal production in the Northern Appalachian region decreased by 0.8 million tons, or 16%, from 5.0 million tons in 2006 to 4.2 million tons in 2007. This decrease was due primarily to delays in the move of the longwall due to development delays, as well as the depletion of reserves in one mine. Coal production in the Illinois Basin region increased by 1.3 million tons, or 49%, from 2.5 million tons in 2006 to 3.8 million tons in 2007. This increase was due primarily to the June 2007 acquisition of coal reserves in Western and Hopkins Counties, Kentucky. Coal production in the San Juan Basin region increased by 0.6 million tons, or 13%, from 5.1 million tons in 2006 to 5.7 million tons in 2007. This increase was due primarily to an increase in spot market orders of coal due to the depletion of adjacent reserves not owned by us.

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

Expenses. Other operating expenses increased by $0.8 million, or 51%, from $1.7 million in 2006 to $2.5 million in 2007 primarily due to an increase in mine maintenance and core-hole drilling expenses on the Central Appalachian and Illinois Basin properties. General and administrative expenses increased by $1.4 million, or 14%, from $9.6 million in 2006 to $11.0 million in 2007 primarily due to increased staffing costs. DD&A expenses increased by $2.3 million, or 11%, from $20.4 million in 2006 to $22.7 million in 2007 primarily due to increased depletion resulting from the September 2007 forestland acquisition and October 2007 oil and gas royalty interest acquisition. In addition, we began depreciating our coal services facility in Knott County, Kentucky, which began operations in October 2006.

Natural Gas Midstream Segment

Year Ended December 31, 2008 Compared With Year Ended December 31, 2007

The following table sets forth a summary of certain financial and other data for our natural gas midstream segment and the percentage change for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Residue gas	$ 452,535	$ 242,129	87%
Natural gas liquids	229,765	172,144	33%
Condensate	26,009	13,889	87%
Gathering, processing and transportation fees	11,693	5,012	133%
Total natural gas midstream revenues (1)	720,002	433,174	66%
Equity earnings in equity investment	2,408	-	-
Producer services	5,843	4,632	26%
Total revenues	728,253	437,806	66%
Expenses			
Cost of midstream gas purchased (1)	612,530	343,293	78%
Operating	20,737	12,893	61%
Taxes other than income	2,578	1,926	34%
General and administrative	14,300	11,958	20%
Impairments	31,801	-	-
Depreciation and amortization	27,361	18,822	45%
Total operating expenses	709,307	388,892	82%
Operating income	$ 18,946	$ 48,914	(61%)
Operating Statistics			
System throughput volumes (MMcf)	98,683	67,810	46%
System throughput volumes (MMcfd)	270	186	45%
Gross margin	$ 107,472	$ 89,881	20%
Impact of derivatives	(31,709)	(13,184)	141%
Gross margin, adjusted for impact of derivatives	$ 75,763	$ 76,697	(1%)
Gross margin ($/Mcf)	$ 1.09	$ 1.33	(18%)
Impact of derivatives ($/Mcf)	(0.32)	(0.19)	68%
Gross margin, adjusted for impact of derivatives ($/Mcf)	$ 0.77	$ 1.14	(32%)

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(1) In 2008, we recorded $127.9 million of natural gas midstream revenue 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. 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. Cost of midstream gas purchased consisted of amounts payable to third-party producers for natural gas purchased under percentage-of-proceeds and gas purchase/keep-whole contracts.

Natural gas midstream revenues increased by $286.8 million, or 66%, from $433.2 million in 2007 to $720.0 million in 2008. Cost of midstream gas purchased increased by $269.2 million, or 78%, from $343.3 million in 2007 to $612.5 million in 2008. The gross margin increased by $17.6 million, or 20%, from $89.9 million in 2007 to $107.5 million in 2008. The gross margin increase was a result of increased commodity pricing, increased system throughput volume production and higher fractionation, or frac spreads, during 2008 compared to 2007. Frac spreads are the difference between the price of NGLs sold and the cost of natural gas purchased on a per MMBtu basis.

System throughput volumes increased by 84 MMcfd, or 45%, from 186 MMcfd in 2007 to 270 MMcfd in 2008. This increase in throughput volumes is due primarily to the Crossroads plant in East Texas, which became fully operational in 2008, and to the Lone Star acquisition, which was consummated in the third quarter of 2008. Also, the continued successful development by producers operating in the vicinity of the Panhandle System, as well as our success in contracting and connecting new supply contributed to the increase in throughput volume.

In 2008, our two expansion projects related to natural gas processing facilities became operational. These two natural gas processing facilities consisted of the Spearman plant in the Texas Panhandle, which was placed into service in February 2008 and has approximately 60 MMcfd capacity and the Crossroads plant in East Texas, which was placed into service in April 2008 and has approximately 80 MMcfd capacity. The Crossroads plant will process most of the Cotton Valley gas production for Penn Virginia as well as other producers, and the Spearman plant will process gas that had previously bypassed the Beaver plant.

During 2008, 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, "Derivative Instruments," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a description of our derivatives program. Adjusted for the impact of our commodity derivative instruments for which we discontinued hedge accounting in 2006, our gross margin remained relatively constant from 2007 to 2008. On a per Mcf basis, the gross margin, adjusted for the impact of our commodity derivative instruments for which we discontinued hedge accounting in 2006, decreased by $0.37, or 32%, from $1.14 per Mcf in 2007 to $0.77 in 2008. Gross margins during the first part of 2008 continued to increase given the favorable pricing environment, such as higher commodity prices and frac spreads, and increased system throughput volumes. However, margins decreased towards the end of the year due to a significant decrease in the prices of NGLs as a result of reduced industrial demand in a weakening economy. The gross margin on a Mcf basis decreased in 2008 due to an increase in fee-based system throughput volumes. These volumes are associated with the expansions and acquisitions made during 2008.

Producer Services Revenues. Producer services revenues increased by $1.2 million, or 26%, from $4.6 million in 2007 to $5.8 million in 2008 primarily due to an increase in agent fees for the marketing of Penn Virginia's and third parties' natural gas production. Agent fees increased primarily due to increases in Penn Virginia's natural gas production as well as increases in the price of natural gas.

Equity Earnings in Equity Investment. This increase is due to our 25% member interest in Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. We acquired this member interest in April 2008.

Expenses. Total operating costs and expenses increased primarily due to increases in operating expenses, taxes other than income, general and administrative expenses, a $31.8 million loss on the impairment of goodwill and depreciation and amortization.

Operating expenses increased by $7.8 million, or 61%, from $12.9 million in 2007 to $20.7 million in 2008, primarily due to expenses related to our expanding footprint in areas of operation, including acquisitions and the addition of the Spearman and Crossroads plants. These expenses include increased repairs and maintenance expenses, increased compressor rentals, chemical and treating expenses and increased employee expenses. General and administrative expenses increased by $2.3 million, or 20%, from $12.0 million in 2007 to $14.3 million in 2008 primarily due to increased staffing costs. Taxes other than income increased by $0.7 million, or 34%, from $1.9 million in 2007 to $2.6 million in 2008. Depreciation and amortization expenses increased by $8.6 million, or 45%, from $18.8 million in 2007 to $27.4 million in 2008. Increases in both taxes other than income and depreciation and amortization expenses were primarily due to capital spending on the Spearman and Crossroads plants and acquisitions, including increased payroll taxes resulting from increased staffing.

In accordance with Statement of Financial Accounting Standards, or SFAS, No. 142, *Goodwill and Other Intangible Assets*, 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, reduces to zero all goodwill recorded in conjunction with acquisitions made by our 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%. See Note 9, "Goodwill," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a further description of the impairment of goodwill.

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

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

	Year Ended December 31,		%
	2007	2006	Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Residue gas	$ 242,129	$ 259,764	(7%)
Natural gas liquids	172,144	130,675	32%
Condensate	13,889	9,989	39%
Gathering and transportation fees	5,012	2,287	119%
Total natural gas midstream revenues	433,174	402,715	8%
Producer services	4,632	2,195	111%
Total revenues	437,806	404,910	8%
Expenses			
Cost of midstream gas purchased	343,293	334,594	3%
Operating	12,893	11,403	13%
Taxes other than income	1,926	1,420	36%
General and administrative	11,958	11,023	8%
Depreciation and amortization	18,822	17,094	10%
Total operating expenses	388,892	375,534	4%
Operating income	$ 48,914	$ 29,376	67%
Operating Statistics			
System throughput volumes (MMcf)	67,810	61,995	9%
System throughput volumes (MMcfd)	186	170	9%
Gross margin	$ 89,881	$ 68,121	32%
Impact of derivatives	(13,184)	(17,483)	(25%)
Gross margin, adjusted for impact of derivatives	$ 76,697	$ 50,638	51%
Gross margin ($/Mcf)	$ 1.33	$ 1.10	21%
Impact of derivatives ($/Mcf)	(0.19)	(0.28)	(32%)
Gross margin, adjusted for impact of derivatives ($/Mcf)	$ 1.14	$ 0.82	39%

Gross Margin. Natural gas midstream revenues increased by $30.5 million, or 8%, from $402.7 million in 2006 to $433.2 million in 2007. Cost of midstream gas purchased increased by $8.7 million, or 3%, from $334.6 million in 2006 to $343.3 million in 2007. Our gross margin increased by $21.8 million, or 32%, from $68.1 million in 2006 to $89.9 million in 2007. The gross margin increase was a result of a higher frac spread during 2007 and higher volumes of processed gas.

System throughput volumes at our gas processing plants and gathering systems increased by 16 MMcfd, or 9%, from 170 MMcfd in 2006 to 186 MMcfd in 2007. This increase is the result of higher volumes of processed gas, which is the portion of the system throughput volumes that is actually processed at the processing facility. The increase in processed gas was attributable to our success in contracting and connecting new supply to our facilities. Much of this new gas was a result of continued successful development by the producers operating in the vicinity of our systems. Additionally, the pipeline we acquired in 2006 allowed us to connect a number of our gathering systems directly to our Beaver plant, bringing its utilization of processing capacity to 100%.

During 2007, we generated a majority of our gross margin from contractual arrangements under which 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 a 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, "Derivative Instruments," in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a description of our derivative program. Adjusted for the impact of our commodity derivative instruments for which we discontinued hedge accounting in 2006, our gross margin increased by $26.1 million, or 51%, from $50.6 million in 2006 to $76.7 million in 2007. On a per Mcf basis, the gross margin, adjusted for the impact of our commodity derivative instruments for which we discontinued hedge accounting in 2006, increased by $0.32, or 39%, from $0.82 per Mcf in 2006 to $1.14 in 2007.

Producer Services Revenues. Producer services revenues increased by $2.4 million, or 111%, from $2.2 million in 2006 to $4.6 million in 2007 primarily due to an increase in agent fees for the marketing of Penn Virginia's and third parties' natural gas production. Agent fees increased primarily due to increases in Penn Virginia's natural gas production as well as increases in the price of natural gas.

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

Operating expenses increased by $1.5 million, or 13%, from $11.4 million in 2006 to $12.9 million in 2007 primarily due to a full year of operations in 2007 on the pipeline and related compression facilities in Texas and Oklahoma that we acquired in 2006 and increased fees from compressor rentals. General and administrative expenses increased by $1.0 million, or 8%, from $11.0 million in 2006 to $12.0 million in 2007 primarily due to increased staffing costs. Taxes other than income increased by $0.5 million, or 36%, from $1.4 million in 2006 to $1.9 million in 2007. Depreciation and amortization expenses increased by $1.7 million, or 10%, from $17.1 million in 2006 to $18.8 million in 2007. Increases in both taxes other than income and depreciation and amortization expenses were primarily due to capital spending on organic growth and acquisition opportunities occurring in both 2006 and 2007.

Other

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

Interest Expense. Our consolidated interest expense increased by $7.4 million, or 42%, from $17.3 million in the year ended December 31, 2007 to $24.7 million in the same period of 2008. Our consolidated interest expense decreased by $1.5 million, or 8%, from $18.8 million in the year ended December 31, 2006 to $17.3 million in the same of 2007. Our consolidated interest expense for the years ended December 31, 2008, 2007 and 2006 is comprised of the following:

	Year Ended December 31,		
Source	**2008**	**2007**	**2006**
		(in thousands)	
Borrowings	$ (23,641)	$ (18,861)	$ (19,661)
Capitalized interest	675	786	335
Interest rate swaps	(1,706)	737	505
Total interest expense	$ (24,672)	$ (17,338)	$ (18,821)

The increase in interest expense in 2008 compared to 2007 is primarily due to the increase in our average debt balance, which increased from $289.3 million in 2007 to $478.5 million in 2008. The decrease in interest expense in 2007 compared to 2006 is primarily due to a $114.6 million principal payment made by us on the Revolver in December 2006.

We capitalized $0.7 million and $0.8 million in interest costs in 2008 and 2007 primarily related to the construction of the Spearman and Crossroads plants and $0.3 million in 2006 related to the construction of a coal services facility in October 2006. In connection with periodic settlements, we recognized $1.7 million in net hedging losses on the Interest Rate Swaps in interest expense in 2008. In connection with periodic settlements, we recognized $0.7 million and $0.5 million in net hedging gains on the Interest Rate Swaps in interest expense in 2007 and 2006.

Derivatives. Our results of operations and operating cash flows were impacted by changes in market prices for NGLs, crude oil and natural gas prices. 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 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 derivatives in a liability position, in accordance with SFAS No. 157.

In 2008, derivative gains were $16.8 million for changes in fair value and cash paid for settlements totaled $38.5 million. In 2007, derivative expenses were $45.6 million for changes in fair value and cash paid for settlements totaled $17.8 million. In 2006, derivative expenses were $11.3 million for changes in fair value, and cash paid for settlements totaled $19.4 million.

Our derivative activity for the years ended December 31, 2008, 2007 and 2006 is summarized below:

	Year Ended December 31,		
	2008	**2007**	**2006**
		(in thousands)	
Natural gas midstream segment unrealized derivative gain (loss)	$ 55,303	$ (27,789)	$ 8,176
Natural gas midstream segment realized loss	(38,466)	(17,779)	(19,436)
Total derivative gain (loss)	$ 16,837	$ (45,568)	$(11,260)

Summary of Critical Accounting Policies and Estimates

The process of preparing financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We consider the following to be the most critical accounting policies which involve the judgment of our management.

Coal Royalties Revenues

We recognize coal royalties revenues on the basis of tons of coal sold by our lessees and the corresponding revenues from those sales. Since we do not operate any coal mines, we do not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. We record any differences, which 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.

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 three-way collars. All derivative financial instruments are recognized in our consolidated financial statements at fair value in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. The fair values of our derivative instruments are determined based on 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.

Until April 30, 2006, we applied hedge accounting for commodity derivative financial instruments as allowed under SFAS No. 133. Our commodity derivative financial instruments initially qualified as cash flow hedges, and changes in fair value of the effective portion of these contracts were deferred in accumulated other comprehensive income until the hedged transactions settled. When we discontinued hedge accounting for commodity derivatives, a net loss remained in accumulated other comprehensive income of $12.1 million. As the hedged transactions settled in 2006, 2007 and 2008, we recognized the $12.1 million of deferred changes in fair value in revenues and cost of gas purchased in our consolidated statements of income related to commodity derivatives. As of December 31, 2008, all amounts deferred under previous commodity hedging relationships have been reclassified into revenues and cost of midstream gas purchased.

We continue to apply hedge accounting to some of the interest rate swap agreements, or the Interest Rate Swaps. Settlements on the Interest Rate Swaps that follow hedge accounting are recorded as interest expense. The effective portion of the change in the fair value of the swaps that follow hedge accounting is recorded each period in accumulated other comprehensive income. Certain of the Interest Rate Swaps do not follow hedge accounting. Accordingly, mark-to-market gains and losses for the Interest Rate Swaps that do not follow hedge accounting are recognized in earnings currently in the derivatives line on the consolidated statements of income. Our results of operations are affected by the changes in fair value, which fluctuates with changes in interest rates.

Because we no longer apply 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. See Note 6 – "Derivative Instruments" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a further description of our derivatives program.

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 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 sheets. 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 on sales of property and equipment.

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 under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. See Note 10, "Intangible Assets, net" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a more detailed description of our intangible assets.

Impairment of Goodwill

Goodwill has been allocated to our natural gas midstream segment. Under SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill recorded in connection with acquisitions and business combinations 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 an asset for possible impairment. Indicators such as significant decreases in a reporting unit's book value, cash flows which cannot be resolved or improved within a reasonable amount of time, sustained operating losses, 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 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, reduces 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 is 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. Our goodwill balance at December 31, 2007 was $7.7 million. See Note 9 – "Goodwill" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a description of goodwill and the related impairment charge.

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, 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 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.

Fair Value Measurements

We adopted SFAS No. 157, *Fair Value Measurements*, effective January 1, 2008, for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. The Financial Accounting Standards Board, or FASB, Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157*, delays the application of SFAS No. 157 for nonfinancial assets and nonfinancial liabilities to fiscal years and interim periods beginning after November 15, 2008.

SFAS No. 157 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).

We use the following methods and assumptions to estimate the fair values of financial instruments:

- Commodity derivative instruments: Our natural gas midstream segment's commodity derivatives utilize three-way collar derivative contracts. We also utilize collar derivative contracts to hedge against the variability in the frac spread. We determine the fair values 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 derivatives in a liability position, in accordance with SFAS No. 157. This is a level 2 input. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. See Note 6 – "Derivative Instruments" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data."
- 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. This is a level 2 input. See Note 6 – "Derivative Instruments" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data."

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, 2008 and 2007, our environmental liabilities included $1.2 million and $1.5 million, which represents our best estimate of the liabilities as of those dates related to our coal and natural resource management and natural gas midstream businesses. We have reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future. For a summary of the environmental laws and regulations applicable to our operations, see Item 1, "Business—Government Regulation and Environmental Matters."

Recent Accounting Pronouncements

See Note 2 – "Summary of Significant Accounting Policies" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a description of recent accounting pronouncements.

Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the risks set forth in Item 1A, "Risk Factors."

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

Item 7A *Quantitative and Qualitative Disclosures About Market Risk*

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are 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 recent deterioration of the global economy, including financial and credit markets. At December 31, 2008, we reported a net commodity derivative asset related to the natural gas midstream segment of $22.7 million that is with two counterparties and is substantially concentrated with one 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.

We have completed a number of acquisitions in recent years. See Note 3, "Acquisitions" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a description of the 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 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 record a significant impairment charge 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.

In 2008, we reported net derivative gains of $16.8 million. Until April 30, 2006, we applied hedge accounting for commodity derivative financial instruments as allowed under SFAS No. 133. 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, a net loss of $12.1 million remained in accumulated other comprehensive income. As the hedged transactions settled in 2006, 2007 and 2008, we recognized the $12.1 million 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 open mark-to-market commodity derivative agreements and their fair values as of December 31, 2008:

		Weighted Average Price			
	Average Volume Per Day	Additional Put Option	Floor	Ceiling	Fair Value (in thousands)
Crude Oil Three-way Collar	(in barrels)		(per barrel)		
First Quarter 2009 through Fourth Quarter 2009	1,000	$ 70.00	$ 90.00	$ 119.25	$ 6,101
Frac Spread Collar	(in MMBtu)		(per MMBtu)		
First Quarter 2009 through Fourth Quarter 2009	6,000		$ 9.09	$ 13.94	14,943
Settlements to be received in subsequent month					1,694
Natural gas midstream segment commodity derivatives - net asset					$ 22,738

We estimate that, excluding the derivative positions described above, for every $1.00 per MMBtu increase or decrease in the natural gas price, natural gas midstream gross margin and operating income in 2009 would decrease or increase by approximately $4.7 million. In addition, we estimate that for every $5.00 per barrel increase or decrease in the crude oil price, natural gas midstream gross margin and operating income in 2009 would increase or decrease by approximately $4.6 million. This assumes that crude oil prices, natural gas prices and inlet volumes remain constant at anticipated levels. These estimated changes in gross margin and operating income exclude potential cash receipts or payments in settling these derivative positions.

We estimate that for a $5.00 per barrel increase in the crude oil price, the fair value of the crude oil three-way collar would decrease by $0.5 million. We estimate that for a $5.00 per barrel decrease in the crude oil price, the fair value of the crude oil three-way collar would increase by $0.4 million. In addition, we estimate that a $1.00 per MMBtu increase or decrease in the natural gas purchase price and a $4.65 per barrel (the estimated equivalent of $5.00 per barrel of crude oil) increase or decrease in the NGL sales price would affect the fair value of the frac spread collar by $0.3 million. These estimated changes exclude potential cash receipts or payments in settling these derivative positions.

Interest Rate Risk

As of December 31, 2008, we had $568.1 million of outstanding indebtedness under the Revolver, which carries a variable interest rate throughout its term. We entered into the Interest Rate Swaps to effectively convert the interest rate on $285.0 million of the amount outstanding under the Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 3.67% plus the applicable margin until March 2010. From March 2010 to December 2011, the notional amounts of the Interest Rate Swaps total $225.0 million with us paying a weighted average fixed rate of 3.52% 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 $75.0 million, with us paying a weighted average fixed rate of 2.10% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. The Interest Rate Swaps extend one year past the maturity of the current Revolver. A 1% increase in short-term interest rates on the floating rate debt outstanding under the Revolver (net of amounts fixed through hedging transactions) as of December 31, 2008 would cost us approximately $2.8 million in additional interest expense.

We continue to apply hedge accounting to some of the Interest Rate Swaps. Settlements on our Interest Rate Swaps that follow hedge accounting are recorded as interest expense. Accordingly, the effective portion of the change in the fair value of the swaps that follow hedge accounting is recorded each period in accumulated other comprehensive income. Certain of our Interest Rate Swaps do not follow hedge accounting. Accordingly, mark-to-market gains and losses for our Interest Rate Swaps that do not follow hedge accounting are recognized in earnings currently on the derivatives line on our consolidated statements of income. 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 – "Derivative Instruments" in the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data," for a further description of our derivatives program.

Customer Credit Risk

We are exposed to the credit risk of our customers and lessees. Approximately 79%, or $58.1 million, of our consolidated accounts receivable at December 31, 2008 resulted from our natural gas midstream segment and approximately 21%, or $15.2 million, resulted from our coal and natural resource management segment. Approximately $26.8 million of the natural gas midstream segment's receivables at December 31, 2008 were related to three customers: Tenaska Marketing Ventures, Conoco, Inc. and Louis Dreyfus Energy Services. At December 31, 2008, 46% of our natural gas midstream segment accounts receivable and 37% of our consolidated accounts receivable related to these three natural gas midstream customers. No significant uncertainties related to the collectability of amounts owed to us exist in regards to these three natural gas midstream customers.

This customer concentration increases our exposure to credit risk on our receivables, since the financial insolvency of any 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, 2008, no receivables were collateralized, and we had recorded a $1.4 million allowance for doubtful accounts in the natural gas midstream segment.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Penn Virginia Resource Partners, L.P., a Delaware limited partnership, and subsidiaries as of December 31, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, 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, 2008, 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 27, 2009, expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 27, 2009

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, 2008, 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, 2008, 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. as of December 31, 2008 and 2007, 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, 2008, and our report dated February 27, 2009, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 27, 2009

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

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

	Year Ended December 31,		
	2008	**2007**	**2006**
Revenues			
Natural gas midstream	$ 720,002	$ 433,174	$ 402,715
Coal royalties	122,834	94,140	98,163
Coal services	7,355	7,252	5,864
Other	31,389	14,879	11,149
Total revenues	881,580	549,445	517,891
Expenses			
Cost of midstream gas purchased	612,530	343,293	334,594
Operating	32,677	20,964	20,003
Taxes other than income	4,258	3,036	2,354
General and administrative	26,906	22,915	20,627
Impairments	31,801	-	-
Depreciation, depletion and amortization	58,166	41,512	37,493
Total expenses	766,338	431,720	415,071
Operating income	115,242	117,725	102,820
Other income (expense)			
Interest expense	(24,672)	(17,338)	(18,821)
Other	(2,907)	1,804	1,189
Derivatives	16,837	(45,568)	(11,260)
Net income	$ 104,500	$ 56,623	$ 73,928
General partner's interest in net income	$ 21,738	$ 12,452	$ 8,321
Limited partners' interest in net income	$ 82,762	$ 44,171	$ 65,607
Basic and diluted net income per limited partner unit (see Note 2)	$ 1.67	$ 0.96	$ 1.56
Weighted average number of units outstanding, basic and diluted	49,495	46,103	42,014

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands, except unit amounts)

	As of December 31, 2008	As of December 31, 2007
Assets		
Current assets		
Cash and cash equivalents	$ 9,484	$ 19,530
Accounts receivable, net of allowance for doubtful accounts	73,267	78,888
Derivative assets	30,431	1,212
Other current assets	4,263	4,104
Total current assets	117,445	103,734
Property, plant and equipment	1,093,526	877,571
Accumulated depreciation, depletion and amortization	(198,407)	(146,289)
Net property, plant and equipment	895,119	731,282
Equity investments	78,442	25,640
Goodwill	-	7,718
Intangible assets, net	92,672	28,938
Other long-term assets	35,141	33,967
Total assets	$ 1,218,819	$ 931,279
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	$ 60,390	$ 65,483
Accrued liabilities	10,796	10,753
Current portion of long-term debt	-	12,561
Deferred income	4,842	2,958
Derivative liabilities	13,585	41,733
Total current liabilities	89,613	133,488
Commitments and contingencies (see Note 17)		
Deferred income	6,150	6,889
Other liabilities	17,359	19,158
Derivative liabilities	6,915	1,315
Long-term debt	568,100	399,153
Partners' capital		
Common units (51,798,895 at December 31, 2008 and 46,106,285 at December 31, 2007)	526,927	373,915
General partner interest	8,000	4,753
Accumulated other comprehensive income	(4,245)	(7,392)
Total partners' capital	530,682	371,276
Total liabilities and partners' capital	$ 1,218,819	$ 931,279

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,		
	2008	2007	2006
Cash flows from operating activities			
Net income	$ 104,500	$ 56,623	$ 73,928
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	58,166	41,512	37,493
Impairments	31,801	-	-
Derivative contracts:			
Total derivative losses (gains)	(11,357)	50,163	13,213
Cash settlements of derivatives	(38,466)	(17,779)	(19,436)
Non-cash interest expense	2,693	678	769
Equity earnings, net of distributions received	(224)	(285)	1,317
Other	(1,408)	(845)	-
Changes in operating assets and liabilities:			
Accounts receivable	5,607	(12,701)	9,411
Accounts payable	(4,615)	13,435	(5,847)
Accrued liabilities	(3,613)	(1,415)	(958)
Deferred income	1,145	(1,799)	(1,676)
Other asset and liabilities	(5,053)	237	(870)
Net cash provided by operating activities	139,176	127,824	107,344
Cash flows from investing activities			
Acquisitions	(260,376)	(176,917)	(91,259)
Additions to property, plant and equipment	(71,652)	(48,123)	(38,453)
Other	998	858	36
Net cash used in investing activities	(331,030)	(224,182)	(129,676)
Cash flows from financing activities			
Distributions to partners	(111,076)	(89,649)	(66,954)
Proceeds from borrowings	453,800	220,500	85,800
Repayments of borrowings	(297,800)	(27,000)	(122,900)
Net proceeds from issuance of partners' capital	141,084	860	115,008
Other	(4,200)	(263)	(375)
Net cash provided by financing activities	181,808	104,448	10,579
Net increase (decrease) in cash and cash equivalents	(10,046)	8,090	(11,753)
Cash and cash equivalents – beginning of period	19,530	11,440	23,193
Cash and cash equivalents – end of period	$ 9,484	$ 19,530	$ 11,440
Supplemental disclosure:			
Cash paid for interest	$ 23,282	$ 15,880	$ 18,312
Noncash investing activities: (see Note 3)			
Issuance of PVR units for acquisition	$ 15,171	$ -	$ -
PVG units given as consideration for acquisition	$ 68,021	$ -	$ -
Other liabilities	$ 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		Class B Units		Subordinated Units		General Partner	Accumulated Other Comprehensive Income (Loss)	Total	Comprehensive Income (Loss)
	Units	Amount	Units	Amount	Units	Amount				
Balance at December 31, 2005	33,994	$ 296,038	-	$ -	7,650	$ (10,440)	$ 3,252	$ (4,891)	$ 283,959	$ 46,270
Capital contributions	-	-	-	-	-	-	2,298	-	2,298	
Issuance of units	416	10,601	4,012	102,109	-	-	-	-	112,710	
Conversion of subordinated units	7,650	(10,658)	-	-	(7,650)	10,658	-	-	-	
Distributions ($1.475 per unit)	-	(50,142)	-	-	-	(11,284)	(5,528)	-	(66,954)	
Net income allocation	-	57,099	-	391	-	11,066	5,372	-	73,928	$ 73,928
Other comprehensive loss	-	-	-	-	-	-	-	(3,761)	(3,761)	(3,761)
Balance at December 31, 2006	42,060	$ 302,938	4,012	$ 102,500	-	$ -	$ 5,394	$ (8,652)	$ 402,180	$ 70,167
Capital contributions	-	-	-	-	-	-	19	-	19	
Issuance of units	-	-	34	843	-	-	-	-	843	
Conversion of class B units	4,046	99,675	(4,046)	(99,675)	-	-	-	-	-	
Distributions ($1.66 per unit)	-	(73,260)	-	(3,277)	-	-	(13,112)	-	(89,649)	
Net income allocation	-	44,562	-	(391)	-	-	12,452	-	$ 56,623	$ 56,623
Other comprehensive income	-	-	-	-	-	-	-	1,260	1,260	1,260
Balance at December 31, 2007	46,106	$ 373,915	-	$ -	-	$ -	$ 4,753	$ (7,392)	$ 371,276	$ 57,883
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

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

Penn Virginia Resource Partners, L.P. (the "Partnership," "we," "us" or "our") is a publicly traded Delaware limited partnership formed by Penn Virginia Corporation ("Penn Virginia") in 2001 that is principally engaged in the management of coal and natural resource properties and the gathering and processing of natural gas in the United States. We currently conduct operations in two business segments: (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.

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 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 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 also own a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

Our general partner is Penn Virginia Resource GP, LLC, which is a wholly owned subsidiary of Penn Virginia GP Holdings, L.P. ("PVG"), a publicly traded Delaware limited partnership. At December 31, 2008, Penn Virginia owned an approximately 77% limited partner interest in PVG, as well as the non-economic general partner interest in PVG. At December 31, 2008, 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.

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 a 25% member interest in Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin and a 50% member interest in a coal handling joint venture. Earnings from our 25% member interest in Thunder Creek are recorded in the other revenues line on the consolidated statements of income, and earnings from our 50% member interest in a coal handling venture are recorded in the coal services line on the consolidated statements of income. Our investments in these equity affiliates are recorded on the equity investments line on the consolidated balance sheets. Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. These statements involve the use of estimates and judgments where appropriate.

Use of Estimates

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

Cash and Cash Equivalents

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

Property, Plant and Equipment

Property, plant and equipment consist of our ownership in coal fee mineral interests, our royalty interest in oil and natural gas wells, forestlands, processing facilities, gathering systems, compressor stations and related equipment. Property, plant and equipment are carried at cost and include expenditures for additions and improvements, such as roads and land improvements, which increase the productive lives of existing assets. Maintenance and repair costs are expensed as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. We compute depreciation and amortization of property, plant and equipment using the straight-line 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 sheets. 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 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 under Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* See Note 10, "Intangible Assets, net," for a more detailed description of our intangible assets.

Asset Retirement Obligations

In accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations,* we recognize the fair value of a liability for an 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 12 – "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 equal the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using 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. 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 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 natural gas midstream segment has completed a number of acquisitions in recent years. See Note 3, "Acquisitions," 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. 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 record a significant impairment charge on our consolidated statements of income.

Impairment of Goodwill

Goodwill has been allocated to our natural gas midstream segment. Under SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill recorded in connection with a business combination is not amortized, but tested for impairment at least annually.

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 charge of $31.8 million. As a result of this impairment charge, we did not have a balance in goodwill at December 31, 2008. We had a $7.7 million balance in goodwill at December 31, 2007. See Note 9 – "Goodwill" for a description of goodwill and the related impairment charge.

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, recording the initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect our share of income of the investees and capital contributions, and is 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 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 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 79% of our consolidated accounts receivable at December 31, 2008 resulted from our natural gas midstream segment and approximately 21% resulted from our coal and natural resource management segment. Approximately 46% of our natural gas midstream segment accounts receivables and 37% of our consolidated accounts receivable at December 31, 2008 related to three natural gas midstream customers. As of December 31, 2008, no receivables were collateralized, and we had recorded a $1.4 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 three natural gas midstream customers. This customer concentration increases our exposure to credit risk on our receivables, since the financial insolvency of any of these customers could have a significant impact on our results of operations.

At December 31, 2008, we reported a net commodity derivative asset related to the natural gas midstream segment of $22.7 million that is with two counterparties and is substantially concentrated with one 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.

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. Deferred income also includes unearned income from a coal services facility lease, which is recognized as interest income as it is earned.

Coal Services Revenues. We recognize coal services revenues when lessees use our facilities for the processing, loading and/or transportation of coal. Coal services revenues consist of fees collected from lessees for the use of our loadout facility, coal preparation plants and dock loading facility. We also include equity earnings 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.

Oil and Gas Royalty Revenues. We recognize oil and gas royalty revenues in connection with royalty interests owned by us. Royalties are recognized as revenue when natural gas, crude oil and NGLs are removed from the respective underground mineral reserve locations. Royalty payments are generally received two months after the products are removed. An accrual is included in accounts receivables for amounts not received during the month removed based on historical trends.

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

Producer Services Revenues. We recognize producer services revenues in connection with agent fees for the marketing of Penn Virginia's and other third parties' natural gas production. We aggregate third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

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 acceptable credit risks, take the form of collars and three-way collars. All derivative financial instruments are recognized in our consolidated financial statements at fair value in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. The fair values of our derivative instruments are determined based on 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.

Until April 30, 2006, we applied hedge accounting for commodity derivative financial instruments as allowed under SFAS No. 133. Our commodity derivative financial instruments initially qualified as cash flow hedges, and changes in fair value of the effective portion of these contracts were deferred in accumulated other comprehensive income ("AOCI") until the hedged transactions settled. When we discontinued hedge accounting for commodity derivatives, a net loss remained in AOCI of $12.1 million. As the hedged transactions settled in 2006, 2007 and 2008, we recognized the $12.1 million of deferred changes in fair value in revenues and cost of gas purchased in our consolidated statements of income related to commodity derivatives. As of December 31, 2008, all amounts deferred under previous commodity hedging relationships have been reclassified into revenues and cost of midstream gas purchased.

We continue to apply hedge accounting to some of our interest rate hedges. Settlements on the interest rate swap agreements (the "Interest Rate Swaps") that follow hedge accounting are recorded as interest expense. The effective portion of the change in the fair value of the swaps that follow hedge accounting are recorded each period in AOCI. Certain of the Interest Rate Swaps do not follow hedge accounting. Accordingly, mark-to-market gains and losses for the Interest Rate Swaps that do not follow hedge accounting are recognized in earnings currently in the derivatives line on the consolidated statements of income.

Because we no longer apply 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.

During the year ended December 31, 2008, we reclassified a total of $7.2 million from AOCI to earnings related to our commodity derivatives. At December 31, 2008, a $1.2 million loss remained in AOCI related to Interest Rate Swaps on which we discontinued hedge accounting. The $1.2 million loss will be recognized in earnings through the end of 2011 as the hedged transactions 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

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

We make cash distributions on the basis of cash available for distributions, not net income, in any given accounting period. In accounting periods where our net income does not exceed our distributions for such period, EITF 03-6 does not apply and basic and diluted net income per limited partner unit is determined by dividing net income by the weighted average number of limited partner units outstanding during the period.

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

	Year Ended December 31,		
	2008	2007	2006
	(in thousands, except per unit data)		
Net income	$ 104,500	$ 56,623	$ 73,928
Less: General partner's incentive distributions paid	(20,049)	(11,551)	(4,273)
Subtotal	84,451	45,072	69,655
General partner interest in net income	(1,689)	(901)	(1,099)
Limited partners' interest in net income	82,762	44,171	68,556
Additional earnings allocation to general partner under EITF 03-6	-	-	(2,949)
Net income available to limited partners under EITF 03-6	$ 82,762	$ 44,171	$ 65,607
Weighted average limited partner units, basic and diluted	49,495	46,103	42,014
Basic and diluted net income per limited partner unit	$ 1.67	$ 0.96	$ 1.56

Unit-Based Compensation

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

SFAS No. 123(R), *Share-Based Payment*, 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 16 – "Unit-Based Payments," for a more detailed description of our long-term incentive plan.

New Accounting Standards

In December 2007, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS No.141(R)"). SFAS No. 141(R) provides companies with principles and requirements on how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, liabilities assumed and any noncontrolling interest in the acquiree as well as the recognition and measurement of goodwill acquired or a gain from a bargain purchase in a business combination. SFAS No. 141(R) also requires certain disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. Acquisition costs associated with the business combination will generally be expensed as incurred. SFAS No. 141(R) became effective on January 1, 2009.

In March 2008, the EITF ratified EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*, which states that incentive distribution rights, or IDRs, in a typical master limited partnership are participating securities under SFAS No. 128, *Earnings Per Share.* According to EITF 07-4, when current-period earnings exceed cash distributions and the IDR is embedded in the general partner interest, undistributed earnings should not be allocated to the general partner (including embedded IDRs) and limited partners. Under the current accounting guidance, when current-period earnings exceed cash distributions and the IDR is embedded in the general partner interest, undistributed earnings should be allocated to the general partner. See Note 14 – "Partners' Capital and Distributions." EITF 07-4 is effective for fiscal years beginning after December 15, 2008 and applied retrospectively to all periods presented. Early application of EITF 07-4 is not permitted. Beginning on January 1, 2009, EITF 07-4 will eliminate our need to adjust our earnings per unit calculation in periods where current period earnings exceed distributions.

In April 2008, the FASB issued Staff Position No. FAS 142-3, *Determination of the Useful Life of Intangible Assets* ("FSP FAS 142-3"), which amends SFAS No. 142. The pronouncement requires that companies estimating the useful life of a recognized intangible asset consider their historical experience in renewing or extending similar arrangements or, in the absence of historical experience, consider assumptions that market participants would use about renewal or extension. FSP FAS 142-3 is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied prospectively to intangible assets acquired after the effective date. Effective January 1, 2009, we will prospectively apply FSP FAS 142-3 to all intangible assets purchased.

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 Combination

Lone Star Gathering, L.P.

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 expands 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 in accordance with SFAS No. 141, *Business Combinations.* 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
Payment guaranteed December 31, 2009	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 includes approximately $11.2 million of goodwill, all of which has been allocated to the natural gas midstream segment. A significant factor that contributed to the recognition of goodwill includes the ability to acquire an established business on the western border of the expanding Barnett Shale play in the Fort Worth Basin. Under SFAS No. 141 and SFAS 142, *Goodwill and Other Intangible Assets*, 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 under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived 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:

	(Unaudited) Year Ended December 31,	
	2008	**2007**
	(in thousands)	
Revenues	$ 885,147	$ 552,439
Net income	$ 93,363	$ 38,778
Net income per limited partner unit, basic & diluted	$ 1.44	$ 0.57

Other Business Combinations

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. The purchase price was $51.6 million in cash, after customary closing adjustments and was funded with long-term debt under the Revolver. The entire member interest is recorded in equity investments on the consolidated balance sheets. This investment includes $37.3 million of fair value for the net assets acquired and $14.3 million of fair value paid in excess of our portion of the underlying equity in the net assets acquired related to customer contracts and related customer relations. This excess is being amortized to equity earnings over the life of the underlying contracts, which is 12 years. See Note 8, "Equity Investments." The earnings are recorded in other revenues on the consolidated statements of income.

In September 2007, we acquired fee ownership of approximately 62,000 acres of forestland in northern West Virginia. The purchase price was $93.3 million in cash and was funded with long-term debt under the Revolver. The purchase price has been allocated as follows: $86.1 million to timber, $6.6 million to land and $0.6 million to oil and gas royalty interests.

In June 2007, we acquired a combination of fee ownership and lease rights to approximately 51 million tons of coal reserves, along with a preparation plant and coal handling facilities. The property is located on approximately 17,000 acres in western Kentucky. The purchase price was $42.0 million in cash and was funded with long-term debt under the Revolver. The purchase price has been allocated as follows: $30.2 million to coal properties, $11.3 million to the coal processing plant and related facilities and $0.5 million to land. We also recorded a $28.1 million lease receivable and $16.6 million to deferred rent relating to a coal services facility lease.

The pro forma results for these business combinations for the years ended December 31, 2007 and 2006 do not materially change the net income for these periods.

Other Acquisitions

Based on our analysis of the fair value of the following acquisitions, we did not deem these acquisitions to be material business combinations and therefore are not disclosing pro forma financial information in accordance with SFAS No. 141.

In October 2007, we purchased from Penn Virginia oil and gas royalty interests associated with leases of property in eastern Kentucky and southwestern Virginia and with estimated proved oil and gas reserves of 8.7 Bcfe at January 1, 2007. The purchase price for this asset acquisition was $31.0 million in cash and was funded with long-term debt under the Revolver.

In May 2006, we acquired lease rights to approximately 69 million tons of coal reserves. The reserves are located on approximately 20,000 acres in southern West Virginia. The purchase price for this asset acquisition was $65.0 million and was funded with long-term debt under the Revolver.

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 adopted SFAS No. 157, *Fair Value Measurements*, effective January 1, 2008, for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all assets and liabilities that are being measured and reported on a fair value basis. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157* ("FSP SFAS 157-2"), delayed the application of SFAS No. 157 for nonfinancial assets and nonfinancial liabilities to fiscal years and interim periods beginning after November 15, 2008. Examples of nonfinancial assets for which FSP SFAS 157-2 delays application of SFAS No. 157 include business combinations, impairment and initial recognition of an ARO.

Our financial instruments consist of cash and cash equivalents, receivables, accounts payable, derivative instruments and long-term debt. At December 31, 2008, the carrying values of all of these financial instruments approximated fair value. As a result of repaying our Senior Unsecured Notes due 2013 (the "Notes"), we had no fixed-rate long-term debt as of December 31, 2008. See Note 13 – "Long-Term Debt." At December 31, 2007, the carrying values of all of these financial instruments, except fixed-rate long-term debt, approximated fair value. The fair value of fixed-rate long-term debt at December 31, 2007 was $65.8 million.

SFAS No. 157 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).

The following table summarizes the valuation of our financial instruments by the above SFAS No. 157 categories as of December 31, 2008 (in thousands):

		Fair Value Measurements at December 31, 2008, Using		
Description	Fair Value Measurements at December 31, 2008	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Interest rate swap liability - current	$ (5,891)	$ -	$ (5,891)	$ -
Interest rate swap liability - noncurrent	(6,915)	-	(6,915)	-
Commodity derivative assets - current	30,431	-	30,431	-
Commodity derivative liability - current	(7,694)	-	(7,694)	-
Total	**$ 9,931**	**$ -**	**$ 9,931**	**$ -**

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: Our natural gas midstream segment's commodity derivatives utilize three-way collar derivative contracts. We also utilize collar derivative contracts to hedge against the variability in the 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. This is a level 2 input. We generally 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. This is a level 2 input. See Note 6 – "Derivative Instruments."

6. Derivative Instruments

Natural Gas Midstream Segment Commodity Derivatives

We utilize three-way collar 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.

A three-way collar contract consists of a collar contract plus a put option contract sold by us with a price below the floor price of the collar. The counterparty to a collar contract is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract.

The additional put option sold by us requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put option price. By combining the collar contract with the additional put option, we are entitled to a net payment equal to the difference between the floor price of the collar contract and the additional put option price if the settlement price is equal to or less than the additional put option price. If the settlement price is greater than the additional put option price, the result is the same as it would have been with a collar contract only. If market prices are below the additional put option, we would be entitled to receive the market price plus the difference between the additional put option and the floor. See the natural gas midstream segment commodity derivative table in this footnote. This strategy enables us to increase the floor and the ceiling prices of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option.

We determine the fair values of our derivative agreements based on discounted cash flows based on quoted forward prices for the respective commodities as of December 31, 2008, 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, 2008 for commodities related to natural gas midstream revenues and cost of midstream gas purchased:

		Weighted Average Price			
	Average Volume Per Day	Additional Put Option	Floor	Ceiling	Fair Value (in thousands)
Crude Oil Three-way Collar	(in barrels)		(per barrel)		
First Quarter 2009 through Fourth Quarter 2009	1,000	$ 70.00	$ 90.00	$ 119.25	$ 6,101
Frac Spread Collar	(in MMBtu)		(per MMBtu)		
First Quarter 2009 through Fourth Quarter 2009	6,000		$ 9.09	$ 13.94	14,943
Settlements to be received in subsequent month					1,694
Natural gas midstream segment commodity derivatives - net asset					$ 22,738

At December 31, 2008, we reported a net derivative asset related to the natural gas midstream segment of $22.7 million. No amounts remain in AOCI related to derivatives in the natural gas midstream segment for which we discontinued hedge accounting in 2006. See the *Adoption of SFAS No. 161* section below for the impact of the natural gas midstream commodity derivatives on our consolidated statements of income.

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. Until March 2010, the notional amounts of the Interest Rate Swaps total $285.0 million, or approximately 50% of our total long-term debt outstanding as of December 31, 2008, with us paying a weighted average fixed rate of 3.67% on the notional amount, and the counterparties paying a variable rate equal to the three-month London Interbank Offered Rate ("LIBOR"). From March 2010 to December 2011, the notional amounts of the Interest Rate Swaps total $225.0 million with us paying a weighted average fixed rate of 3.52% 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 $75.0 million, with us paying a weighted average fixed rate of 2.10% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. The Interest Rate Swaps extend one year past the maturity of the current Revolver. The Interest Rate Swaps have been entered into with six financial institution counterparties, with no counterparty having more than 26% of the open positions. In January 2009, we entered into an additional $25.0 million interest rate swap with a maturity of December 2012. Inclusive of this additional interest rate swap, the weighted average fixed interest rate we pay to our counterparties is 3.54% through March 2010, 3.37% from March 2010 through December 2011, and 2.09% from December 2011 through December 2012.

We continue to apply hedge accounting to some of our interest rate hedges. Settlements on the Interest Rate Swaps that follow hedge accounting are recorded as interest expense. Accordingly, the effective portion of the change in the fair value of the transactions for the swaps that follow hedge accounting are recorded each period in AOCI. Certain of our Interest Rate Swaps do not follow hedge accounting. Accordingly, mark-to-market gains and losses for the Interest Rate Swaps that do not follow hedge accounting are recognized in earnings currently. At December 31, 2008, a $1.2 million loss remained in AOCI related to Interest Rate Swaps on which we discontinued hedge accounting. The $1.2 million loss will be recognized in earnings through the end of 2011 as the hedged transactions settle.

We reported a (i) net derivative liability of $12.8 million at December 31, 2008 and (ii) loss in AOCI of $4.2 million at December 31, 2008 related to the Interest Rate Swaps. In connection with periodic settlements, we recognized $1.7 million of net hedging losses in interest expense in the year ended December 31, 2008. Based upon future interest rate curves at December 31, 2008, we expect to realize $5.9 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.

Adoption of SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an Amendment of FASB Statement No. 133*, which amends and expands the disclosures required by SFAS No. 133. We elected to adopt SFAS No. 161 early, effective June 30, 2008. SFAS No. 161 requires companies to disclose how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows.

In the year ended December 31, 2008, we reclassified a total of $7.2 million out of AOCI and into earnings. We also recorded unrealized hedging losses of $4.0 million in AOCI in the year ended December 31, 2008 related to the Interest Rate Swaps. See Note 18, "Comprehensive Income," for a detailed schedule of our AOCI.

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 year ended December 31, 2008 (in thousands):

	Location of gain (loss) on derivatives recognized in income	Year Ended December 31, 2008
Derivatives designated as hedging instruments under SFAS No. 133 (Effective portion):		
Interest rate contracts (1)	Interest expense	$ (503)
Increase (decrease) in net income resulting from derivatives designated as hedging instruments under SFAS No. 133 (Effective portion)		**$ (503)**
Derivatives not designated as hedging instruments under SFAS No. 133:		
Interest rate contracts	Derivatives	$ (8,635)
Interest rate contracts (1)	Interest expense	(1,203)
Commodity contracts (1)	Natural gas midstream revenues	(8,219)
Commodity contracts (1)	Cost of midstream gas purchased	2,739
Commodity contracts	Derivatives	25,472
Increase (decrease) in net income resulting from derivatives not designated as hedging instruments under SFAS No. 133		**$ 10,154**
Total increase (decrease) in net income resulting from derivatives		**$ 9,651**
Realized and unrealized derivative impact:		
Cash paid for commodity and interest rate contract settlements	Derivatives	(38,466)
Cash paid for interest rate contract settlements	Interest expense	(503)
Unrealized derivative gain	(2)	48,620
Total increase (decrease) in net income resulting from derivatives		**$ 9,651**

(1) This represents 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. At December 31, 2008, a $1.2 million loss remained in AOCI related to Interest Rate Swaps on which we discontinued hedge accounting in 2008.

(2) 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, 2008 (in thousands):

	Balance Sheet Location	Fair values as of December 31, 2008	
		Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments under SFAS No. 133:			
Interest rate contracts	Derivative liabilities - current	$ -	$ 1,228
Interest rate contracts	Derivative liabilities - noncurrent	-	1,842
Total derivatives designated as hedging instruments under SFAS No. 133		$ -	$ 3,070
Derivatives not designated as hedging instruments under SFAS No. 133:			
Interest rate contracts	Derivative liabilities - current	$ -	$ 4,663
Interest rate contracts	Derivative liabilities - noncurrent	-	5,073
Commodity contracts	Derivative assets/liabilities - current	30,431	7,694
Total derivatives not designated as hedging instruments under SFAS No. 133		$ 30,431	$ 17,430
Total fair values of derivative instruments		**$ 30,431**	**$ 20,500**

See Note 5, "Fair Value Measurement of Financial Instruments" for a description of how the above financial instruments are valued in accordance with SFAS No. 157.

The following table summarizes the effect of the Interest Rate Swaps on our total interest expense for the year ended December 31, 2008 (in thousands):

Source	**Year Ended December 31, 2008 (in thousands)**
Borrowings	$ (23,641)
Capitalized interest (1)	675
Interest rate swaps	(1,706)
Total interest expense	$ (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 that do not follow hedge accounting are reported as adjustments to reconcile net income to net cash provided by operating activities on our consolidated statements of cash flows. These items are recorded in the "Total derivative losses (gains)" and "Cash settlements of derivatives" lines on the consolidated statements of cash flows.

The above hedging activity represents cash flow hedges. As of December 31, 2008, we did not own derivative instruments that were classified as fair value hedges or trading securities. In addition, as of December 31, 2008, 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, 2008 and 2007:

	As of December 31, 2008	As of December 31, 2007
	(in thousands)	
Coal properties	$ 476,787	$ 453,484
Compressor stations	53,392	49,693
Gathering systems	334,522	159,652
Coal services equipment	38,474	38,840
Processing plants	38,150	28,695
Land	20,985	17,753
Oil and gas royalties	36,937	36,395
Timber	87,869	87,800
Other property, plant and equipment	6,410	5,259
Total property, plant and equipment	1,093,526	877,571
Accumulated depreciation, depletion and amortization	(198,407)	(146,289)
Net property, plant and equipment	$ 895,119	$ 731,282

8. Equity Investments

In 2004, we acquired a 50% interest in Coal Handling Solutions LLC, a joint venture formed to own and operate end-user coal handling facilities. In 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 for $51.6 million in cash, after customary closing adjustments. See Note 3 – "Acquisitions." We account for these investments under the equity method of accounting. As of December 31, 2008 and 2007, our equity investment totaled $78.4 million and $25.6 million, which exceeded our portion of the underlying equity in net assets by $21.0 million and $7.7 million. The difference is being amortized to equity earnings over the life of coal services contracts in place at the time of the acquisition. Included in the equity investment balance at December 31, 2008 and 2007 was $21.0 million and $7.7 million of net intangible assets related to contracts and customer relationships acquired, which is estimated to be from 12 years to 15 years.

In accordance with the equity method, we recognized equity earnings of $4.2 million in 2008, $1.8 million in 2007 and $1.3 million in 2006, with a corresponding increase in the investment. The joint ventures generally pay to us quarterly distributions of our portion of the joint ventures' cash flows. We received cash distributions from the joint ventures of $4.0 million in 2008, $1.5 million in 2007 and $2.7 million in 2006. Equity earnings related to the 50% interest in Coal Handling Solutions LLC are included in coal services revenues on our consolidated statements of income, and equity earnings related to the 25% member interest in Thunder Creek are recorded in other revenues on our consolidated statements of income. The equity investments for both joint ventures are included in the equity investments line on our consolidated balance sheets.

9. Goodwill

The changes in the carrying amount of goodwill for the year ended December 31, 2008 are as follows:

	Natural gas midstream segment
Balance at January 1, 2008	$ 7,718
Goodwill acquired during year	24,083
Impairment loss incurred during year	(31,801)
Balance at December 31, 2008	$ -

In accordance with SFAS No. 142, we test goodwill for impairment on an annual basis, at a minimum, and more frequently if a triggering event occurs. Our annual impairment testing of goodwill and other intangible assets, using the guidance prescribed by SFAS No. 142, resulted in an impairment to goodwill of approximately $31.8 million in the fourth quarter of 2008. 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, reduces 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 is 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. Our goodwill balance at December 31, 2007 was $7.7 million.

10. Intangible Assets, net

The following table summarizes our net intangible assets as of December 31, 2008 and 2007:

	As of December 31, 2008	As of December 31, 2007
	(in thousands)	
Contracts and customer relationships	$ 106,900	$ 37,700
Rights-of-way	4,552	4,552
Total intangible assets	111,452	42,252
Accumulated amortization	(18,780)	(13,314)
Intangible assets, net	$ 92,672	$ 28,938

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 a straight-line basis 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, 2008, 2007 and 2006 was approximately $5.5 million, $4.1 million and $5.0 million. As of December 31, 2008 and 2007, accumulated amortization of intangible assets was $18.8 million and $13.3 million. The following table sets forth our estimated aggregate amortization expense for the next five years and thereafter:

Year	Amortization Expense
	(in thousands)
2009	$ 9,538
2010	9,054
2011	8,467
2012	7,779
2013	7,560
Thereafter	70,498
Total	$ 112,896

11. Allowance for Prepaid Minimums

We establish provisions for losses on long-term prepaid minimums if we determine that we will not recoup all or part of the outstanding balance. Collectibility is reviewed periodically and an allowance is established or adjusted, as necessary, using the specific identification method. The allowance is netted against long-term prepaid minimums on our consolidated balance sheets. The following table presents the activity of our allowance for prepaid minimums for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Balance at beginning of period	$1,646	$1,737	$1,692
Charges to expense	326	(91)	60
Forfeiture of prepaid minimum	-	-	(15)
Balance at end of period	$1,972	$1,646	$1,737

12. Asset Retirement Obligations

The following table reconciles the beginning and ending aggregate carrying amount of our AROs for the years ended December 31, 2008 and 2007, which are recorded in other liabilities on our consolidated balance sheets:

	Year Ended December 31,	
	2008	2007
	(in thousands)	
Balance at beginning of period	$ 2,028	$ 1,881
Revision of estimate	(505)	-
Accretion expense	291	147
Balance at end of period	$ 1,814	$ 2,028

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

13. Long-Term Debt

The following table summarizes our long-term debt as of December 31, 2008 and 2007:

	As of December 31,	
	2008	2007
	(in thousands)	
Revolver – variable rate of 4.4% and 6.2% at December 31, 2008 and 2007	$ 568,100	$ 347,700
Notes	-	64,014
Total debt	568,100	411,714
Less: Current maturities	-	(12,561)
Total long-term debt	$ 568,100	$ 399,153

We capitalized interest costs amounting to $0.7 million and $0.8 million in the years ended December 31, 2008 and 2007 related to the construction of two natural gas processing plants. We capitalized interest costs amounting to $0.3 million in the year ended December 31, 2006 related to the construction of a coal services facility in October 2006.

Revolver

As of December 31, 2008, net of outstanding borrowings of $568.1 million and letters of credit of $1.6 million, we had remaining borrowing capacity of $130.3 million on the Revolver. In August 2008, we increased the size of our Revolver from $600.0 million to $700.0 million and secured the Revolver with substantially all of our assets. The Revolver matures in December 2011 and is available to us for general purposes, including working capital, capital expenditures and acquisitions, and includes a $10.0 million sublimit for the issuance of letters of credit. In 2008, we incurred commitment fees of $0.5 million on the unused portion of the Revolver. The interest rate under the Revolver fluctuates based on the ratio of our total indebtedness-to-EBITDA. Interest is payable at a base rate plus an applicable margin of up to 0.75% if we select the base rate borrowing option under the Revolver or at a rate derived from LIBOR plus an applicable margin ranging from 0.75% to

1.75% if we select the LIBOR-based borrowing option. The weighted average interest rate on borrowings outstanding under the Revolver during 2008 was approximately 4.6%. We do not have a public credit rating for the Revolver.

The financial covenants under the Revolver require us not to exceed specified ratios. The Revolver prohibits us from making distributions to our partners if any potential default, or event of default, as defined in the Revolver, occurs or would result from the distributions. In addition, the Revolver contains various covenants that limit our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, or enter into a merger or sale of our assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2008, we were in compliance with all of our covenants under the Revolver.

Notes

In July 2008, we paid an aggregate of $63.3 million to the holders of the Notes to prepay 100% of the aggregate principal amount of the Notes. This amount consisted of approximately $58.4 million aggregate principal amount outstanding on the Notes, $1.1 million in accrued and unpaid interest on the Notes through the prepayment date and $3.8 million in make-whole amounts due in connection with the prepayment. The $3.8 million of make-whole payments were recorded in interest expense on our consolidated statements of income. The Notes were repaid with borrowings under the Revolver. While the Notes were outstanding, we had a DBRS public credit rating. However, due to the repayment of the Notes, we have elected not to renew this rating. As of December 31, 2007, we owed $64.0 million under the Notes, the current portion of which was $12.6 million. The Notes bore interest at a fixed rate of 6.02%.

Debt Maturities

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

Year	Aggregate Maturities of Principal Amounts
	(in thousands)
2009	$ -
2010	-
2011	568,100
2012	-
2013	-
Thereafter	-
Total principal	568,100
Less: Terminated interest rate swap	-
Total debt, including current maturities	$ 568,100

14. Partners' Capital and Distributions

As of December 31, 2008, partners' capital consisted of 51.8 million common units, representing a 98% limited partner interest and a 2% general partner interest. As of December 31, 2008, affiliates of Penn Virginia, in the aggregate, owned a 39% interest in us, consisting of 19.6 million common units and a 2% general partner interest.

Unit Split

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

Subordinated Units

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

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

Cash Distributions

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

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

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

The following table reflects the allocation of total cash distributions paid by us during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands, except per unit information)		
Limited partner units	$ 89,207	$ 76,536	$ 61,427
General partner interest (2%)	1,820	1,562	1,254
Incentive distribution rights	20,049	11,551	4,273
Total cash distributions paid	$ 111,076	$ 89,649	$ 66,954
Total cash distributions paid per unit	$ 1.82	$ 1.66	$ 1.48

On February 13, 2009, we paid a $0.47 quarterly distribution per unit to unitholders of record on February 2, 2009. This distribution was unchanged from the previous distribution paid on November 14, 2008.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to 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.

15. Related Party Transactions

General and Administrative

Penn Virginia charges us for certain corporate administrative expenses which are allocable to us and our subsidiaries. When allocating general corporate expenses, consideration is given to property and equipment, payroll and general corporate overhead. Any direct costs are paid by us. Total corporate administrative expenses charged to us and our subsidiaries totaled $5.1 million, $4.2 million and $4.5 million for the years ended December 31, 2008, 2007 and 2006. These costs are reflected in general and administrative expenses in our consolidated statements of income. At least annually, our management performs an analysis of general corporate expenses based on time allocations of shared employees and other pertinent factors. Based on this analysis, our management believes that the allocation methodologies used are reasonable.

Accounts Payable—Affiliate

Amounts payable to related parties totaled $8.0 million and $2.4 million as of December 31, 2008 and 2007. The increase in the balance in 2008 is due primarily to amounts due to a wholly owned subsidiary of Penn Virginia, Penn Virginia Oil & Gas, L.P. ("PVOG LP"), related to the natural gas gathering and processing agreement between PVR East Texas Gas Processing, LLC ("PVR East Texas") and PVOG LP. See "*– Gathering and Processing Revenues.*" These balances are included in accounts payable on our consolidated balance sheets.

Marketing Revenues

PVOG LP and Connect Energy Services, LLC ("Connect Energy"), our wholly owned subsidiary, are parties to a Master Services Agreement effective September 1, 2006. Pursuant to the Master Services Agreement, PVOG LP and Connect Energy have agreed that Connect Energy will market all of PVOG LP's oil and gas production in Arkansas, Louisiana, Oklahoma and Texas for a fee equal to 1% of the net sales price (subject to specified limitations) received by PVOG LP for such production. The Master Services Agreement has a primary term of five years and automatically renews for additional one-year terms until terminated by either party. Under the Master Services Agreement, PVOG LP paid fees to Connect Energy of $3.0 million, $2.2 million and $0.4 million for the years ended December 31, 2008, 2007 and 2006. Marketing revenues are included in other revenues on our consolidated statements of income.

Gathering and Processing Revenues

PVR East Texas and PVOG LP are parties to a natural Gas Gathering and Processing Agreement effective April 1, 2007. Pursuant to the Gas Gathering and Processing Agreement, PVOG LP and PVR East Texas have agreed that PVR East Texas will gather and process all of PVOG LP's current and future gas production in certain areas of the Bethany Field in East Texas and redeliver the NGLs to PVOG LP for a $0.30/MMBtu service fee (with an annual CPI adjustment). The Gas Gathering and Processing Agreement has a primary term of 15 years and automatically renews for additional one year terms until terminated by either party. PVR East Texas began gathering and processing PVOG LP's gas in June 2008. In 2008, PVOG LP paid PVR East Texas $2.0 million in fees pursuant to the Gas Gathering and Processing Agreement. These gathering and processing revenues are recorded in the natural gas midstream line on our consolidated statements of income.

From time to time, PVOG LP sells gas or NGLs to Connect Energy at our Crossroads Plant, Connect Energy transports them to the marketing location, and then Connect Energy resells such gas or NGLs to third parties. The sales price received by PVOG LP from Connect Energy for such gas or NGLs equals the sales price received by Connect Energy for such gas or NGLs from the third parties. In 2008, PVOG LP received $127.9 million from Connect Energy in connection with such sales. In 2008, we recorded $127.9 million of natural gas midstream revenue 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, nor do they impact operating income other than the fee collected earlier in the process.

16. Unit-Based Payments

Long-Term Incentive Plan

We account for our long-term incentive plan under the standards outlined in SFAS No. 123(R). SFAS No. 123(R) 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.

At December 31, 2008, our long-term incentive plan permitted the grant of awards to employees and directors of our general partner and employees of its affiliates who perform services for us. In January 2009, our long-term incentive plan was amended to permit the granting 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 our long-term incentive plan can be in the form of common units, restricted units, unit options, phantom units and deferred common units. Our long-term incentive plan is administered by the compensation and benefits committee of our general partner's board of directors. We reimburse our general partner for payments made pursuant to our long-term incentive plan and recognize compensation cost based on the fair value of the awards over the vesting period.

We recognized a total of $3.2 million, $2.4 million and $1.9 million in the years ended December 31, 2008, 2007 and 2006 of compensation expense related to the granting of common units and deferred common units and the vesting of restricted units granted under the long-term incentive plan. These expenses are recorded on the general and administrative expense line on our consolidated statements of income.

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

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

The following table summarizes the status of our nonvested restricted units as of December 31, 2008 and changes during the year then ended:

	Nonvested Restricted Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2008	156,931	$ 27.40
Granted	138,251	26.57
Vested	(71,074)	27.27
Forfeit	(2,253)	27.09
Nonvested at December 31, 2008	221,855	$ 26.93

At December 31, 2008, we had $3.7 million of total unrecognized compensation cost related to nonvested restricted units. We expect to reimburse our general partner for that cost over a weighted-average period of 0.9 years. The total grant-date fair value of restricted units that vested in 2008, 2007 and 2006 was $1.9 million, $1.2 million and $2.2 million.

Deferred Common Units. A portion of the compensation to the non-employee directors of our general partner is paid in deferred common units. Each deferred common unit represents one common unit, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of our general partner. Our general partner granted 21,337 deferred common units in 2008 at a weighted-average grant-date fair value of $23.85. Our general partner granted 22,209 deferred common units in 2007 at a weighted average grant-date fair value of $26.43.

At December 31, 2008, 56,433 deferred common units were outstanding at a weighted average grant-date fair value of $24.87. In 2008, 26,122 deferred common units converted to common units. At December 31, 2007, 61,218 deferred common units were outstanding at a weighted average grant-date fair value of $25.58. At December 31, 2006, 39,009 deferred common units were outstanding at a weighted average grant-date fair value of $25.26 per common unit. The aggregate intrinsic value of deferred common units converted to common units in 2008 and 2006 was $0.7 million and $0.2 million. No deferred common units converted to common units in 2007.

17. Commitments and Contingencies

Rental Commitments

Operating lease rental expense in the years ended December 31, 2008, 2007 and 2006 was $4.5 million, $2.6 million and $1.9 million. The following table sets forth our minimum rental commitments for the next five years under all non-cancelable operating leases in effect at December 31, 2008:

Year	Minimum Rental Commitments
	(in thousands)
2009	$ 2,678
2010	1,891
2011	1,680
2012	1,332
2013	1,296
Thereafter	5,807
Total minimum payments	$ 14,684

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, 2008, we had contracts for firm transportation capacity rights for specified volumes per day on a pipeline system with terms that ranged from one to seven years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion. The following table sets forth our obligation for firm transportation commitments in effect at December 31, 2008 for the next five years and thereafter:

Year	Firm Transportation Commitments
	(in thousands)
2009	$ 13,069
2010	6,168
2011	5,694
2012	4,508
2013	4,033
Thereafter	3,321
Total firm transportation commitments	$ 36,793

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, 2008 and 2007, our environmental liabilities were $1.2 million and $1.5 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.

18. Comprehensive Income

Comprehensive income represents changes in partners' capital during the reporting period, including net income and charges directly to partners' capital which are excluded from net income. The following table sets forth the components of comprehensive income for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Net income	$ 104,500	$ 56,623	$ 73,928
Unrealized losses on derivative activities	(4,039)	(2,599)	(5,669)
Reclassification adjustment for derivative activities	7,186	3,859	1,909
Comprehensive income	$ 107,647	$ 57,883	$ 70,168

Included in the comprehensive income balance at December 31, 2008 is $1.2 million of losses relating to Interest Rate Swaps on which we discontinued hedge accounting. The $1.2 million loss will be recognized in earnings through the end of 2011 as the hedged transactions settle. See Note 6, "Derivative Instruments."

19. Segment Information

Segment information has been prepared in accordance with SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.* Under SFAS No. 131, operating segments are defined as components of an enterprise about which separate financial information is available and is evaluated regularly by the chief operating decision maker, or decision-making group, in assessing performance. Our decision-making group consists of our Chief Executive Officer and other senior officers. This group routinely reviews and makes operating and resource allocation decisions among our coal and natural resource management operations and our natural gas midstream operations. Accordingly, our reportable segments are as follows:

- Coal and Natural Resource Management—management and leasing of coal properties and subsequent collection of royalties; other land management activities such as selling standing timber; leasing of fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants; collection of oil and gas royalties; and coal transportation, or wheelage, fees.
- Natural Gas Midstream—natural gas processing, gathering and other related services.

The following table presents a summary of certain financial information relating to our segments as of and for the years ended December 31, 2008, 2007 and 2006:

	Revenues			Operating income		
	2008	2007	2006	2008	2007	2006
Coal and natural resource (1)	$ 153,327	$ 111,639	$ 112,981	$ 96,296	$ 68,811	$ 73,444
Natural gas midstream (2)	728,253	437,806	404,910	18,946	48,914	29,376
Consolidated totals	$ 881,580	$ 549,445	$ 517,891	$ 115,242	$ 117,725	$ 102,820
Interest expense				$ (24,672)	$ (17,338)	$ (18,821)
Other				(2,907)	1,804	1,189
Derivatives				16,837	(45,568)	(11,260)
Consolidated net income				$ 104,500	$ 56,623	$ 73,928

	Additions to property and equipment			DD&A expense		
	2008	2007	2006	2008	2007	2006
Coal and natural resource	$ 27,270	$ 177,960	$ 92,697	$ 30,805	$ 22,690	$ 20,399
Natural gas midstream	304,758	47,080	37,015	27,361	18,822	17,094
Consolidated totals	$ 332,028	$ 225,040	$ 129,712	$ 58,166	$ 41,512	$ 37,493

	Total assets at December 31,		
	2008	2007	2006
Coal and natural resource (3)	$ 600,418	$ 610,866	$ 409,709
Natural gas midstream (4)	618,402	320,413	304,314
Consolidated totals	$ 1,218,820	$ 931,279	$ 714,023

(1) Our coal and natural resource management segment's revenues for the years ended December 31, 2008, 2007 and 2006 include $1.8 million, $1.8 million and $1.3 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 year ended December 31, 2008 include $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.

(3) Total assets at December 31, 2008, 2007 and 2006 for the coal and natural resource management segment included equity investment of $23.4 million, $25.6 million and $25.3 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, 2008 for the natural gas midstream segment included equity investment of $55.0 million related to our 25% member interest in Thunder Creek that we acquired in 2008. See Note 8 – "Equity Investments" for a further description. Total assets at December 31, 2007 and 2006 for the natural gas midstream segment included goodwill of $7.7 million.

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, 2008, two of our natural gas midstream segment customers accounted for $194.9 million and $93.8 million, or 22% 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, 2007, three customers of our natural gas midstream segment accounted for approximately $109.2 million, $61.0 million and $60.5 million, or 20%, 11% and 11%, of our total consolidated net revenues. For the year ended December 31, 2006, two customers of our natural gas midstream segment accounted for $129.1 million and $67.4 million, or 25% and 13%, of our total consolidated net revenues.

Supplemental Quarterly Financial Information (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
		(in thousands, except unit data)		
2008				
Revenues	$ 156,814	$ 276,505	$ 285,276	$ 162,985
Operating income (1)	$ 31,234	$ 44,329	$ 40,023	$ (344)
Net income	$ 34,540	$ 9,471	$ 44,552	$ 15,937
Basic and diluted net income per limited partner unit (2)	$ 0.55	$ 0.10	$ 0.60	$ 0.19
Weighted average number of units outstanding, basic and diluted	46,106	48,581	51,663	51,799
2007				
Revenues	$ 124,200	$ 144,144	$ 130,204	$ 150,897
Operating income	$ 22,340	$ 27,382	$ 31,771	$ 36,232
Net income	$ 16,433	$ 16,560	$ 16,662	$ 6,968
Basic and diluted net income per limited partner unit (2)	$ 0.30	$ 0.30	$ 0.29	$ 0.07
Weighted average number of units outstanding, basic and diluted	46,106	46,107	46,106	46,106
2006				
Revenues	$ 135,164	$ 123,463	$ 131,494	$ 127,770
Operating income	$ 18,246	$ 29,289	$ 29,898	$ 25,387
Net income	$ 8,340	$ 13,221	$ 31,339	$ 21,028
Basic and diluted net income per limited partner unit (2)	$ 0.19	$ 0.30	$ 0.55	$ 0.41
Weighted average number of units outstanding, basic and diluted	41,644	41,644	41,644	43,121

(1) Operating income in 2008 included a loss on the impairment of goodwill of $31.8 million that we recorded in the fourth quarter of 2008. See Note 9, "Goodwill."

(2) 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. See Note 2 – "Summary of Significant Accounting Policies."

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, 2008. 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, 2008, 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, 2008. 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, 2008, 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, 2008, 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***

There was no information that was required to be disclosed by us on a Current Report on Form 8-K during the fourth quarter of 2008 which we did not disclose.

Part III

Item 10 ***Directors, Executive Officers and Corporate Governance***

Directors and Executive Officers

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

Name	Age	Position with Our General Partner
A. James Dearlove	61	Chairman of the Board of Directors and Chief Executive Officer
Edward B. Cloues, II	61	Director
James L. Gardner	57	Director
James R. Montague	61	Director
Marsha R. Perelman	58	Director
Frank A. Pici	53	Director and Vice President and Chief Financial Officer
Nancy M. Snyder	55	Director and Vice President, Chief Administrative Officer and General Counsel
Keith D. Horton	55	Co-President and Chief Operating Officer—Coal
Ronald K. Page	58	Co-President and Chief Operating Officer—Midstream

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

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

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

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

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

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

Nancy M. Snyder has served as Vice President and General Counsel and as a director of our general partner since July 2001 and as Chief Administrative Officer since May 2008 and as Vice President and General Counsel and as a director of PVG's general partner since September 2006 and as Chief Administrative Officer since May 2008. Ms. Snyder has also served in various capacities with Penn Virginia since 1997, including as Executive Vice President since May 2006, as Chief Administrative Officer since May 2008, as Senior Vice President from February 2003 to May 2006, as Vice President from December 2000 to February 2003 and as General Counsel and Corporate Secretary since 1997.

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

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

Role of the Board of Directors of our General Partner

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

Code of Business Conduct and Ethics

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

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

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

Committees of the Board of Directors of our General Partner

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

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

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

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires officers and directors of our general partner and beneficial owners more than 10% of our common units to file, by a specified date, reports of beneficial ownership and changes in beneficial ownership with the SEC and to furnish copies of such reports to us. We believe that all such filings were made on a timely basis in 2008 except as described below.

In 2008, we inadvertently filed five late Forms 4 on behalf of Penn Virginia with respect to five transactions. In addition, we inadvertently failed to file of behalf of Forrest W. McNair, our controller, of any of the seven Form 4s required to be filed on his behalf with respect to seven transactions between May 2005 and February 2008. On May 22, 2008, we filed a Form 4 on behalf of Mr. McNair reporting all of such transactions.

Item 11 *Executive Compensation*

Compensation Discussion and Analysis

Under the rules established by the SEC, we are required to provide a discussion and analysis of information necessary to an understanding of our compensation policies and decisions regarding our Chief Executive Officer, or our CEO, Chief

Financial Officer, or our CFO, and the other executive officers of our general partner named in the Summary Compensation Table included in this Annual Report on Form 10-K. The required disclosure includes the use of specified tables and a report of the compensation and benefits committee of our general partner. Unless otherwise indicated, all references in this Annual Report on Form 10-K to "our NEOs" refer to the executive officers named in the Summary Compensation Table, all references to "our Committee" or the "Committee" refer to the compensation and benefits committee of our general partner, all references to the "Penn Virginia Committee" refer to the compensation and benefits committee of Penn Virginia and all references to the "PVG Committee" refer to the compensation and benefits committee of PVG's general partner..

Compensation Structure

Penn Virginia indirectly controls our general partner and owns 100% of our IDRs and a significant limited partner interest in us. Because of this relationship, and since all of our NEOs are also executives of Penn Virginia and three of our NEOs, including our CEO, devote a majority of their professional time to Penn Virginia, the Penn Virginia Committee sets compensation for our NEOs. A. James Dearlove, our CEO, Frank A. Pici, our Vice President and CFO, and Nancy M. Snyder, our Vice President, Chief Administrative Officer and General Counsel, who are referred to in this Annual Report on Form 10-K as the "Shared Executives," are employees of Penn Virginia and rendered services not only to us, but also to Penn Virginia and PVG, during 2008. We are responsible for reimbursing to Penn Virginia that portion of the Shared Executives' compensation related to the services they perform for us. The specific portions of compensation reimbursed to Penn Virginia by us are determined based on the portion of professional time devoted by each Shared Executive to us. The Shared Executives are required to document the amount of professional time they spend rendering services to us. See "How Compensation Is Determined—Committee Process" for a discussion of our Committee's review of such allocations. Two of our NEOs, Keith D. Horton, Co-President and Chief Operating Officer—Coal of our general partner, and Ronald K. Page, Co-President and Chief Operating Officer—Midstream of our general partner, who are referred to in this Annual Report on Form 10-K as the "Partnership Executives," render their services solely to us so we pay all of their compensation.

Objectives of the Compensation Program

The compensation program is based on the following objectives:

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

Elements of Compensation

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

- *Base Salary*—We and Penn Virginia pay each of our NEOs an industry-competitive salary so that we can attract and retain talented executives. The base salaries also reflect the capabilities, levels of experience, tenure, positions and responsibilities of our NEOs. See "How Compensation Is Determined—Considerations in Light of Current Economic Conditions" for a discussion regarding 2009 NEO salary freezes.
- *Annual Cash Bonus*—We and Penn Virginia provide each of our NEOs the opportunity to earn an industry-competitive annual cash bonus. This opportunity creates a strong financial incentive for our NEOs to achieve or exceed a combination of partnership and individual goals. The performance criteria by which each NEO is measured and other factors affecting the compensation of our NEOs are described below under the headings "How Compensation Is Determined—Peer Benchmarks for the Partnership," "How Compensation Is Determined—Peer

Benchmarks for Penn Virginia," "How Compensation Is Determined—Partnership, Company and Individual Performance Criteria" and "How Compensation Is Determined—Performance Criteria and Risk Assessment." In addition to the performance criteria, our Committee and the Penn Virginia Committee may consider any other factors they deem appropriate when awarding annual cash bonuses to our NEOs.

- *Long-Term Compensation Awards*—We and Penn Virginia provide each of our NEOs the opportunity to earn an industry-competitive annual long-term compensation award. This opportunity creates a strong financial incentive for our NEOs to promote the long-term financial and operational success of the Partnership and to encourage a significant equity stake in the Partnership. We and Penn Virginia require our CEO and the other Shared Executives to own common units and shares of Penn Virginia's common stock valued at an aggregate amount equal to four times base salary, in the case of our CEO, and two times base salary, in the case of the other Shared Executives, with the proportion of units and stock being reflective of the amount of time they devote to us and Penn Virginia. We require each Partnership Executive to own common units valued at two times his base salary. Long-term compensation awards are expressed in dollar values, and we pay those awards in the form of restricted units or phantom units. Penn Virginia pays those awards in the form of stock options, restricted stock or restricted stock units. The actual numbers of restricted units and shares of restricted stock awarded are based on the NYSE closing prices of our common units and Penn Virginia's common stock on the dates of grant. The actual number of stock options awarded is based on a weighted-average value of all options granted to all classes of Penn Virginia's employees on the date of grant using the Black-Scholes-Merton option-pricing formula. The Shared Executives' long-term compensation awards are split between restricted units or phantom units of us, on the one hand, and stock options, restricted stock or restricted stock units of Penn Virginia, on the other hand. For each Shared Executive, the ratio of the split between Partnership-related long-term compensation and Penn Virginia-related long-term compensation is determined based on the amount of time such Shared Executive devotes to us, on the one hand, and Penn Virginia and PVG, on the other hand. Time devoted to PVG is included with time devoted to Penn Virginia for the purpose of splitting the type of long-term compensation awards because PVG is a majority-owned subsidiary of Penn Virginia. Executives who render services wholly or predominately to us may receive only restricted units or phantom units, and executives who render services wholly or predominantly to Penn Virginia or PVG may receive only stock options, restricted stock or restricted stock units. Executives who receive Penn Virginia awards are given the opportunity to elect whether to receive those awards in stock options, restricted stock, restricted stock units or a combination of the three, but it is the Penn Virginia Committee's policy that the awards paid in stock options must comprise at least 50% of the value of the awards. See "How Compensation Is Determined—Considerations in Light of Current Economic Conditions" for a discussion regarding valuation of long-term compensation granted with respect to 2008.

How Compensation Is Determined

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

With respect to Messrs. Horton and Page, who manage our coal and natural resource management-related and natural gas midstream-related operations, respectively, and devote substantially all of their business time to us, our Committee has the primary responsibility to assess all factors relevant to their compensation. Based on that assessment and after discussing such assessment with the PVG Committee, our Committee recommends to the Penn Virginia Committee salary, annual cash bonus and long-term compensation for them, and the Penn Virginia Committee determines their compensation. With respect to the Shared Executives, including our CEO, the Penn Virginia Committee assesses the factors relevant to their compensation and, after discussing such assessment with our Committee and the PVG Committee, sets the salary, annual cash bonus and long-term compensation for each Shared Executive.

Since all of our NEOs other than our CEO report directly to, and work on a daily basis with, our CEO, our Committee and the Penn Virginia Committee review and discuss with our CEO his evaluation of the performance of each of our other NEOs. The Penn Virginia Committee gives considerable weight to our CEO's evaluations when assessing our other NEOs' performance and determining their compensation, and our Committee gives our CEO's evaluation considerable weight when assessing our other NEOs' performance and the amount of compensation to recommend to the Penn Virginia Committee for the Partnership Executives. The Penn Virginia Committee bases its evaluation of our CEO, and our CEO bases his evaluation of each of our other NEOs, primarily on whether we or Penn Virginia met or exceeded certain quantitative partnership or corporate performance criteria and whether each NEO met or exceeded certain specifically tailored job-related individual performance criteria. All corporate, partnership and individual performance criteria, including those by which our

CEO's performance is measured, are recommended by our CEO and set by the Penn Virginia Committee during the preceding year. These performance criteria and other factors relevant to our NEOs' compensation are described in detail below under the headings "Considerations in Light of Current Economic Conditions," "Peer Benchmarks for the Partnership," "Peer Benchmarks for Penn Virginia," "Partnership, Company and Individual Performance Criteria" and "Performance Criteria and Risk Assessment." The Penn Virginia Committee set the 2009 and 2008 base salaries and 2008-related bonus and long-term compensation awards for each of the Partnership Executives in the amounts our Committee recommended. Since we reimburse Penn Virginia for a portion of the Shared Executives' compensation based on the amount of time they devote to us, our Committee reviews the amount of the Shared Executives' time allocable to us each year and determines whether such time allocations are reasonable in light of the business conducted by us during such year.

Considerations in Light of Current Economic Conditions. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, has historically considered general economic condition, as well as industry-specific and Penn Virginia- or Partnership-specific economic conditions, when setting its compensation policies and making compensation decisions. Given the conditions of the current global financial and credit markets and the likely impact of this and other factors in 2009, the Penn Virginia Committee decided not to raise our NEOs' 2009 salaries at this time even though this may result in the Shared Executives receiving salaries which are below the median of Penn Virginia's peers. The Penn Virginia Committee and our Committee also considered whether, given the significant decline in Penn Virginia's stock price and our unit price in 2008, Penn Virginia or we should value the stock or units used to pay long-term compensation based on the grant date closing price, as Penn Virginia and we have done historically, or in a different manner that would result in the issuance of less shares or units. Our Committee and the Penn Virginia Committee decided to continue to use the grant date closing price valuation method for two reasons. First, this method is consistent with Penn Virginia's and our past and current practices, as well as the past and current practices of each of our respective industries. More importantly, it is also consistent with our and Penn Virginia's philosophy that our NEOs' interests should be aligned with the interests of our unitholders and Penn Virginia's shareholders. Given that philosophy, our Committee and the Penn Virginia Committee believe that it would be unfair to make valuation adjustments for low unit or share prices with respect to current grants when we and Penn Virginia do not intend to reprice or otherwise enhance the value of any previously granted options or other long-term compensation to compensate our NEOs for the value loss of those historical grants.

Peer Benchmarks for the Partnership. In 2008, our Committee engaged BDO Seidman LLP, or BDO Seidman, for the second consecutive year as its independent compensation consultant to assist it in a general review of the compensation packages for our NEOs. BDO Seidman analyzed the base salaries, target bonuses and long-term compensation opportunities of the following peer group comprised of 16 publicly traded limited partnerships, referred to as "our Peer Group," comparable to us based on market capitalization and type and geographic location of operations:

Alliance Resource Partners, L.P.	Hiland Partners, LP
Atlas Pipeline Partners, L.P.	Magellan Midstream Partners, L.P.
Boardwalk Pipeline Partners, LP	Natural Resource Partners L.P.
Copano Energy, L.L.C.	NuStar Energy L.P.
Crosstex Energy, L.P.	ONEOK Partners, L.P.
DCP Midstream Partners, LP	Regency Energy Partners LP
Enbridge Energy Partners, L.P.	Sunoco Logistics Partners L.P.
Energy Transfer Partners, L.P.	TEPPCO Partners, L.P.

BDO Seidman's analysis showed that the total compensation of the Partnership Executives falls between the 50^{th} and 75^{th} percentile of our Peer Group, but that our overall cost of management is significantly lower than that of our Peer Group because we reimburse Penn Virginia for only a portion of the Shared Executives' compensation. During 2008, Penn Virginia also performed an internal analysis of our Peer Group's compensation practices as described in proxy statements and other periodic reports, and Penn Virginia's conclusions were generally consistent with those of BDO Seidman. See "How Compensation Is Determined—Partnership, Company and Individual Performance Criteria" for information regarding the competitive compensation positioning of individual NEOs.

Peer Benchmarks for Penn Virginia. In 2008, the Penn Virginia Committee engaged Hewitt Associates LLC, or Hewitt, for the second consecutive year as its independent compensation consultant to assist it in a general review of the compensation packages for the Shared Executives and the president of Penn Virginia's oil and gas subsidiary. Hewitt studied a peer group which was comprised of the following 16 publicly traded oil and gas companies, referred to as the "Penn Virginia Peer Group," similar to Penn Virginia based on revenues, assets, capitalization, scope of operations and total shareholder return:

Berry Petroleum Company	Parallel Petroleum Corporation
Bill Barrett Corporation	Petrohawk Energy Corporation
Cabot Oil & Gas Corporation	Petroleum Development Corporation
Carrizo Oil & Gas, Inc.	PetroQuest Energy, Inc.
CNX Gas Corporation	Quicksilver Resources Inc.
Delta Petroleum Corporation	Range Resources Corporation
EXCO Resources, Inc.	Southwestern Energy Company
Goodrich Petroleum Corporation	St. Mary Land & Exploration Company

Based on Hewitt's analysis of base salaries, target bonuses and long-term compensation opportunities of the Penn Virginia Peer Group as described in survey data and proxy statements and other periodic reports filed by the Penn Virginia Peer Group, Hewitt concluded that total 2008 compensation opportunities for the Shared Executives and the president of Penn Virginia's oil and gas subsidiary, as a group, were generally near the 50^{th} percentile of the Penn Virginia Peer Group. During 2008, Penn Virginia also performed an internal analysis of the Penn Virginia Peer Group's compensation practices as described in proxy statements and other periodic reports, and its conclusions were generally consistent with those of Hewitt. See "How Compensation Is Determined—Partnership, Company and Individual Performance Criteria" for information regarding the competitive compensation positioning of individual NEOs.

Partnership, Company and Individual Performance Criteria. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, targets the amount of salary, cash bonus and long-term compensation awards for each NEO at approximately the 50th percentile of comparable executives of our peers, in the case of the Partnership Executives, or comparable executives of Penn Virginia's peers, in the case of the Shared Executives. However, given the importance of executive accountability for our and Penn Virginia's performance as well as for individual performance, our Committee, the Penn Virginia Committee and the PVG Committee recognize that compensation for any NEO could exceed such 50th percentile targets, reflecting a reward for exceptional Partnership, Penn Virginia or individual performance, or be lower than such 50th percentile targets, reflecting Partnership, Penn Virginia or individual underperformance.

To measure specific performance, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, uses certain quantitative Partnership and Penn Virginia performance criteria and certain quantitative and qualitative individual performance criteria which measure achievement and contribution to us or Penn Virginia. Our Committee, the Penn Virginia Committee and the PVG Committee believe that these performance criteria for each NEO are focused on factors over which such NEO has some control and which should have a positive effect on our and Penn Virginia's operations and on the price of our common units or Penn Virginia's common stock or PVG's common units. The weight given any one criterion and the mix of criteria included in determining amounts of compensation vary among our NEOs depending on their positions and principal areas of responsibility. The relevance and the relative importance of any of these criteria change from time to time, even within the same year, depending on our and Penn Virginia's strategic objectives, operational needs and general business and regulatory environments. For this reason, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, may change these performance criteria from year to year, may assign an aggregate weight to several performance criteria applicable to a NEO, may consider adding criteria which were not known at the time the original criteria were established, or deleting criteria which became obsolete or unimportant, or may consider all criteria collectively.

Performance Criteria and Risk Assessment. Our Committee and the Penn Virginia Committee believe that the performance criteria used to measure bonus and long-term compensation will incent our NEOs to promote vigorously our and Penn Virginia's short- and long-term financial and operational success without taking excessive risks for several reasons. First, objective goals are set annually based on our, Penn Virginia's and our industries' historical experience and also on board-approved budgets at levels which the Penn Virginia Committee and our CEO believe are achievable without undue risk-taking. More importantly, performance criteria include not only objective measures, which alone might promote undue risk-taking to achieve a merely numerical goal, but also subjective measures, which are designed and recommended by our CEO and approved by the Penn Virginia Committee to encourage our NEOs to take steps to position us and Penn Virginia to take advantage of diversified opportunities rather than simply focus on numerical goals. These subjective measures, along with the general discretion the Penn Virginia Committee retains to change the mix or relative importance of criteria from time to time, provide the Penn Virginia Committee and our Committee the tools to evaluate those steps by any measure, including risk-taking, which is assessed on an ongoing basis by the board of directors of our general partner and Penn Virginia's board of directors.

Compensation of Our NEOs

A. James Dearlove, CEO. In February 2009, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, decided not to increase Mr. Dearlove's base salary for 2009, maintaining it at $450,000. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, also awarded to Mr. Dearlove a 2008-related cash bonus of $495,000, or approximately 110% of his 2008 base salary, and a 2008-related long-term compensation award valued at $2,000,000, or approximately 444% of his 2008 base salary, based on the 2008-related performance criteria described below. We reimbursed Penn Virginia for 40% of Mr. Dearlove's 2008-related bonus and long-term compensation awards, or $198,000 and $800,000.

CORPORATE AND PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Increase in our distributable cash flow (DCF) per unit from December 31, 2007 to December 31, 2008 (1)	Target – $1.98 DCF per unit Stretch – $2.06 DCF per unit	Actual – $2.00 DCF per unit
Increase in Penn Virginia's net asset value per share from December 31, 2007 to December 31, 2008 (2)	Target – 13% increase Stretch – 15.6% increase	Actual – 18% increase

INDIVIDUAL CRITERIA	ASSESSMENT
Continually assess and modify our, Penn Virginia's and PVG's strategy as needed to accommodate changes in energy, economic and political environments	Principal architect of our, Penn Virginia's and PVG's individual and collective strategies as presented to the board of directors of our general partner, Penn Virginia's board of directors and the board of directors of PVG's general partner Recommended and oversaw modifications and redirections in our and Penn Virginia's capital spending and other modifications to our and Penn Virginia's strategies resulting from adverse global financial and credit conditions Promoted our strategy to grow coal reserves and other natural resource assets by overseeing two acquisitions, or the "PVR Coal Acquisitions," of aggregate of $26.5 million of coal reserves and timber Promoted our strategy to expand natural gas midstream operations by overseeing five acquisitions, or the "Midstream Acquisitions," by our natural gas midstream division, or PVR Midstream, of aggregate of over $250 million of midstream assets which geographically expanded our gas gathering and processing footprint
Oversee program to sustain long-term oil and natural gas production and reserve growth, adjusting portfolio as necessary	Oversaw spending of $505 million for development and exploratory drilling in 2008, and oversaw redirection of East Texas drilling from Cotton Valley to Bossier Shale and sale of $32 million of non-core oil and gas assets
Assess and modify our business plan and priorities as needed	Altered capital expenditures to adjust for deteriorating market conditions
Evaluate feasibility of PVG participation in our growth	Recognized advantage of and oversaw including PVG units as compensation component to facilitate completion of $165 million PVR Midstream acquisition
Develop synergies between Penn Virginia's oil and gas business and our midstream business	Promoted both our and Penn Virginia's strategy to utilize our relationship with each other by overseeing continuation of our gathering and processing of Penn Virginia's gas through our East Texas gas processing plant and marketing such gas, or, together, the "PVA/PVR Transactions"
Work with Penn Virginia's board of directors to update current succession plan for CEO position and implement personnel evaluation and development plan for us and Penn Virginia	Succession plan and internal candidate assessments reviewed with Penn Virginia's board of directors on annual and as-needed basis and implementation of personnel evaluation and development plan completed
Represent us, Penn Virginia and PVG to investment community	Oversaw active investor relations program, including eight quarterly public teleconferences and 16 investor conferences, including more than 140 "one-on-one" investor meetings, four sales force presentations and seven road shows held during 2008
Ensure ethical "tone at the top" regarding compliance by us, Penn Virginia and PVG with all applicable laws, rules and regulations	We, Penn Virginia and PVG have excellent regulatory and ethical track records

Other considerations	Penn Virginia's 2008 total shareholder return was above median of Peer Group Significant complexity of managing three separate publicly traded entities engaged in multiple businesses

(1) "Distributable cash flow per unit," as we and Penn Virginia compute it, is equal to (x) our distributable cash flow net of our general partner's interest (including IDRs), divided by (y) the weighted average number of our common units issued and outstanding for the year. "Distributable cash flow," as we and Penn Virginia compute it, is equal to (x) the sum of our (A) net income plus (B) DD&A expenses plus (C) impairments plus (D) derivative losses (gains) included in operating income and other income plus (E) cash received (paid) for derivative settlements plus (F) cash received from equity method joint ventures, minus (y) the sum of our (A) equity earnings from joint ventures plus (B) maintenance capital expenditures.

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

The Penn Virginia Committee believes, and Hewitt's data confirmed, that the amounts of 2008-related bonus and long-term compensation awarded to Mr. Dearlove, when combined with his base salary, comprise an industry-competitive compensation package that falls slightly above the 50th percentile of CEOs in the Penn Virginia Peer Group. Further, the Penn Virginia Committee believes that this compensation appropriately reflects our, Penn Virginia's and Mr. Dearlove's 2008 performances. Our Committee reviewed Mr. Dearlove's time allocated to us during 2008 and concluded that such allocation was reasonable given the business conducted by us during 2008.

Frank A. Pici, Vice President and CFO. In February 2009, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, decided not to increase Mr. Pici's base salary for 2009, maintaining it at $275,000. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, also awarded to Mr. Pici a 2008-related cash bonus of $210,000, or approximately 76% of his 2008 base salary, and a 2008-related long-term compensation award valued at $550,000, or approximately 200% of his 2008 base salary, based on the 2008-related performance criteria described below. We reimbursed Penn Virginia for 33% of Mr. Pici's 2008-related cash bonus and long-term compensation awards, or $69,300 and $181,500.

CORPORATE AND PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Increase in our distributable cash flow (DCF) per unit from December 31, 2007 to December 31, 2008 (1)	Target – $1.98 DCF per unit Stretch – $2.06 DCF per unit	Actual – $2.00 DCF per unit
Increase in Penn Virginia's net asset value per share from December 31, 2007 to December 31, 2008 (2)	Target – 13% increase Stretch – 15.6% increase	Actual – 18% increase

INDIVIDUAL CRITERIA	ASSESSMENT
Evaluate feasibility of tax efficient redeployment of certain of Penn Virginia's assets	Oversaw evaluations of potential redeployment of certain groups of assets, including sale of $32 million of non-core oil and gas assets
Evaluate Penn Virginia's capital structure and need for additional financing	Oversaw continuing evaluation of capital structure
Oversee manner and timing of additional financing for us	Oversaw $153 million Partnership follow-on offering, or the "PVR Offering," $700 million Partnership refinancing and conversion to secured credit facility, or the "PVR Refinancing," and prepayment of our senior notes
Identify and analyze techniques whereby PVG assists us in making acquisitions	Identified PVG-related financing alternatives for us and recognized advantage of including PVG units as compensation component in $165 million PVR Midstream acquisition
Oversee financial planning, modeling and evaluation of potential acquisitions by us and Penn Virginia	Participated in strategic and economic evaluations of PVR Coal Acquisitions and Midstream Acquisitions and oversaw financial planning
Monitor hedging policy for our natural gas midstream business and Penn Virginia's oil and gas exploration and production business and set policy for SOX compliance	Current hedging policies for PVR Midstream's and Penn Virginia's businesses in place and monitored regularly SOX compliance policies in place, and we, Penn Virginia and PVG have had no significant SOX-related regulatory compliance issues
Develop succession plan for the position of CFO	Assessment of internal candidates reviewed with CEO annually
Work with HR department to develop personnel evaluation methodology for finance and accounting staff	Evaluation methodology completed and in use

Overall responsibility for finance, accounting, tax, audits, investor relations and information technology	Transition to new accounting system not completed within expected time period, but in final stages of full implementation
	Excellent relationship with our and Penn Virginia's bank groups comprised of 17 banks and 10 banks
	Oversaw active investor relations function
Other considerations	Penn Virginia's 2008 total shareholder return was above median of Peer Group
	Significant complexity of managing finance, tax, accounting, treasury, investor relations and information technology-related aspects of three separate publicly traded entities engaged in multiple businesses

The Penn Virginia Committee believes, and Hewitt's data confirmed, that the amounts of 2008-related bonus and long-term compensation awarded to Mr. Pici, when combined with his base salary, comprise an industry-competitive compensation package that falls between the 25th and the 50th percentiles of CFOs in the Penn Virginia Peer Group. Further, the Penn Virginia Committee believes that this compensation appropriately reflects our, Penn Virginia's and Mr. Pici's 2008 performances. Our Committee reviewed Mr. Pici's time allocated to us during 2008 and concluded that such allocation was reasonable given the business conducted by us during 2008.

Nancy M. Snyder, Vice President, Chief Administrative Officer and General Counsel. In February 2009, the Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, decided not to increase Ms. Snyder's base salary for 2009, maintaining it at $265,000. The Penn Virginia Committee, with the assistance of our Committee and the PVG Committee, also awarded to Ms. Snyder a 2008-related cash bonus of $235,000, or approximately 89% of her 2008 base salary, and a 2008-related long-term compensation award valued at $850,000, or approximately 321% of her 2008 base salary, based on the 2008-related performance criteria described below. We reimbursed Penn Virginia for 35% of Ms. Snyder's 2008-related cash bonus and long-term compensation awards, or $82,250 and $297,500.

CORPORATE AND PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Increase in our distributable cash flow (DCF) per unit from December 31, 2007 to December 31, 2008 (1)	Target – $1.98 DCF per unit Stretch – $2.06 DCF per unit	Actual – $2.00 DCF per unit
Increase in Penn Virginia's net asset value per share from December 31, 2007 to December 31, 2008 (2)	Target – 13% increase Stretch – 15.6% increase	Actual – 18% increase

INDIVIDUAL CRITERIA	ASSESSMENT
Assist in determining our, Penn Virginia's and PVG's direction from both a legal and business perspective and participate in business and strategic decisions	Contributed to formulation of our, Penn Virginia's and PVG's individual and collective strategy in general and with respect to all transactions described below
Oversee negotiation of issues related to our and Penn Virginia's acquisitions, dispositions, public offerings and other transactions from both a legal and business perspective	Oversaw negotiation of PVR Offering, PVA/PVR Transactions, PVR Coal Acquisitions, Midstream Acquisitions, PVR Refinancing and other transactions
	All PVA/PVR Transactions and PVR Coal Acquisitions, and several PVR Midstream Acquisitions, completed in-house with outside counsel retained only with respect to local title opinions or advice related to specialties such as tax and local environmental matters
Facilitate efficiency of transactions between us and Penn Virginia	PVA/PVR Transactions accomplished and potential conflicts identified and resolved
Advise and assist other officers of our general partner, Penn Virginia and PVG's general partner regarding day-to-day legal matters, including those related to banking, insurance and financing	Oversaw in-house completion of several credit agreement amendments for us and Penn Virginia, numerous acquisition bids, joint operating agreements, joint exploration agreements, master service agreements, gas processing and transportation agreements, leases, easements and other day-to-day transactions and renewal of our, Penn Virginia's and PVG's directors and officers liability and other insurance policies
Oversee regulatory compliance and governance requirements for us, Penn Virginia and PVG	We, Penn Virginia and PVG have excellent legal compliance track record
	Monitored and reacted in timely manner to changes in laws, rules

	and regulations
	Reviewed and suggested amendment, as necessary, of all governance and other documents, including committee charters, codes of conduct, whistleblower policies, trading policies and equity plans for us, Penn Virginia and PVG
Oversee outside legal counsel, in-house legal staff and corporate secretary function	Directed outside counsel with respect to PVR Offering and PVR Refinancing and oversaw all outside litigation or dispute-related work
	Oversaw in-house legal staff, which, in addition to transactional work and day-to-day contractual matters, reviewed or prepared our, Penn Virginia's and PVG's periodic filings and governance documents, including more than 37 Form 8-Ks, 70 sets of board and committee minutes and 204 Form 4s
Overall responsibility of human resources function for us and Penn Virginia	Continued to expand and improve structure and efficiency of human resource department
	Oversaw continuation of compensation peer group analyses
Review and recommend modifications as necessary to our and Penn Virginia's compensation policies	Created potential new Partnership compensation vehicle for consideration by our Committee
Develop personnel evaluation methodology for us and Penn Virginia	Personnel evaluation methodology developed
Develop succession plan for general counsel position	Assessment of internal candidates reviewed with CEO annually
Other considerations	Good ability to select and manage personnel
	Penn Virginia's 2008 total shareholder return was above median of Peer Group
	Significant complexity of managing legal, human resource and corporate secretary functions of three separate publicly traded entities engaged in multiple businesses

The Penn Virginia Committee believes, and Hewitt's data confirmed, that the amounts of 2008-related bonus and long-term compensation awarded to Ms. Snyder, when combined with her base salary, comprise an industry-competitive compensation package that falls at approximately the 50th percentile of officers in the Penn Virginia Peer Group who have responsibilities comparable to those of Ms. Snyder. Further, the Penn Virginia Committee believes that this compensation appropriately reflects our, Penn Virginia's and Ms. Snyder's 2008 performances. Our Committee reviewed Ms. Snyder's time allocated to us during 2008 and concluded that such allocation was reasonable given the business conducted by us during 2008.

Keith D. Horton, Chief Operating Officer—Coal. In February 2009, our Committee, with the assistance of the PVG Committee, recommended and the Penn Virginia Committee decided not to increase Mr. Horton's base salary for 2009, maintaining it at $280,000. Our Committee, with the assistance of the PVG Committee, also recommended and the Penn Virginia Committee, with the concurrence of our Committee, awarded to Mr. Horton a 2008-related cash bonus of $160,000, or approximately 57% of his 2008 base salary, and a 2008-related long-term compensation award valued at $420,000, or approximately 150% of his 2008 base salary, based on the 2008-related performance criteria described below. We paid all of Mr. Horton's 2008-related bonus and long-term compensation awards.

PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Increase in our coal and natural resource management-related EBITDA from December 31, 2007 to December 31, 2008	Target – $99 million of EBITDA Stretch – $104 million of EBITDA	Actual – $127.1 million of EBITDA
Increase in our coal reserves from December 31, 2007 to December 31, 2008	Target – 100 million ton increase Stretch – 150 million ton increase	Actual – 25 million ton increase
Increase in our revenues from coal infrastructure assets from December 31, 2007 to December 31, 2008	Target – $7.8 million of revenues Stretch – $8.5 million of revenues	Actual – $7.4 million of revenues
INDIVIDUAL CRITERIA	**ASSESSMENT**	
Evaluate importance of and, if appropriate, develop three- and	Evaluations completed and long-range plans to grow timber	

five-year plans to grow, non-coal assets, including timber assets	developed
Develop a succession plan	Assessment of internal candidates reviewed with CEO annually
Develop a personnel evaluation methodology for coal and timber employees	Development of methodology in process
Other considerations	We increased distributions by 9.6% during 2008

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

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

Ronald K. Page, Chief Operating Officer—Midstream. In February 2009, our Committee, with the assistance of the PVG Committee, recommended and the Penn Virginia Committee decided not to increase Mr. Page's base salary for 2009, maintaining it at $260,000. Our Committee, with the assistance of the PVG Committee, also recommended and the Penn Virginia Committee, with the concurrence of our Committee, awarded to Mr. Page a 2008-related cash bonus of $160,000, or approximately 62% of his 2008 base salary, and a 2008-related long-term compensation award valued at $440,000, or approximately 169% of his 2008 base salary, based on the 2008-related performance criteria described below. We paid all of Mr. Page's 2008-related bonus and long-term compensation awards.

PARTNERSHIP CRITERIA	GOAL	PERFORMANCE
Increase in our natural gas midstream-related EBITDA from December 31, 2007 to December 31, 2008	Target – $64.5 million of EBITDA Stretch – $70 million of EBITDA	Actual – $78.1 million of EBITDA
INDIVIDUAL CRITERIA	**ASSESSMENT**	
Make Spearman plant operational by March 2008 and make Crossroads plant operational by April 2008	Each plant one month late	
Expand size and reach of existing facilities	Size and reach of existing facilities expanded	
Develop and execute plan to gather third party gas at Crossroads plant	Several plans formulated and continuing to be refined – plant has processed third party gas	
Identify and complete $50 million of gathering and processing acquisitions	Completed over $250 million of acquisitions in 2008	
Evaluate acquisition of non-depleting assets	Almost all newly acquired assets contracted on fee-based basis	
Develop a succession plan	Succession plan developed and assessment of internal candidates reviewed with CEO annually	
Develop a personnel evaluation for midstream employees	Evaluation completed and time and effort spent to develop personnel	
Other considerations	We increased distributions by 9.6% during 2008	

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

Our Committee and the Penn Virginia Committee believe, and BDO Seidman's review and interpretation of market data confirmed, that the amounts of 2008-related bonus and long-term compensation awarded to Mr. Page, when combined with his base salary, comprise an industry-competitive compensation package that falls between the 50th and 75th percentiles of chief operating officers in our Peer Group. Further, our Committee and the Penn Virginia Committee believe that this compensation appropriately reflects our and Mr. Page's 2008 performances. These amounts also reflect Mr. Page's strong leadership abilities, significant industry experience and our desire to retain his services, as well as our Committee's and the Penn Virginia Committee's desire to facilitate, to the extent reasonable and appropriate, the opportunity for all of our NEOs to earn reasonably comparable compensation notwithstanding that they work in different industries that have different compensation practices.

Compensation Committee Report

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

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

Compensation and Benefits Committee

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

Summary Compensation Table

The following table sets forth the compensation paid by us, during or with respect to the years ended December 31, 2008, 2007 and 2006, to our CEO, our CFO and our general partner's three other most highly compensated executive officers for services rendered to us and our subsidiaries:

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) (1)	All Other Compensation ($) (2)	Total ($)
A. James Dearlove	2008	180,000	198,000	425,509	15,152	818,661
Chief Executive Officer	2007	144,400	209,000	257,859	13,709	624,968
	2006	183,500	185,000	253,348	17,773	639,621
Frank A. Pici	2008	90,750	69,300	169,203	12,060	341,313
Vice President and	2007	73,640	61,600	136,006	9,296	280,542
Chief Financial Officer	2006	80,960	65,600	125,175	9,838	281,573
Keith D. Horton	2008	280,000	160,000	346,216	35,415	821,631
Co-President and Chief	2007	270,000	185,000	279,457	31,800	766,257
Operating Officer—Coal	2006	260,000	182,000	261,957	30,100	734,057
Ronald K. Page	2008	260,000	160,000	300,551	35,200	755,751
Co-President and Chief	2007	235,000	170,000	225,828	31,800	662,628
Operating Officer—Midstream	2006	220,000	150,000	151,644	30,100	551,744
Nancy M. Snyder	2008	92,750	82,250	175,193	12,694	362,887
Vice President, Chief Administrative	2007	75,900	70,950	124,830	10,494	282,174
Officer and General Counsel	2006	94,600	77,400	110,444	13,425	295,869

(1) Represents the amounts of expense recognized by us in 2008, 2007 and 2006 for financial statement reporting purposes with respect to restricted units previously granted by our Committee to our NEOs in consideration for services rendered to us. These amounts were computed in accordance with SFAS No. 123(R), *Share-Based Payment*, and were based on the NYSE closing prices of our common units on the dates of grant. See Note 16 in the Notes to Consolidated Financial

Statements.

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

The cash components of our executive compensation consist of a base salary and the opportunity to earn an annual cash bonus. See "Compensation Discussion and Analysis—Elements of Compensation." The amounts of salary and bonus reflected in the Summary Compensation Table above include only amounts paid or reimbursed by us in consideration for services rendered to us by our NEOs and do not include any amounts paid by Penn Virginia to any of our NEOs in consideration for services rendered to Penn Virginia. The specific portions of salary and bonus paid, or reimbursed to Penn Virginia, by us depend on the portion of professional time devoted by each NEO to us. See "Compensation and Discussion Analysis—Compensation Structure" for a description of the manner in which our NEOs are compensated. The following table shows the portion of professional time devoted to us by each Shared Executive in 2008, 2007 and 2006 and the portion of such Shared Executive's salary and bonus we reimbursed Penn Virginia with respect to those years:

	PVR Portion		
Shared Executive	**2008**	**2007**	**2006**
A. James Dearlove	40%	38%	50%
Frank A. Pici	33%	28%	32%
Nancy M. Snyder	35%	33%	43%

Because each of the Partnership Executives devoted all of his professional time to us in 2008, 2007 and 2006, we paid all of his 2008, 2007 and 2006 salaries and 2008-related, 2007-related and 2006-related bonuses. For a discussion of the salaries and bonuses paid to the Shared Executives by Penn Virginia, see the Penn Virginia Proxy Statement relating to its 2009 Annual Meeting of Shareholders.

The equity components of our executive compensation program consist of the opportunity to earn awards of restricted units or phantom units from us and awards of stock options, restricted stock and restricted stock units from Penn Virginia. Like the cash component of executive compensation, that portion of the value of each NEO's equity-based compensation paid or reimbursed by us depends on the portion of professional time that each NEO devotes to us. The values of the stock awards reflected in the Summary Compensation Table above include only the values of restricted unit awards granted by our Committee. Our Committee did not grant any phantom units in 2008, 2007 or 2006.

Grants of Plan-Based Awards

The following table sets forth the grant date and number of all restricted units granted to our NEOs in 2008 by our Committee with respect to services rendered to us in 2007:

2008 Grants of Plan-Based Awards

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards ($)
A. James Dearlove	February 22, 2008	28,242	759,992
Frank A. Pici	February 22, 2008	8,324	223,999
Keith D. Horton	February 22, 2008	14,864	399,990
Ronald K. Page	February 22, 2008	14,864	399,990
Nancy M. Snyder	February 22, 2008	9,810	263,987

The values of our restricted units were based on the NYSE closing prices of our common units on the dates of grant. All restricted units granted to our NEOs since 2005 vest over a three-year period, with one-third of each award vesting on the first, second and third anniversaries of the grant date unless (i) the restricted unitholder's employment terminates for any reason other than death or retirement as provided in (ii) below, in which event any unvested restricted units are forfeited unless otherwise determined by our Committee, or (ii) the restricted unitholder dies or retires after reaching age 62 and completing 10 years of consecutive service with our general partner or its affiliate or there occurs a change of control, in which events all restrictions lapse.

Our Committee granted phantom units to our NEOs for the first time in February 2009. Each phantom unit so granted entitles the grantee to receive one common unit upon vesting, which occurs over a three-year period, with one-third of each award vesting on the first, second and third anniversaries of the grant date unless (i) the phantom unitholder's employment terminates for any reason other than death or disability, in which event any unvested phantom units are forfeited unless otherwise determined by our Committee, or (ii) the phantom unitholder dies, becomes disabled or becomes retirement eligible, which is defined as reaching age 62 and completing 10 years of consecutive service with our general partner or its affiliate, or there occurs a change of control, in which events all restrictions lapse. Payments of the phantom unit awards granted in February 2009 will be made in common units (or, at the request of the phantom unitholder and upon the approval of our Committee, an amount of cash equal to the fair market value of our common units) at the time of vesting, unless vesting occurs early on account of becoming retirement eligible, in which event payments will be made when such phantom units would have originally vested, even if that is after retirement. Our Committee granted distribution equivalent rights in tandem with the phantom unit awards it granted in February 2009.

Our Committee grants annual compensation-based restricted units or phantom units during the first quarter of each year after the Penn Virginia Committee, with our Committee's and the PVG Committee's assistance, has concluded its analysis of executive compensation with respect to the preceding year. Our Committee also grants restricted units from time to time in connection with the hiring of new Partnership-related employees and, while it has not done so, may consider such grants in connection with promotions. To date, our Committee has not granted any phantom units in connection with the hiring of new employees or in connection with promotions, but it may consider such grants in the future. Our Committee may also consider grants at such other times as it may deem appropriate.

During 2008, we paid quarterly distributions ranging from $0.44 to $0.47 on each restricted unit. The distributions were paid at the same times and in the same amounts as distributions paid to the other holders of our common units and were taken into consideration when determining the values of the restricted units shown previously in the Summary Compensation Table and in the Grants of Plan-Based Awards Table above.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information regarding the numbers and values of restricted units not vested as of December 31, 2008 held by our NEOs on December 31, 2008. The market value of non-vested restricted units is based on the NYSE closing price of our common units on December 31, 2008.

Outstanding Equity Awards at Fiscal Year-End 2008

	Stock Awards	
Name	**Number of Shares or Units of Stock That Have Not Vested (#)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)**
A. James Dearlove	39,357 (1)	447,489
Frank A. Pici	13,373 (2)	152,051
Keith D. Horton	26,721 (3)	303,818
Ronald K. Page	24,558 (4)	279,224
Nancy M. Snyder	14,945 (5)	169,925

(1) Of these restricted units, 9,414 vested on February 22, 2009, 7,236 will vest on February 27, 2009, 9,414 will vest on February 22, 2010, 3,879 will vest on February 27, 2010 and 9,414 will vest on February 22, 2011.
(2) Of these restricted units, 2,775 vested on February 22, 2009, 3,540 will vest on February 27, 2009, 2,775 will vest on February 22, 2010, 1,509 will vest on February 27, 2010 and 2,774 will vest on February 22, 2011.
(3) Of these restricted units, 4,955 vested on February 22, 2009, 7,947 will vest on February 27, 2009, 4,955 will vest on February 22, 2010, 3,910 will vest on February 27, 2010 and 4,954 will vest on February 22, 2011.
(4) Of these restricted units, 4,955 vested on February 22, 2009, 6,404 will vest on February 27, 2009, 4,955 will vest on February 22, 2010, 3,290 will vest on February 27, 2010 and 4,954 will vest on February 22, 2011.
(5) Of these restricted units, 3,270 vested on February 22, 2009, 3,415 will vest on February 27, 2009, 3,270 will vest on February 22, 2010, 1,720 will vest on February 27, 2010 and 3,270 will vest on February 22, 2011.

Vesting of Restricted Units

The following table sets forth the number of common units acquired, and the values realized, by our NEOs upon the vesting of restricted units during 2008:

Option Exercises and Stock Vested in 2008

	Stock Awards	
Name	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
A. James Dearlove	10,154	276,972
Frank A. Pici	5,256	143,367
Keith D. Horton	10,913	297,677
Ronald K. Page	8,856	241,567
Nancy M. Snyder	4,887	133,303

Nonqualified Deferred Compensation

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

2008 Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($) (1)	Registrant Contributions in Last FY ($)	Aggregate Earnings (Loss) in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($) (2)
A. James Dearlove	275,000	0	(176,853)	0	763,535
Frank A. Pici	110,000	0	(623,779)	0	1,170,084
Keith D. Horton	0	0	(8,213)	0	11,083
Ronald K. Page	1,500	0	(40,391)	0	60,475
Nancy M. Snyder	185,000	0	(391,540)	0	880,988

(1) All of these amounts are included in the amounts of salary and bonus for 2008 reported by us or Penn Virginia in the Summary Compensation Tables included in this Annual Report on Form 10-K and Penn Virginia's Proxy Statement relating to its 2009 Annual Meeting of Shareholders.

(2) Except with respect to aggregate contributions by Penn Virginia of $21,910 on behalf of Mr. Pici in 2001 and 2002, these amounts reflect only salaries and bonuses paid to our NEOs and earnings on those salaries and bonuses. All such salary and bonus amounts were previously reported by us or Penn Virginia as compensation to our NEOs in the Summary Compensation Tables included in our Annual Reports on Form 10-K and Penn Virginia's Proxy Statements.

The Penn Virginia Corporation Supplemental Employee Retirement Plan, or the SERP, allows all of Penn Virginia's and its affiliates' employees, including employees of our general partner, whose salaries exceeded $130,000 in 2008 to defer receipt of up to 100% of their salary, net of their salary deferrals under Penn Virginia's 401(k) Plan, and up to 100% of their annual cash bonuses. The amounts reported in the Nonqualified Deferred Compensation Table above include not only contributions and earnings thereon related to deferred salaries and bonuses paid for services rendered to us, but also contributions and earnings thereon related to deferred salaries and bonuses paid for services rendered to Penn Virginia. All deferrals under the SERP are credited to an account maintained by Penn Virginia and are invested by Penn Virginia, at the employee's election, in Penn Virginia's common stock or in certain mutual funds made available by Penn Virginia and selected by the employee. Since all amounts deferred under the SERP consist of previously earned salary or bonus, all SERP participants are fully vested at all times in all amounts credited to their accounts. Amounts held in a participant's account will be distributed to the participant on the earlier of the date on which such participant's employment terminates or there occurs a change of control of Penn Virginia. Neither we nor Penn Virginia are required to make any contributions to the SERP. Since Penn Virginia established the SERP in 1996, it has contributed an aggregate of $43,816 in 2001 and 2002 to the SERP in connection with offers of employment to Mr. Pici and another executive of Penn Virginia, but has made no other contributions to the SERP.

Penn Virginia has established a rabbi trust to fund the benefits payable under the SERP. Other than the $43,816 of Penn Virginia contributions described above, the assets of the rabbi trust consist of the cash amounts of salary and bonus already earned and deferred by our NEOs and other employees under the SERP and the securities in which those amounts have been invested. Assets held in the rabbi trust are designated for the payment of benefits under the SERP and are not available for Penn Virginia's general use. However, the assets held in the rabbi trust are subject to the claims of Penn Virginia's general creditors, and SERP participants may not be paid in the event of Penn Virginia's insolvency.

Long-Term Incentive Plan

Our general partner has adopted the Penn Virginia Resource GP, LLC Fifth Amended and Restated Long-Term Incentive Plan, or our LTIP. Our LTIP permits 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 our LTIP can be in the form of common units, restricted units, unit options, phantom units and deferred common units. Our LTIP is administered by our Committee.

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

Common Units. Our LTIP permits the grant of common units to employees and directors. Our general partner granted 1,525 common units to a director of our general partner in 2008.

Restricted Units. Our LTIP permits the grant of restricted units to employees and directors. Our general partner granted 135,251 restricted units to officers and employees of our general partner in 2008. Restricted units vest upon terms established by our Committee. In addition, all restricted units will vest upon a change of control. 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 unvested restricted units will be automatically forfeited unless, and to the extent, that our Committee provides otherwise. 2,253 restricted units were forfeited in 2008. Distributions payable with respect to restricted units may, in our Committee's discretion, be paid directly to the grantee or held by our general partner and made subject to a risk of forfeiture during the applicable restriction period.

Unit Options. Our LTIP permits the grant of options covering common units to employees and directors. No grants of unit options have been made under our LTIP. Unit options will have an exercise price that is determined by our Committee, but may not be less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by our Committee. In addition, all unit options will become exercisable upon a change of control. 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 unit options will be automatically forfeited unless, and to the extent, that our Committee provides otherwise. Upon exercise of a unit option, our general partner will acquire common units in the open market or directly from us or any other person or use common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring these common units and the proceeds received by our general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us.

Phantom Units. Our LTIP permits the grant of phantom units to employees and directors. No grants of phantom units were made under our LTIP in 2008. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of our Committee, the cash equivalent of the value of a common unit. Our Committee will determine the time period over which phantom units granted to employees and directors will vest. In addition, all phantom units will vest upon a change of control. 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, our Committee provides otherwise. Common units delivered upon the vesting of phantom units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. Our Committee, in its discretion, may grant tandem distribution equivalent rights with respect to phantom units.

Deferred Common Units. Our LTIP permits the grant of deferred common units to directors. Our general partner granted 21,337 deferred common units to directors of our general partner in 2008. Each deferred common unit represents one common unit, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of our general partner. Common units delivered in connection with deferred common units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. Deferred common units awarded to directors receive additional deferred common units equal in value to all cash or other distributions paid by us on account of our common units.

Change-in-Control Arrangements

Our Committee, the Penn Virginia Committee, we and Penn Virginia believe that the Partnership Executives, together with our other senior management and key employees, are a primary reason for our success and that it is important for us to protect them in the event that they lose their jobs under certain circumstances upon a change of control. Four of our five NEOs are age 55 or older, and our NEOs have served the Partnership or Penn Virginia for an average of more than 15 years, with Messrs. Dearlove and Horton and Ms. Snyder having served in various capacities for 31, 26 and 11 years. We and Penn Virginia also believe that, by providing change of control protection, our NEOs will be able to evaluate every Partnership or Penn Virginia opportunity, including a change of control, that may likely result in the termination of their employment, without the distraction of personal considerations. For these reasons, our general partner has entered into change of control severance agreements with the Partnership Executives, which entitle them to the benefits described below and which are substantially the same as the change of control severance agreements entered into between Penn Virginia and each of the Shared Executives. We and Penn Virginia have studied the executive severance arrangements of our Peer Group and the Penn Virginia Peer Group, as described in their 2008 proxy statements and 2007 annual reports on Form 10-K, and found that the terms of our and Penn Virginia's change of control severance agreements are comparable to those of our and Penn Virginia's peers.

General Partner Executive Change of Control Severance Agreements

On October 17, 2008, our general partner entered into an Amended and Restated Executive Change of Control Severance Agreement, or a General Partner Severance Agreement, with each of Messrs. Horton and Page containing the terms and conditions described below.

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

Triggering Events. Each General Partner Severance Agreement provides severance benefits to the Partnership Executive upon the occurrence of two events, or the GP Dual Triggering Events. Specifically, if a change of control occurs and, within two years after the date of such change of control, either (a) our general partner terminates the Partnership Executive's employment for any reason other than for cause or the Partnership Executive's inability to perform his duties for at least 180 days due to mental or physical impairment or (b) the Partnership Executive terminates his employment due to a material reduction in his authority, duties, title, status or responsibility, a greater than 5% reduction in his base salary, a discontinuation of a material incentive compensation plan in which he participated, the failure of our general partner to obtain an agreement from its successor to assume his General Partner Severance Agreement or his relocation by more than 100 miles of the office of our general partner at which he was working at the time of the change of control, then the Partnership Executive may elect to receive the change of control severance payments and other benefits described below.

Change of Control Severance Benefits. Upon the occurrence of the GP Dual Triggering Events, the Partnership Executive may elect to receive a lump sum, in cash, of an amount equal to three times the sum of his annual base salary plus the highest cash bonus paid to him during the two-year period prior to termination, subject to reduction as described below under "Excise Taxes." In addition, all options to purchase shares of Penn Virginia common stock then held by the Partnership Executive will immediately vest and will remain exercisable for the shorter of three years or the remainder of the options' respective terms and all restricted Penn Virginia stock and all restricted units of PVR and PVG then held by the Partnership Executive will immediately vest and all restrictions will lapse. Our general partner will also provide certain health and dental benefit-related payments to the Partnership Executive as well as certain outplacement services.

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

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

Estimated Payments

The following table sets forth the estimated aggregate payments to Messrs. Horton and Page under their respective General Partner Severance Agreements assuming that the GP Dual Triggering Events occurred on December 31, 2008:

Name of Executive Officer	Salary and Bonus ($)	Accelerated Vesting of Restricted Stock and Units ($)	Other Benefits ($) (1)	Total Estimated Severance Payment ($)
Keith D. Horton	1,395,000	303,829	81,400	1,780,229
Ronald K. Page	1,290,000	279,224	81,400	1,650,624

(1) Other benefits include medical and dental insurance-related payments and the value of outplacement services.

Penn Virginia Executive Change of Control Severance Agreements

On October 17, 2008, Penn Virginia entered into an Amended and Restated Executive Change of Control Severance Agreement, or a Penn Virginia Severance Agreement, with each of the Shared Executives containing terms and conditions substantially similar to those of the General Partner Severance Agreements. For a discussion of the terms and conditions of, and the estimated payments under, the Penn Virginia Severance Agreements, see the Penn Virginia Proxy Statement relating to its 2009 Annual Meeting of Shareholders. Any payments required to be made to the Shared Executives under the Penn Virginia Severance Agreements will be the sole responsibility of Penn Virginia.

Compensation of Directors

The following table sets forth the aggregate compensation paid by us to the non-employee directors of our general partner during 2008:

2008 Director Compensation

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($) (1)	Total ($)
Edward B. Cloues, II	35,000	90,000 (2)	125,000
John P. DesBarres	0 (3)	150,000 (4)	150,000
James L. Gardner	55,500	90,000 (5)	145,500
James R. Montague	57,500	90,000 (6)	147,500
Marsha R. Perelman	0 (7)	121,000 (8)	121,000

(1) Represents the amounts of expense recognized by us in 2008 for financial statement reporting purposes with respect to the common units and deferred common units previously granted to the non-employee directors of our general partner. These amounts were computed in accordance with SFAS No. 123(R) and are based on the NYSE closing price of our common units on the dates of grant. See Note 16 in the Notes to Consolidated Financial Statements.

(2) As of December 31, 2008, Mr. Cloues had 15,093 deferred common units outstanding.

(3) Mr. DesBarres elected to receive all cash fees in deferred common units.
(4) Mr. DesBarres died in December 2008. As of December 31, 2008, Mr. DesBarres had no deferred common units outstanding.
(5) As of December 31, 2008, Mr. Gardner had 10,640 deferred common units outstanding.
(6) As of December 31, 2008, Mr. Montague had 15,093 deferred common units outstanding.
(7) Ms. Perelman elected to receive all cash fees in common units.
(8) As of December 31, 2008, Ms. Perelman had 13,607 deferred common units outstanding.

Each non-employee director of our general partner receives an annual retainer of $110,000, consisting of $20,000 of cash and $90,000 worth of deferred common units. The actual number of deferred common units awarded in any given year is based upon the NYSE closing price of our common units on the dates on which such awards are granted. Each deferred common unit represents one common unit representing a limited partner interest in us, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of our general partner. Directors are restricted from selling such common units until six months after such termination or retirement. The Chairman of the audit committee of the board of directors of our general partner receives an annual cash retainer of $15,000, and each audit committee member receives an annual cash retainer of $10,000. The Chairmen of all other committees of the board of directors of our general partner receive annual cash retainers of $2,500. All annual retainers are payable on a quarterly basis. In addition to annual retainers, each non-employee director receives $1,000 cash for each board of directors and committee meeting he or she attends. Directors appointed during a year, or who cease to be directors during a year, receive a pro rata portion of cash and deferred common units. Directors may elect to receive any cash payments in common units or deferred common units, and may elect to defer the receipt of any cash or common units they receive under our general partner's Amended and Restated Non-Employee Directors Deferred Compensation Plan.

Our general partner does not have any unit ownership requirement for its directors.

Non-Employee Directors Deferred Compensation Plan

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

Compensation Committee Interlocks and Insider Participation

During 2008, Messrs. Cloues, Gardner and Montague and John P. DesBarres, who died in December 2008, served on the compensation and benefits committee of our general partner. None of these members is a former or current officer or employee of us or any of our subsidiaries or had any relationship requiring disclosure under Item 404 of Regulation S-K, "Transactions with Related Persons, Promoters and Certain Control Persons." In 2008, none of the executive officers of our general partner served as a member of the board of directors or compensation committee of any entity that has one or more executive officers serving on the board of directors or the compensation and benefits committee of our general partner.

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

Beneficial Ownership of Units

The following table sets forth, as of February 26, 2009, the amount and percentage of our outstanding common units beneficially owned by (i) each person known by us to own beneficially more than 5% of our common units, (ii) each director of our general partner, (iii) each executive officer of our general partner and (iv) all directors and executive officers of our general partner as a group:

Name of Beneficial Owner	Common Units (1)		Percent of Common Units (2)
Penn Virginia GP Holdings, L.P. (3)	19,587,049		37.8%
Penn Virginia Resource GP Corp. (3)	51,333		*
Edward B. Cloues, II	32,810	(4)	*
A. James Dearlove	97,905	(5)	*
James L. Gardner	14,296	(6)	*
Keith D. Horton	66,008	(7)	*
James R. Montague	33,888	(8)	*
Ronald K. Page	28,558	(9)	*
Marsha R. Perelman	28,665	(10)	*
Frank A. Pici	40,093	(11)	*
Nancy M. Snyder	38,942	(12)	*
All directors and executive officers as a group (9 persons)	381,165	(13)	*

* Less than 1%.

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

(2) Based on 51,798,895 common units issued and outstanding on February 26, 2009. On February 26, 2009, there were approximately 29,200 holders of our common units.

(3) Penn Virginia is the ultimate parent company of Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp. As such, Penn Virginia may be deemed to beneficially own the common units held by Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp., which together own 37.9% of our common units. The address for each of Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp. is c/o Penn Virginia Corporation, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087.

(4) Includes 18,888 deferred common units.

(5) Includes 22,707 restricted units.

(6) Reflects 14,296 deferred common units.

(7) Includes 13,819 restricted units and 1,000 common units held by Mr. Horton's spouse.

(8) Includes 2,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan and 18,888 deferred common units.

(9) Includes 13,199 restricted units.

(10) Includes 17,356 deferred common units and 5,000 common units held by a trust of which Ms. Perelman is a trustee and a beneficiary.

(11) Includes 7,058 restricted units.

(12) Includes 8,260 restricted units and 470 common units held by Ms. Snyder for the benefit of a minor child.

(13) Includes 65,043 restricted units, 2,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan, 69,428 deferred common units, 5,000 common units held by a trust of which Ms. Perelman is a trustee and a beneficiary, 1,000 common units held by Mr. Horton's spouse and 470 common units held by Ms. Snyder for the benefit of a minor child.

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2008 regarding the options outstanding and securities issued and to be issued under our general partner's equity compensation plans not approved by our unitholders. Our general partner does not have any equity compensation plans which were approved by our unitholders. See Item 11, "Executive Compensation—Long-Term Incentive Plan," for a description of our LTIP, our only equity compensation plan.

Plan Category	Number of Securities To Be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by unitholders	N/A	N/A	N/A
Equity compensation plans not approved by unitholders	0	N/A	861

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

Transactions with Related Persons

Management and Administrative Services

We are managed and controlled by our general partner pursuant to our partnership agreement. Under our partnership agreement, our general partner is reimbursed for all direct and indirect expenses it incurs or payments it makes on our behalf. These expenses include salaries, fees and other compensation and benefit expenses of employees, officers and directors, insurance, other administrative or overhead expenses and all other expenses necessary or appropriate to conduct our business. The costs allocated to us by our general partner for administrative services and overhead totaled $5.1 million, $4.2 million and $4.5 million for the years ended December 31, 2008, 2007 and 2006.

Incentive Distributions

Our partnership agreement provides for incentive distributions payable to our general partner out of our Available Cash (as defined in our partnership agreement) in the event quarterly distributions to unitholders exceed certain specified targets. In general, subject to certain limitations, if a quarterly distribution exceeds a target of $0.275 per common unit, our general partner will receive incentive distributions equal to (i) 15% of that portion of the distribution per common unit which exceeds but is not more than $0.325, plus (ii) 25% of that portion of the quarterly distribution per common unit which exceeds $0.325 but is not more than $0.375, plus (iii) 50% of that portion of the quarterly distribution per common unit which exceeds $0.375. In 2008, our general partner received total distributions, including incentive distributions, of $57.5 million from us. See also Item 1, "Business—Partnership Distributions."

Units Purchase Agreement

In connection with our acquisition of Lone Star, we entered into a Units Purchase Agreement with Penn Virginia Resource LP Corp., or LP Corp, and Kanawha Rail Corp., or KRC, each a wholly owned subsidiary of Penn Virginia. Pursuant to the Units Purchase Agreement, we purchased an aggregate of 2,009,995 common units of PVG from LP Corp and KRC for an aggregate purchase price of $61.8 million. We delivered such PVG common units to Lone Star in payment of a portion of the purchase price of the Lone Star acquisition.

Oil and Gas Marketing Agreement

Connect Energy, our wholly owned subsidiary, and PVOG LP, Penn Virginia's wholly owned subsidiary, are parties to a Master Services Agreement effective September 1, 2006. Pursuant to the Master Services Agreement, Connect Energy and PVOG LP have agreed that Connect Energy will market all of PVOG LP's oil and gas production in Arkansas, Louisiana, Oklahoma and Texas for a fee equal to 1% of the net sales price (subject to specified limitations) received by PVOG LP for such production. The Master Services Agreement has a primary term of five years and automatically renews for additional one year terms until terminated by either party. In 2008, PVOG LP paid Connect Energy $3.0 million in fees pursuant to the Master Services Agreement.

Gas Gathering and Processing Agreement

PVR East Texas Gas Processing LLC, or PVR East Texas, our wholly owned subsidiary, and PVOG LP are parties to a Gas Gathering and Processing Agreement effective April 1, 2007. Pursuant to the Gas Gathering and Processing Agreement, PVR East Texas and PVOG LP have agreed that PVR East Texas will gather and process all of PVOG LP's current and future gas production in certain areas of the Bethany Field in East Texas and redeliver the NGLs to PVOG LP for a $0.30/MMBtu service fee (with an annual CPI adjustment). The Gas Gathering and Processing Agreement has a primary term of 15 years and automatically renews for additional one year terms until terminated by either party. PVR East Texas began gathering and processing PVOG LP's gas upon completion of the new Crossroads System in June 2008. In 2008, PVOG LP paid PVR East Texas $2.0 million in fees pursuant to the Gas Gathering and Processing Agreement.

Gas Purchase Arrangement

From time to time, Connect Energy purchases gas or NGLs from PVOG LP at our Crossroads Plant and resells such gas or NGLs to third parties. The purchase price paid by Connect Energy to PVOG LP for such gas or NGLs equals the sales price received by Connect Energy for such gas or NGLs from the third parties. In 2008, Connect Energy paid PVOG LP $127.9 million in connection with such purchases.

Omnibus Agreement

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

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

Non-Compete Agreement

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

Policies and Procedures Regarding Transactions with Related Persons

Under our Corporate Governance Principles, all directors must recuse themselves from any decision affecting their personal, business or professional interests. In addition, as a general matter, our practice is that any proposed transaction between us (or any of our subsidiaries) and Penn Virginia or PVG (or any of their respective subsidiaries) is approved by the conflicts committee of our general partner. For a discussion of the conflicts committee of our general partner, see Item 10, "Directors, Executive Officers and Corporate Governance—Committees of the Board of Directors of our General Partner—Conflicts Committee." With respect to any proposed transaction with any other related person, as a general matter, our practice is that such transactions are approved by disinterested directors. The General Counsel of our general partner advises the board of directors of our general partner as to which transactions involve related persons, which transactions require the approval of the conflicts committee of our general partner and which directors are prohibited from voting on a particular transaction. All of the related transactions described above which were entered into since January 1, 2008 were approved in accordance with the foregoing policies and procedures.

Director Independence

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

Item 14 *Principal Accounting Fees and Services*

In connection with the audits of our consolidated financial statements and our internal control over financial reporting, or ICFR, for 2008, we entered into an agreement with KPMG which sets forth the terms by which KPMG will perform audit services for us. That agreement is subject to alternative dispute resolution procedures, an exclusion of the right to collect punitive damages and various other provisions. The following table shows fees for professional audit services rendered by KPMG for the audits of our consolidated financial statements for 2008 and 2007 and the audits of our ICFR for 2008 and 2007 and fees billed for other services rendered by KPMG:

	2008	2007
Audit Fees (1)	$1,020,000	$766,800
Audit-Related Fees (2)	5,000	5,000
Tax Fees (3)	—	13,600
All Other Fees	—	—
Total Fees	$1,025,000	$785,400

(1) Audit fees consist of fees for the audit of our consolidated financial statements, the audit of our ICFR, consents for registration statements and comfort letters related to public offerings. Also included in audit fees are reimbursements of travel-related expenses.
(2) Audit-related fees consist of fees pertaining to debt compliance letters issued by KPMG for the Notes.
(3) Tax fees consist of fees for reviews of state tax returns for certain of our subsidiaries.

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

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

Part IV

Item 15 *Exhibits 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 69 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).

(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).

(3.3) 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).

(3.4) 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).

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

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

(10.1) Amended and Restated Credit Agreement, dated August 5, 2008, 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 Quarterly Report on Form 10-Q for the quarter ended September 30, 2008).

(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.*

(12.1) Statement of Computation of Ratio of Earnings to Fixed Charges Calculation.

(21.1) Subsidiaries of Penn Virginia Resource Partners, L.P.

(23.1) Consent of KPMG LLP.

(31.1) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(31.2) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(32.1) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(32.2) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENN VIRGINIA RESOURCE PARTNERS, L.P.

By: PENN VIRGINIA RESOURCE GP, LLC

February 27, 2009

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

February 27, 2009

By: /s/ FORREST W. MCNAIR
Forrest W. McNair
Vice President and Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ A. JAMES DEARLOVE **A. James Dearlove**	Chairman of the Board and Chief Executive Officer	February 27, 2009
/s/ EDWARD B. CLOUES, II **Edward B. Cloues, II**	Director	February 27, 2009
/s/ JAMES L. GARDNER **James L. Gardner**	Director	February 27, 2009
/s/ JAMES R. MONTAGUE **James R. Montague**	Director	February 27, 2009
/s/ MARSHA R. PERELMAN **Marsha R. Perelman**	Director	February 27, 2009
/s/ FRANK A. PICI **Frank A. Pici**	Director and Vice President and Chief Financial Officer	February 27, 2009
/s/ NANCY M. SNYDER **Nancy M. Snyder**	Director and Vice President and General Counsel	February 27, 2009

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,				
	2004	**2005**	**2006**	**2007**	**2008**
Earnings					
Pre-tax income *	$ 34,876	$ 52,430	$ 74,910	$ 55,552	$ 103,603
Fixed charges	7,328	14,351	19,783	19,766	26,850
Total earnings	**$ 42,204**	**$ 66,781**	**$ 94,693**	**$ 75,318**	**$ 130,453**
Fixed Charges					
Interest expense	$ 7,267	$ 14,053	$ 19,151	$ 18,896	$ 25,346
Rental interest factor	61	298	632	870	1,504
Total fixed charges	**$ 7,328**	**$ 14,351**	**$ 19,783**	**$ 19,766**	**$ 26,850**
Ratio of earnings to fixed charges	**5.8x**	**4.7x**	**4.8x**	**3.8x**	**4.9x**

* 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 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

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) and on Form S-3 (Nos. 333-106195 and 333-106239) of Penn Virginia Resource Partners, L.P. (the Partnership) of our reports dated February 27, 2009, with respect to the consolidated balance sheets of the Partnership as of December 31, 2008 and 2007, 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, 2008, and the effectiveness of internal control over financial reporting as of December 31, 2008, which reports appear in the December 31, 2008 annual report on Form 10-K of the Partnership.

/s/ KPMG LLP

Houston, Texas
February 27, 2009

Exhibit 31.1

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

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

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

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

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

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

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

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

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

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

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

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

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

Date: February 27, 2009

/s/ A. JAMES DEARLOVE

A. James Dearlove
Chief Executive Officer

Exhibit 31.2

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

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

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

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

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

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

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

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

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

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

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

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

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

Date: February 27, 2009

/s/ FRANK A. PICI

Frank A. Pici
Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Penn Virginia Resource Partners, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, A. James Dearlove, Chief Executive Officer of Penn Virginia Resource GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: February 27, 2009

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

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

Exhibit 32.2

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

In connection with the Annual Report of Penn Virginia Resource Partners, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Pici, Vice President and Chief Financial Officer of Penn Virginia Resource GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: February 27, 2009

/s/ FRANK A. PICI

Frank A. Pici
Vice President and Chief Financial Officer

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

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PARTNERSHIP INFORMATION

DIRECTORS*

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

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

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

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

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

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

Nancy M. Snyder
Vice President, Chief Administrative Officer and General Counsel; Executive Vice President and Chief Administrative Officer, General Counsel and Corporate Secretary of Penn Virginia Corporation; Director, Vice President, Chief Administrative Officer and General Counsel of PVG GP, LLC

* Of our general partner, Penn Virginia Resource GP, LLC
(1) Member of the Audit Committee
(2) Member of the Compensation and Benefits Committee
(3) Member of the Conflicts Committee

MANAGEMENT*

A. James Dearlove
Chief Executive Officer

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

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

Frank A. Pici
Vice President and Chief Financial Officer

Nancy M. Snyder
Vice President, Chief Administrative Officer and General Counsel

Forrest W. McNair
Vice President and Controller

Steven A. Hartman
Vice President and Treasurer

James F. Modzelewski
Vice President and Assistant General Counsel

Patrick J. Udovich
Vice President, Human Resources

James W. Dean
Vice President, Investor Relations

Jean M. Whitehead
Secretary

TRANSFER AGENT AND REGISTRAR

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

CERTIFICATIONS

In 2008, PVR submitted our Section 303A.12(a) chief executive officer certification to the New York Stock Exchange. We have also filed with the Securities and Exchange Commission, as an exhibit to our most recently filed Annual Report on Form 10-K, the Sarbanes-Oxley Act Section 302 certifications.

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PENN VIRGINIA RESOURCE PARTNERS, L.P.

Three Radnor Corporate Center, Suite 300

100 Matsonford Road, Radnor, PA 19087

610.687.8900 phone | 610.687.3688 fax

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