ONE Gas, Inc.
Form 10-Q
August 01, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

X Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2017.
OR
___ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __________ to __________.

Commission file number 001-36108

ONE Gas, Inc.
(Exact name of registrant as specified in its charter)

Oklahoma	46-3561936
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15 East Fifth Street, Tulsa, OK	74103
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (918) 947-7000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes X No __

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer X Accelerated filer __

Non-accelerated filer __ (Do not check if a smaller reporting company)

Smaller reporting company__

Emerging growth company__

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.__

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

On July 25, 2017, the Company had 52,269,117 shares of common stock outstanding.

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ONE Gas, Inc.
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As used in this Quarterly Report, references to “we,” “our,” “us” or the “company” refer to ONE Gas, Inc., an Oklahoma corporation, and its predecessors and subsidiary, unless the context indicates otherwise.

The statements in this Quarterly Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “pl “believe,” “should,” “goal,” “forecast,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled” and other w of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations, “Forward-Looking Statements,” in this Quarterly Report and under Part I, Item IA, “Risk Factors,” in our Annual Report.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge, on our website (www.onegas.com) copies of our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and Director Independence Guidelines are also available on our website, and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

We also make available on our website the Interactive Data Files required to be submitted and posted pursuant to Rule 405 of Regulation S-T.

GLOSSARY

The abbreviations, acronyms and industry terminology used in this Quarterly Report are defined as follows:

Annual Report	Annual Report on Form 10-K for the year ended December 31, 2016
ASU	Accounting Standards Update
Bcf	Billion cubic feet
CERCLA	Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Clean Air Act	Federal Clean Air Act, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
COSA	Cost-of-Service Adjustment
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
EPS	Earnings per share
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
GAAP	Accounting principles generally accepted in the United States of America
GRIP	Texas Gas Reliability Infrastructure Program
GSRS	Kansas Gas System Reliability Surcharge
Heating Degree Day or HDD	A measure designed to reflect the demand for energy needed for heating based on the extent to which the daily average temperature falls below a reference temperature for which no heating is required, usually 65 degrees Fahrenheit
IRS	Internal Revenue Service
KCC	Kansas Corporation Commission
KDHE	Kansas Department of Health and Environment
LDC	Local distribution company
MMcf	Million cubic feet
Moody's	Moody's Investors Service, Inc.
NPRM	Notice of Proposed Rulemaking
NYMEX	New York Mercantile Exchange
OCC	Oklahoma Corporation Commission
ONE Gas	ONE Gas, Inc.
ONE Gas Credit Agreement	ONE Gas' $700 million revolving credit agreement, which expires January, 2019
ONEOK	ONEOK, Inc. and its subsidiaries
PBRC	Performance-Based Rate Change
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
Pipeline Safety, Regulatory Certainty and Job Creation Act	Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, as amended
Quarterly Report(s)	Quarterly Report(s) on Form 10-Q
RRC	Railroad Commission of Texas
S&P	Standard & Poor's Ratings Services
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Senior Notes	ONE Gas' registered notes consisting of $300 million of 2.07 percent senior notes due 2019, $300 million of 3.61 percent senior notes due 2024 and $600 million of 4.658 percent notes due 2044.

Separation and Distribution Agreement	Separation and Distribution Agreement dated January 14, 2014, between ONEOK and ONE Gas
WNA	Weather-normalization adjustments
XBRL	eXtensible Business Reporting Language

PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ONE Gas, Inc.
STATEMENTS OF INCOME

(Unaudited)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	(Thousands of dollars, except per share amounts)			
Revenues	$279,689	$245,923	$830,097	$754,288
Cost of natural gas	82,572	56,457	345,726	292,186
Net margin	197,117	189,466	484,371	462,102
Operating expenses				
Operations and maintenance	101,241	97,119	210,598	203,250
Depreciation and amortization	37,851	35,565	74,870	70,249
General taxes	13,973	13,161	29,719	28,908
Total operating expenses	153,065	145,845	315,187	302,407
Operating income	44,052	43,621	169,184	159,695
Other income	875	416	2,121	434
Other expense	(462)	(314)	(802)	(769)
Interest expense, net	(11,305)	(10,848)	(22,786)	(21,695)
Income before income taxes	33,160	32,875	147,717	137,665
Income taxes	(12,537)	(12,575)	(50,638)	(52,621)
Net income	$20,623	$20,300	$97,079	$85,044
Earnings per share				
Basic	$0.39	$0.39	$1.85	$1.62
Diluted	$0.39	$0.38	$1.83	$1.61
Average shares (thousands)				
Basic	52,553	52,386	52,565	52,452
Diluted	52,969	52,836	53,012	52,972
Dividends declared per share of stock	$0.42	$0.35	$0.84	$0.70

See accompanying Notes to the Financial Statements.

ONE Gas, Inc.
STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
	(Thousands of dollars)			
Net income	$20,623	$20,300	$97,079	$85,044
Other comprehensive income (loss), net of tax				
Change in pension and other postemployment benefit plan liability, net of tax of $(81), $(73), $(161) and $(145), respectively	129	115	258	231
Total other comprehensive income (loss), net of tax	129	115	258	231
Comprehensive income	$20,752	$20,415	$97,337	$85,275

See accompanying Notes to the Financial Statements.

ONE Gas, Inc.
BALANCE SHEETS

(Unaudited)	June 30, 2017	December 31, 2016
Assets	(Thousands of dollars)	
Property, plant and equipment		
Property, plant and equipment	$5,545,302	$5,404,168
Accumulated depreciation and amortization	1,710,509	1,672,548
Net property, plant and equipment	3,834,793	3,731,620
Current assets		
Cash and cash equivalents	5,113	14,663
Accounts receivable, net	152,278	290,944
Materials and supplies	36,876	34,084
Natural gas in storage	114,996	125,432
Regulatory assets	82,302	83,146
Other current assets	20,014	20,654
Total current assets	411,579	568,923
Goodwill and other assets		
Regulatory assets	421,094	440,522
Goodwill	157,953	157,953
Other assets	47,711	43,773
Total goodwill and other assets	626,758	642,248
Total assets	$4,873,130	$4,942,791

See accompanying Notes to the Financial Statements.

ONE Gas, Inc.
BALANCE SHEETS
(Continued)

(Unaudited)	June 30, 2017	December 31, 2016
Equity and Liabilities	(Thousands of dollars)	
Equity and long-term debt		
Common stock, $0.01 par value:		
authorized 250,000,000 shares; issued 52,598,005 shares and outstanding 52,267,296 shares at June 30, 2017; issued 52,598,005 and outstanding 52,283,260 shares at December 31, 2016	$526	$526
Paid-in capital	1,734,083	1,749,574
Retained earnings	224,570	161,021
Accumulated other comprehensive income (loss)	(4,457)	(4,715)
Treasury stock, at cost: 330,709 shares at June 30, 2017 and 314,745 shares at December 31, 2016	(21,426)	(18,126)
Total equity	1,933,296	1,888,280
Long-term debt, excluding current maturities, and net of issuance costs of $8,445 and $8,851, respectively	1,192,848	1,192,446
Total equity and long-term debt	3,126,144	3,080,726
Current liabilities		
Notes payable	79,000	145,000
Accounts payable	60,458	131,988
Accrued interest	18,958	18,854
Accrued taxes other than income	33,562	42,571
Accrued liabilities	16,202	22,931
Customer deposits	60,523	61,209
Other current liabilities	23,982	21,380
Total current liabilities	292,685	443,933
Deferred credits and other liabilities		
Deferred income taxes	1,077,992	1,038,568
Employee benefit obligations	296,881	303,507
Other deferred credits	79,428	76,057
Total deferred credits and other liabilities	1,454,301	1,418,132
Commitments and contingencies		
Total liabilities and equity	$4,873,130	$4,942,791

See accompanying Notes to the Financial Statements.

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ONE Gas, Inc.
STATEMENTS OF CASH FLOWS

(Unaudited)	Six Months Ended June 30, 2017	2016
	(Thousands of dollars)	
Operating activities		
Net income	$97,079	$85,044
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	74,870	70,249
Deferred income taxes	50,308	36,031
Share-based compensation expense	4,951	7,451
Provision for doubtful accounts	3,501	2,757
Changes in assets and liabilities:		
Accounts receivable	135,165	98,321
Materials and supplies	(2,792)	707
Natural gas in storage	10,436	38,412
Asset removal costs	(22,837)	(27,672)
Accounts payable	(68,992)	(42,897)
Accrued interest	104	53
Accrued taxes other than income	(9,009)	(5,573)
Accrued liabilities	(6,729)	(16,156)
Customer deposits	(686)	1,113
Regulatory assets and liabilities	19,782	(2,966)
Other assets and liabilities	(5,880)	31,341
Cash provided by operating activities	279,271	276,215
Investing activities		
Capital expenditures	(154,666)	(144,760)
Other	477	492
Cash used in investing activities	(154,189)	(144,268)
Financing activities		
Repayments of notes payable, net	(66,000)	(12,500)
Repurchase of common stock	(17,512)	(24,066)
Issuance of common stock	2,208	1,983
Dividends paid	(44,042)	(36,638)
Tax withholdings related to net share settlements of stock compensation	(9,286)	(8,902)
Cash used in financing activities	(134,632)	(80,123)
Change in cash and cash equivalents	(9,550)	51,824
Cash and cash equivalents at beginning of period	14,663	2,433
Cash and cash equivalents at end of period	$5,113	$54,257

See accompanying Notes to the Financial Statements.

ONE Gas, Inc.
STATEMENT OF EQUITY

(Unaudited)	Common Stock Issued	Common Stock	Paid-in Capital
	(Shares)	(Thousands of dollars)	
January 1, 2017	52,598,005	$526	$1,749,574
Cumulative effect of accounting change	—	—	—
Net income	—	—	—
Other comprehensive income	—	—	—
Repurchase of common stock	—	—	—
Common stock issued and other	—	—	(15,961)
Common stock dividends - $0.84 per share	—	—	470
June 30, 2017	52,598,005	$526	$1,734,083

See accompanying Notes to the Financial Statements.

ONE Gas, Inc.
STATEMENT OF EQUITY
(Continued)

(Unaudited)	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Equity
	(Thousands of dollars)			
January 1, 2017	$161,021	$(18,126)	$ (4,715)	$1,888,280
Cumulative effect of accounting change	10,982	—	—	10,982
Net income	97,079	—	—	97,079
Other comprehensive income	—	—	258	258
Repurchase of common stock	—	(17,512)	—	(17,512)
Common stock issued and other	—	14,212	—	(1,749)
Common stock dividends - $0.84 per share	(44,512)	—	—	(44,042)
June 30, 2017	$224,570	$(21,426)	$ (4,457)	$1,933,296

See accompanying Notes to the Financial Statements.

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ONE Gas, Inc.
NOTES TO THE FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our accompanying unaudited financial statements have been prepared pursuant to the rules and regulations of the SEC. These statements also have been prepared in accordance with GAAP and reflect all adjustments that, in our opinion, are necessary for a fair statement of the results for the interim periods presented. All such adjustments are of a normal recurring nature. The 2016 year-end balance sheet data was derived from audited financial statements, but does not include all disclosures required by GAAP. These unaudited financial statements should be read in conjunction with the audited financial statements and footnotes in our Annual Report. Due to the seasonal nature of our business, the results of operations for the three and six months ended June 30, 2017, are not necessarily indicative of the results that may be expected for a 12-month period.

We provide natural gas distribution services to more than 2 million customers through our divisions in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. We serve residential, commercial, industrial and transportation customers in all three states. In addition, we also provide natural gas distribution services to wholesale and public authority customers.

Use of Estimates - The preparation of our financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, provision for doubtful accounts, unbilled revenues for natural gas delivered but for which meters have not been read, natural gas purchased but for which no invoice has been received, provision for income taxes, including any deferred tax valuation allowances, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Segments - We operate in one reportable and operating business segment: regulated public utilities that deliver natural gas to residential, commercial, industrial, wholesale, public authority and transportation customers. The accounting policies for our segment are the same as described in Note 1 of our Notes to the Financial Statements in our Annual Report. We evaluate our financial performance principally on operating income. For the three and six months ended June 30, 2017, and 2016, we had no single external customer from which we received 10 percent or more of our gross revenues.

Recently Issued Accounting Standards Update - In March 2017, the FASB issued ASU 2017-07, “Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,” which requires (1) separation of net periodic service costs for pension and other postemployment benefits into service cost and other components, (2) presentation of the service cost component in the same line as other compensation costs rendered by pertinent employees during the period, and (3) reporting the other components of net periodic benefit costs separately from the service cost component and outside a subtotal of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all of our cost components remain eligible for capitalization under the accounting requirements for rate regulated entities.

We are required to adopt this guidance for our interim and annual reports for periods beginning after December 15, 2017. When adopted, the presentation changes required for net periodic benefit costs will not impact previously reported net income; however, the reclassification of the other components of benefits costs will result in an increase in operating income and an increase in other expenses for 2016 and 2017. We continue to evaluate the impact of this guidance including the impact on our capitalization policies considering our regulated operations.

In January 2017, the FASB issued ASU 2017-04, “Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment,” which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 of the goodwill test, where the measurement of a goodwill impairment loss was determined by comparing the implied fair value of a reporting unit’s goodwill with the carrying amount of that goodwill. Upon adoption, a goodwill impairment will be the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. This new guidance is required for our interim and annual reports for periods beginning after December 15, 2019, and early adoption is permitted. We do not expect this guidance to have a material impact on our financial statements and will adjust our goodwill testing procedures accordingly upon adoption.

In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting," which includes various new aspects to simplify how share-based payments are accounted for and presented in the financial statements. The new standard modifies several aspects of the accounting and reporting for employee share-based payments and related tax accounting impacts, including the presentation in the statements of operations and cash flows. We adopted this new guidance in the first quarter 2017, and in accordance with the transition requirements, we recorded $5.2 million of excess tax benefit in income tax expense and have transitioned all provisions of this new guidance prospectively, other than our presentation of our withholding shares for tax-withholding purposes, which we accounted for retrospectively in the financing activities section of the statement of cash flows. We recorded a noncash cumulative-effect increase of $11.0 million to retained earnings, with an offset to a deferred tax asset, as of the beginning of the reporting period in 2017, for excess tax benefits earned prior to January 1, 2017, that had not been recognized. We continue our use of the estimation method to account for share unit awards forfeitures rather than actual forfeitures. The retrospective impact of our withholding shares for tax-withholding purposes to our Statement of Cash Flows for the six months ended June 30, 2016, was a $8.9 million increase to net cash provided by operating activities and a $8.9 million decrease to net cash used in financing activities.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)," which prescribes recognizing lease assets and liabilities on the balance sheet and includes disclosure of key information about leasing arrangements. A modified retrospective transition approach is required for leases existing at the time of adoption. We are evaluating our population of leases, analyzing lease agreements, and holding meetings with cross-functional teams to determine the potential impact of this accounting standard on our financial position and results of operations and the transition approach we will utilize. This new guidance is required for our interim and annual reports for periods beginning after December 15, 2018, and early adoption is permitted.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers," which clarifies and converges the revenue recognition principles under GAAP and International Financial Reporting Standards. In July 2015, FASB delayed the effective date for one year. We have substantially completed evaluating all of our sources of revenue to determine the potential effect on our financial position, results of operations, cash flows and the related accounting policies and business processes. We are evaluating this information to determine what information will be disclosed in our financial statements and footnotes. In addition to updating our revenue recognition disclosures, additional disclosures may include disaggregation of revenues by types of service, source of revenue or customer class, performance obligations and other types of revenues.

We continue to monitor accounting task forces and the FASB for additional implementation guidance related to: (1) the accounting for funds received from third parties to partially or fully reimburse the cost of construction of an asset; (2) the evaluation of collectability from customers if a utility has regulatory mechanisms to help assure recovery of uncollected accounts from ratepayers; and (3) the accounting for alternative revenue programs, such as weather normalization, that may impact the final conclusions of our evaluation. Until these items are resolved, we cannot complete our evaluation of the potential effect the new guidance will have on our financial position, results of operations, cash flows or business processes.

We will adopt this new guidance for our interim and annual reports beginning with the first quarter 2018.

2. REGULATORY ASSETS AND LIABILITIES

The tables below present a summary of regulatory assets, net of amortization, and liabilities for the periods indicated:

	June 30, 2017		
	Current	Noncurrent	Total
	(Thousands of dollars)		
Under-recovered purchased-gas costs	$26,500	$—	$26,500
Pension and postemployment benefit costs	31,498	408,593	440,091
Weather normalization	20,311	—	20,311
Reacquired debt costs	812	7,703	8,515
Other	3,181	4,798	7,979
Total regulatory assets, net of amortization	82,302	421,094	503,396
Over-recovered purchased-gas costs	(14,049)	—	(14,049)
Ad valorem tax	(606)	—	(606)
Total regulatory liabilities (a)	(14,655)	—	(14,655)
Net regulatory assets (liabilities)	$67,647	$ 421,094	$488,741

(a) Included in other current liabilities in our Balance Sheets.

	December 31, 2016		
	Current	Noncurrent	Total
	(Thousands of dollars)		
Under-recovered purchased-gas costs	$29,901	$—	$29,901
Pension and postemployment benefit costs	31,498	427,448	458,946
Weather normalization	17,661	—	17,661
Reacquired debt costs	812	8,108	8,920
Other	3,274	4,966	8,240
Total regulatory assets, net of amortization	83,146	440,522	523,668
Over-recovered purchased-gas costs	(10,154)	—	(10,154)
Ad valorem tax	(1,768)	—	(1,768)
Total regulatory liabilities (a)	(11,922)	—	(11,922)
Net regulatory assets (liabilities)	$71,224	$ 440,522	$511,746

(a) Included in other current liabilities in our Balance Sheets.

Regulatory assets on our Balance Sheets, as authorized by various regulatory authorities, are probable of recovery. Base rates are designed to provide a recovery of costs during the period rates are in effect, but do not generally provide for a return on investment for amounts we have deferred as regulatory assets. All of our regulatory assets are subject to review by the respective regulatory authorities during future regulatory proceedings. We are not aware of any evidence that these costs will not be recoverable through either riders or base rates, and we believe that we will be able to recover such costs, consistent with our historical recoveries.

3. CREDIT FACILITY AND SHORT-TERM NOTES PAYABLE

The ONE Gas Credit Agreement contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas' debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. At June 30, 2017, our debt-to-capital ratio was 40 percent and we were in compliance with all covenants under the ONE Gas Credit Agreement.

We have a commercial paper program under which we may issue unsecured commercial paper up to a maximum amount of $700 million to fund short-term borrowing needs. The maturities of the commercial paper notes may vary but may not exceed 270 days from the date of issue. The commercial paper notes are generally sold at par less a discount representing an interest factor.

The ONE Gas Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONE Gas Credit Agreement. At June 30, 2017, we had

$79.0 million in short-term borrowings, $1.8 million in letters of credit issued under the ONE Gas Credit Agreement and $619.2 million of remaining credit available under the ONE Gas Credit Agreement.

4. LONG-TERM DEBT

We have senior notes consisting of $300 million of 2.07 percent senior notes due in 2019, $300 million of 3.61 percent senior notes due in 2024 and $600 million of 4.658 percent senior notes due in 2044. The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding Senior Notes to declare those Senior Notes immediately due and payable in full.

5. EQUITY

Treasury Shares - For the six months ended June 30, 2017, we repurchased approximately 256 thousand shares of our common stock for approximately $17.5 million.

Dividends Declared - In July 2017, we declared a dividend of $0.42 per share ($1.68 per share on an annualized basis) for shareholders of record as of August 14, 2017, payable September 1, 2017.

6. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following table sets forth the effect of reclassifications from accumulated other comprehensive income (loss) in our Statements of Income for the periods indicated:

	Three Months Ended		Six Months Ended		
Details about Accumulated Other Comprehensive	June 30,		June 30,		Affected Line Item in the
Income (Loss) Components	2017	2016	2017	2016	Statements of Income
	(Thousands of dollars)				
Pension and other postemployment benefit plan obligations (a)					
Amortization of net loss	$10,648	$10,036	$21,296	$20,073	
Amortization of unrecognized prior service cost	(1,149)	(908)	(2,298)	(1,816)	
	9,499	9,128	18,998	18,257	
Regulatory adjustments (b)	(9,289)	(8,940)	(18,579)	(17,881)	
	210	188	419	376	Income before income taxes
	(81)	(73)	(161)	(145)	Income tax expense
Total reclassifications for the period	$129	$115	$258	$231	Net income

(a) These components of accumulated other comprehensive income (loss) are included in the computation of net periodic benefit cost. See Note 8 for additional detail of our net periodic benefit cost.
(b) Regulatory adjustments represent pension and other postemployment benefit costs expected to be recovered through rates and are deferred as part of our regulatory assets. See Note 2 for additional disclosures of regulatory assets and liabilities.

7. EARNINGS PER SHARE

Basic EPS is based on net income and is calculated based upon the daily weighted-average number of common shares outstanding during the periods presented. Also, this calculation includes fully vested stock awards that have not yet been issued as common stock. Diluted EPS includes basic EPS, plus unvested stock awards granted under our compensation plans, but only to the extent these instruments dilute earnings per share.

The following tables set forth the computation of basic and diluted EPS from continuing operations for the periods indicated:

	Three Months Ended June 30, 2017		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$20,623	52,553	$ 0.39
Diluted EPS Calculation			
Effect of dilutive securities	—	416	
Net income available for common stock and common stock equivalents	$20,623	52,969	$ 0.39

	Three Months Ended June 30, 2016		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$20,300	52,386	$ 0.39
Diluted EPS Calculation			
Effect of dilutive securities	—	450	
Net income available for common stock and common stock equivalents	$20,300	52,836	$ 0.38

	Six Months Ended June 30, 2017		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$97,079	52,565	$ 1.85
Diluted EPS Calculation			
Effect of dilutive securities	—	447	
Net income available for common stock and common stock equivalents	$97,079	53,012	$ 1.83

	Six Months Ended June 30, 2016		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$85,044	52,452	$ 1.62

Diluted EPS Calculation			
Effect of dilutive securities	—	520	
Net income available for common stock and common stock equivalents	$85,044	52,972	$ 1.61

8. EMPLOYEE BENEFIT PLANS

The following tables set forth the components of net periodic benefit cost for our pension and other postemployment benefit plans for the periods indicated:

	Pension Benefits			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
	(Thousands of dollars)			
Components of net periodic benefit cost				
Service cost	$3,044	$3,014	$6,088	$6,028
Interest cost	10,113	11,388	20,226	22,775
Expected return on assets	(14,624)	(15,296)	(29,248)	(30,592)
Amortization of net loss	9,027	8,885	18,054	17,771
Net periodic benefit cost	$7,560	$7,991	$15,120	$15,982

	Other Postemployment Benefits			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
	(Thousands of dollars)			
Components of net periodic benefit cost				
Service cost	$627	$638	$1,254	$1,276
Interest cost	2,472	2,627	4,944	5,254
Expected return on assets	(3,147)	(3,071)	(6,294)	(6,142)
Amortization of unrecognized prior service cost	(1,149)	(908)	(2,298)	(1,816)
Amortization of net loss	1,621	1,151	3,242	2,302
Net periodic benefit cost	$424	$437	$848	$874

We recover qualified pension benefit plan and other postemployment benefit plan costs through rates charged to our customers. Certain utility commissions require that the recovery of these costs be based on specific guidelines. The difference between these regulatory-based amounts and the periodic benefit cost calculated pursuant to GAAP is deferred as a regulatory asset or liability and amortized to expense over periods in which this difference will be recovered in rates, as authorized by the applicable utility commission. Regulatory deferrals related to net periodic benefit cost were not material for the three and six months ended June 30, 2017.

9. COMMITMENTS AND CONTINGENCIES

Environmental Matters - We are subject to multiple historical, wildlife preservation and environmental laws and/or regulations, which affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetland preservation, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. In addition, emission controls and/or other regulatory or permitting mandates under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental investigation, and remediation compliance to-date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during the three and six months ended June 30, 2017 and 2016.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured gas sites in Kansas. These sites contain contaminants generally associated with manufactured gas sites and are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE governs all work at these sites. The terms of the consent agreement require us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation typically involves the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater.

We have completed or addressed removal of the source of soil contamination at 11 of the 12 sites, and continue to monitor groundwater at eight of the 12 sites according to plans approved by the KDHE. Regulatory closure has been achieved at three of the 12 sites, but these sites remain subject to potential future requirements that may result in additional costs. During 2016, we completed a site assessment at the twelfth site where no active soil remediation has occurred. We have submitted a work plan to the KDHE for approval to address a source of contamination and associated contaminated soil on a portion of this site. We are also conducting a study of the feasibility of various options to address the remainder of the site. Costs associated with the remediation at this site are not expected to be material to our results of operations or financial position.

With regard to one of our former manufactured gas sites, periodic monitoring and a 2016 interim site investigation indicated elevated levels of contaminants generally associated with manufactured gas sites. Additional testing and work plan development is underway in 2017 to determine a remediation work plan to present to the KDHE for approval, which could impact our estimates of the cost of remediation at this site. In the fourth quarter of 2016, we estimated the potential costs associated with additional investigation and remediation to be in the range of $4.0 million to $7.0 million. A single reliable estimate of the remediation costs is not feasible due to the amount of uncertainty in the ultimate remediation approach that will be utilized. Accordingly, we recorded a reserve of $4.0 million for this site in the fourth quarter of 2016.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during the three and six months ended June 30, 2017 and 2016. A number of environmental issues may exist with respect to manufactured gas sites that are unknown to us. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation required, changing technology and governmental regulations, and to the extent not recovered by insurance or recoverable in rates from our customers, could be material to our financial condition, results of operations or cash flows.

With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us that are subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully recovered by insurance or recoverable in rates from our customers, and those costs may adversely affect our financial condition, results of operations and cash flows. We do not expect expenditures for these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including integrity-management regulations. PHMSA regulations require pipeline companies operating high-pressure transmission pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act was signed into law. The law increased maximum penalties for violating federal pipeline safety regulations and directs the DOT and the Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include, but are not limited to, the following:

- an evaluation of whether natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;

- a verification of records for pipelines in class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and
- a requirement to test previously untested pipelines operating above 30 percent yield strength in high-consequence areas.

In April 2016, PHMSA published a NPRM, the Safety of Gas Transmission & Gathering Lines Rule, in the Federal Register to revise pipeline safety regulations applicable to the safety of onshore natural gas transmission and gathering pipelines. Proposals include changes to pipeline integrity management requirements and other safety-related requirements. The NPRM comment period ended July 7, 2016, and comments are under review by PHMSA. As part of the comment review process, PHMSA is being advised by the Technical Pipeline Safety Standards Committee, informally known by PHMSA as the Gas Pipeline Advisory Committee ("GPAC"), a statutorily mandated advisory committee that advises PHMSA on proposed safety policies for natural gas pipelines. The GPAC reviews PHMSA's proposed regulatory initiatives to assure the technical feasibility, reasonableness, cost-effectiveness and practicality of each proposal. The potential capital and operating expenditures associated with compliance with the proposed rule are currently being evaluated and could be significant depending on the final regulations.

Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows.

10. DERIVATIVE FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENTS

Accounting Treatment - We record all derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it, or if regulatory rulings require a different accounting treatment.

If certain conditions are met, we may elect to designate a derivative instrument as a hedge to mitigate the risk of exposure to changes in fair values or cash flows.

The table below summarizes the various ways in which we account for our derivative instruments and the impact on our financial statements:

		Recognition and Measurement		
Accounting Treatment		Balance Sheet		Income Statement
Normal purchases and normal sales	-	Recorded at historical cost	-	Change in fair value not recognized in earnings
Mark-to-market	-	Recorded at fair value	-	Change in fair value recognized in, and recoverable through, the purchased-gas cost adjustment mechanisms

We have not elected to designate any of our derivative instruments as hedges. Premiums paid and any cash settlements received associated with the commodity derivative instruments entered into by us are included in, and recoverable through, the purchased-gas cost adjustment mechanisms.

Determining Fair Value - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use the market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. We measure the fair value of a group of financial assets and liabilities consistent with how a market participant would price the net risk exposure at the measurement date.

Fair Value Hierarchy - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are, either directly or indirectly, observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data; and
- Level 3 - May include one or more unobservable inputs that are significant in establishing a fair value estimate. These unobservable inputs are developed based on the best information available and may include our own internal data.

We recognize transfers into and out of the levels as of the end of each reporting period.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management’s judgment regarding the degree to which market data is observable or corroborated by observable market data. We categorize derivatives for which fair value is determined using multiple inputs within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety.

Derivative Instruments - At June 30, 2017, we held purchased natural gas call options for the heating season ending March 31, 2018, with total notional amounts of 14.6 Bcf, for which we paid premiums of $5.6 million, and had a fair value of $4.0

million. At December 31, 2016, we held purchased natural gas call options for the heating season ended March 31, 2017, with total notional amounts of 14.3 Bcf, for which we paid premiums of $5.4 million, and had a fair value of $6.5 million. The premiums paid and any cash settlements received are recorded as part of our unrecovered purchased-gas costs in current regulatory assets as these contracts are included in, and recoverable through, the purchased-gas cost adjustment mechanisms. Additionally, changes in fair value associated with these contracts are deferred as part of our unrecovered purchased-gas costs in our Balance Sheets. Our natural gas call options are classified as Level 1 as fair value amounts are based on unadjusted quoted prices in active markets including NYMEX-settled prices. There were no transfers between levels for the three and six months ended June 30, 2017 and 2016.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable and accounts payable is equal to book value, due to the short-term nature of these items. Our cash and cash equivalents are comprised of bank and money market accounts, and are classified as Level 1.

Short-term notes payable and commercial paper are due upon demand and, therefore, the carrying amounts approximate fair value and are classified as Level 1. The book value of our long-term debt, including current maturities, was $1.2 billion at both June 30, 2017 and December 31, 2016. The estimated fair value of our long-term debt, including current maturities, was $1.3 billion and $1.2 billion at June 30, 2017 and December 31, 2016, respectively. The estimated fair value of our Senior Notes at June 30, 2017 and December 31, 2016, was determined using quoted market prices, and are classified as Level 2.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our unaudited financial statements and the Notes to the Financial Statements in this Quarterly Report, as well as our Annual Report. Due to the seasonal nature of our business, the results of operations for the three and six months ended June 30, 2017, are not necessarily indicative of the results that may be expected for a 12-month period.

RECENT DEVELOPMENTS

Dividend - In July 2017, we declared a dividend of $0.42 per share ($1.68 per share on an annualized basis) for shareholders of record as of August 14, 2017, payable September 1, 2017.

REGULATORY ACTIVITIES

Oklahoma - In March 2017, Oklahoma Natural Gas filed its first annual PBRC following the general rate case that was approved in January 2016. This filing was based on a calendar test year of 2016. The PBRC filing demonstrated that Oklahoma Natural Gas was earning within the allowed return on equity range of 9.0 to 10.0 percent. Therefore, Oklahoma Natural Gas did not seek a modification to base rates. The filing also requested an energy efficiency program true-up and utility incentive adjustment of approximately $1.9 million. A joint stipulation and settlement agreement was filed on June 13, 2017, containing an agreement of these requests as filed. This joint stipulation and settlement agreement was heard by the administrative law judge on June 14, 2017, and is awaiting OCC approval. As required, PBRC filings are made annually on March 15, until the next general rate case, which is currently required to be filed on or before June 30, 2021, based on a calendar test year of 2020.

Kansas - In April 2017, Kansas Gas Service submitted an application to the KCC regarding the costs incurred at its 12 manufactured gas sites. Consistent with prior KCC precedent, Kansas Gas Service requested approval to: (1) defer expenditures incurred after December 31, 2016, as a regulatory asset and to amortize and recover such costs from customers in a future base rate proceeding over a ten-year period; (2) retain insurance recoveries up to $9.5 million, the amount Kansas Gas Service has spent for the period November 1, 1997, through December 31, 2016, and to exclude such amounts from the determination of the revenue requirement in future base rate proceedings; and (3) share insurance recoveries (less legal and other costs prudently incurred in obtaining the insurance recoveries) in excess of $9.5 million between customers and shareholders. The KCC is expected to issue an order no later than early January 2018.

In May 2016, Kansas Gas Service filed a request with the KCC for an increase in base rates, reflecting system investments and operating costs necessary to maintain the safety and reliability of its natural gas distribution system. Kansas Gas Service's request represented a net base rate increase of $28.0 million. Kansas Gas Service was already recovering approximately $7.4 million from customers through the GSRS mechanism, resulting in a total base rate increase of $35.4 million. In October 2016, Kansas Gas Service reached a unanimous settlement agreement with all parties for a net increase in base rates of approximately $8.1 million. Including the GSRS of approximately $7.4 million, the total base rate increase is $15.5 million. The agreement was a "black-box settlement," meaning the parties agreed to a specific revenue number but no specific return on equity or determination with respect to other contested issues. Additionally, the agreement modified the weather normalization clause to accrue the variation in net margin resulting from the difference in actual weather relative to normal weather over 12 months, rather than five months. The KCC issued an order approving the unanimous settlement agreement in November 2016, with new rates effective January 1, 2017.

Texas - West Texas Service Area - In March 2017, Texas Gas Service made GRIP filings for all customers in the West Texas Service Area requesting an increase of $4.5 million. The RRC and the cities approved an increase of $4.3 million for the customers in the service area, and new rates became effective in July 2017.

In March 2016, Texas Gas Service filed a rate case requesting an increase in revenues of $12.8 million for its El Paso, Dell City and Permian service areas, as well as consolidation of these three areas. In September 2016, the RRC approved the consolidation and a base rate increase of $8.8 million, which was based on a 9.5 percent return on equity and a 60.1 percent common equity ratio. In October 2016, new rates went into effect for all customers, except for those in the incorporated cities of the former Permian service area. Texas Gas Service filed for these new rates for customers in the incorporated cities of the former Permian service area in October 2016, and the rates became effective in December 2016.

Rio Grande Valley Service Area - In June 2017, Texas Gas Service filed a rate case requesting an increase in revenues of $4.5 million for customers in its Rio Grande Valley Service Area. If approved, new rates are expected to be effective in the fourth quarter of 2017.

Central Texas Service Area - In March 2017, Texas Gas Service made GRIP filings for customers of the consolidated Central Texas Service Area requesting an increase of $4.9 million. The request was approved by the cities and the RRC, and new rates became effective in June 2017.

In June 2016, Texas Gas Service filed a rate case requesting an increase in revenues of $11.6 million for its Central Texas and South Texas service areas. The filing included a request to consolidate the South Texas service area with the Central Texas service area. Texas Gas Service filed this rate case directly with the incorporated cities of the Central Texas service area, which includes the city of Austin, and the RRC for the unincorporated areas. In October 2016, all parties to the filing reached a unanimous settlement agreement for an increase in revenues of $6.8 million for the new consolidated service area. New rates were effective in November 2016, for customers in the incorporated cities of the former Central Texas service area. RRC approval was received in November 2016 and new rates became effective for customers in the unincorporated areas of the new consolidated Central Texas Service Area the same month. Texas Gas Service received approval for the same rates in the incorporated areas of the former South Texas service area with new rates effective in January 2017.

Gulf Coast Service Area - In December 2015, Texas Gas Service filed a rate case requesting an increase in revenues of $3.1 million for its Galveston and South Jefferson County service areas and to consolidate these two service areas into a new Gulf Coast Service Area. Texas Gas Service filed this rate case directly with the incorporated cities and the RRC for the unincorporated areas. Texas Gas Service reached a unanimous settlement agreement with representatives of the incorporated cities and the staff of the RRC on behalf of the unincorporated areas for an increase in revenues of $2.3 million. Following RRC approval, new rates became effective in May 2016.

Other Texas service areas - In the normal course of business, Texas Gas Service has sought GRIP and COSA increases in various other Texas jurisdictions to address investments in rate base and changes in expenses. Annual rate increases associated with approved filings totaled $1.1 million for the six months ended June 30, 2017, and $2.0 million for the year ended 2016.

FINANCIAL RESULTS AND OPERATING INFORMATION

We operate in one reportable and operating business segment: regulated public utilities that deliver natural gas to residential, commercial, industrial, wholesale, public authority and transportation customers. The accounting policies for our segment are the same as described in Note 1 of our Notes to the Financial Statements in our Annual Report. We evaluate our financial performance principally on operating income.

Selected Financial Results - For the three months ended June 30, 2017, net income was $20.6 million, or $0.39 per diluted share, compared with $20.3 million, or $0.38 per diluted share in the same period last year. For the six months ended June 30, 2017, net income was $97.1 million, or $1.83 per diluted share, compared with $85.0 million, or $1.61 per diluted share in the same period last year. Our prospective adoption of ASU 2016-09, “Improvements to Employee Share-Based Payment Accounting,” resulted in favorable impacts to income tax expense and our net income from recording $5.2 million of excess tax benefits as a reduction to income tax expense in the first quarter 2017. The following table sets forth certain selected financial results for our operations for the periods indicated:

	Three Months Ended		Six Months Ended		Three Months	Six Months
	June 30,		June 30,		2017 vs. 2016	2017 vs. 2016
Financial Results	2017	2016	2017	2016		

					Increase (Decrease)		Increase (Decrease)	
	(Millions of dollars, except percentages)							
Natural gas sales	$250.9	$217.2	$763.2	$688.6	$33.7	16 %	$74.6	11%
Transportation revenues	21.4	21.2	51.6	51.0	0.2	1 %	0.6	1 %
Cost of natural gas	82.5	56.5	345.7	292.2	26.0	46 %	53.5	18%
Net margin, excluding other revenues	189.8	181.9	469.1	447.4	7.9	4 %	21.7	5 %
Other revenues	7.4	7.6	15.3	14.7	(0.2)	(3)%	0.6	4 %
Net margin	197.2	189.5	484.4	462.1	7.7	4 %	22.3	5 %
Operating costs	115.2	110.4	240.3	232.2	4.8	4 %	8.1	3 %
Depreciation and amortization	37.9	35.5	74.9	70.2	2.4	7 %	4.7	7 %
Operating income	$44.1	$43.6	$169.2	$159.7	$0.5	1 %	$9.5	6 %
Capital expenditures	$84.2	$69.5	$154.7	$144.8	$14.7	21 %	$9.9	7 %

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Net margin is comprised of total revenues less cost of natural gas. Cost of natural gas includes commodity purchases, fuel, storage, transportation, the cost of gas component of bad debts and other gas purchase costs recovered through our cost of natural gas regulatory mechanisms during the periods presented and does not include an allocation of general operating costs or depreciation and amortization. Our cost of natural gas regulatory mechanisms provide a method of recovering natural gas costs on an ongoing basis without a profit. Therefore, although our revenues will fluctuate with the cost of gas that we recover, net margin is not affected by fluctuations in the cost of natural gas.

The following table sets forth our net margin, excluding other revenues, by type of customer, for the periods indicated:

Net Margin, Excluding Other Revenues	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016	Three Months 2017 vs. 2016 Increase (Decrease)		Six Months 2017 vs. 2016 Increase (Decrease)	
Natural gas sales	(Millions of dollars, except percentages)							
Residential	$139.7	$132.8	$347.9	$327.5	$ 6.9	5 %	$20.4	6 %
Commercial and industrial	27.5	26.7	66.4	65.5	0.8	3 %	0.9	1 %
Wholesale and public authority	1.2	1.2	3.2	3.4	—	—%	(0.2)	(6)%
Net margin on natural gas sales	168.4	160.7	417.5	396.4	7.7	5 %	21.1	5 %
Transportation revenues	21.4	21.2	51.6	51.0	0.2	1 %	0.6	1 %
Net margin, excluding other revenues	$189.8	$181.9	$469.1	$447.4	$ 7.9	4 %	$21.7	5 %

Our net margin on natural gas sales is comprised of two components, fixed and variable margin. Fixed margin reflects the portion of our net margin attributable to the monthly fixed customer charge component of our rates, which does not fluctuate based on customer usage in each period. Variable margin reflects the portion of our net margin that fluctuates with the volumes delivered and billed. We believe that the combination of the significant residential component of our customer base, the fixed charge component of our sales margin and our regulatory rate mechanisms that we have in place result in a stable cash flow profile. The following table sets forth our net margin on natural gas sales by revenue type for the periods indicated:

Net Margin on Natural Gas Sales	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016	Three Months 2017 vs. 2016 Increase (Decrease)		Six Months 2017 vs. 2016 Increase (Decrease)	
Net margin on natural gas sales	(Millions of dollars, except percentages)							
Fixed margin	$141.5	$139.9	$280.7	$281.8	$1.6	1 %	$(1.1)	— %
Variable margin	26.9	20.8	136.8	114.6	6.1	29 %	22.2	19 %
Net margin on natural gas sales	$168.4	$160.7	$417.5	$396.4	$7.7	5 %	$21.1	5 %

Net margin increased $7.7 million for the three months ended June 30, 2017, compared with the same period last year, due primarily to the following:

- an increase of $4.7 million from new rates in Texas and Kansas;
- an increase of $1.6 million from the impact of the modified weather-normalization mechanism in Kansas; and
- an increase of $0.8 million in residential sales due primarily to net customer growth in Oklahoma and Texas.

Net margin increased $22.3 million for the six months ended June 30, 2017, compared with the same period last year, due primarily to the following:

- an increase of $14.3 million from new rates in Texas and Kansas;
- an increase of $4.6 million from the impact of weather-normalization mechanisms, which offset warmer weather in 2017 compared with the same period in 2016;
- an increase of $1.7 million in residential sales due primarily to net customer growth in Oklahoma and Texas; and
- an increase of $1.0 million due primarily to higher transportation volumes from customers in Kansas and Oklahoma.

Operating costs increased $4.8 million for the three months ended June 30, 2017, compared with the same period last year, due primarily to the following:

- an increase of $2.4 million in employee-related costs;
- an increase of $0.9 million in information technology costs; and
- an increase of $0.9 million in costs associated with pipeline maintenance activities.

Operating costs increased $8.1 million for the six months ended June 30, 2017, compared with the same period last year, due primarily to the following:

- an increase of $2.4 million from the deferral in the first quarter of 2016 of certain information technology costs incurred as a result of our separation from ONEOK in 2014, which was approved in Oklahoma as a regulatory asset;
- an increase of $2.4 million in costs associated with pipeline maintenance activities;
- an increase of $1.9 million in information technology costs;
- an increase of $0.9 million in employee-related costs; and
- an increase of $0.7 million in bad debt expense; offset partially by
- a decrease of $1.8 million in legal-related costs.

Depreciation and amortization expense increased $2.4 million and $4.7 million for the three and six months ended June 30, 2017, respectively, compared with the same periods last year, due primarily to an increase in depreciation from our capital expenditures being placed in service, offset by decreases of $0.5 million and $1.0 million, respectively, in amortization expense associated primarily with other postemployment benefit deferrals in Kansas.

Capital Expenditures - Our capital expenditures program includes expenditures for pipeline integrity, extending service to new areas, modifications to customer service lines, increasing system capabilities, pipeline replacements, fleet, facilities and information technology assets. It is our practice to maintain and upgrade our infrastructure, facilities and systems to ensure safe, reliable and efficient operations.

Capital expenditures increased $14.7 million and $9.9 million for the three and six months ended June 30, 2017, respectively, compared with the same periods last year, due primarily to increased system integrity activities and extending service to new areas.

Selected Operating Information - The following tables set forth certain selected operating information for the periods indicated:

	Three Months Ended June 30,								Variances 2017 vs. 2016			
(in thousands)	2017				2016				Increase (Decrease)			
Average Number of Customers	OK	KS	TX	Total	OK	KS	TX	Total	OK	KS	TX	Total
Residential	794	584	619	1,997	789	583	612	1,984	5	1	7	13
Commercial and industrial	73	50	35	158	73	50	35	158	—	—	—	—
Wholesale and public authority	—	—	3	3	—	—	3	3	—	—	—	—
Transportation	5	6	1	12	5	6	1	12	—	—	—	—
Total customers	872	640	658	2,170	867	639	651	2,157	5	1	7	13

	Six Months Ended June 30,								Variances 2017 vs. 2016			
(in thousands)	2017				2016				Increase (Decrease)			
Average Number of Customers	OK	KS	TX	Total	OK	KS	TX	Total	OK	KS	TX	Total
Residential	796	587	618	2,001	791	584	612	1,987	5	3	6	14
Commercial and industrial	74	50	35	159	74	50	35	159	—	—	—	—
Wholesale and public authority	—	—	3	3	—	—	3	3	—	—	—	—
Transportation	5	6	1	12	5	6	1	12	—	—	—	—
Total customers	875	643	657	2,175	870	640	651	2,161	5	3	6	14

	Three Months Ended June 30,		Six Months Ended June 30,	
Volumes (MMcf)	2017	2016	2017	2016
Natural gas sales				
Residential	11,995	10,576	62,129	62,262
Commercial and industrial	5,027	4,330	19,186	18,818
Wholesale and public authority	333	338	987	1,281
Total volumes sold	17,355	15,244	82,302	82,361
Transportation	49,087	49,601	110,178	108,821
Total volumes delivered	66,442	64,845	192,480	191,182

Total volumes sold increased slightly due to colder weather for the three months ended June 30, 2017, compared with the same period last year. The impact of weather on residential and commercial net margin is mitigated by weather-normalization mechanisms in all jurisdictions.

Wholesale sales represent contracted natural gas volumes that exceed the needs of our residential, commercial and industrial customer base and are available for sale to other parties. The impact to net margin from changes in volumes associated with these customers is minimal.

	Three Months Ended June 30,						
	2017		2016		2017 vs. 2016	2017	2016
Heating Degree Days	Actual	Normal	Actual	Normal	Actual Variance	Actual as a percent of Normal	
Oklahoma	182	191	162	191	12 %	95%	85%
Kansas	345	419	320	411	8 %	82%	78%
Texas	29	53	45	51	(36)%	55%	88%

	Six Months Ended June 30,						
	2017		2016		2017 vs. 2016	2017	2016
Heating Degree Days	Actual	Normal	Actual	Normal	Actual Variance	Actual as a percent of Normal	
Oklahoma	1,574	1,966	1,727	1,966	(9)%	80%	88%
Kansas	2,331	2,922	2,440	2,913	(4)%	80%	84%
Texas	658	1,062	899	1,034	(27)%	62%	87%

Normal HDDs are established through rate proceedings in each of our rate jurisdictions for use primarily in weather-normalization billing calculations. See further discussion on weather normalization in our Regulatory Overview section in Part 1, Item 1, “Business,” of our Annual Report. Normal HDDs disclosed above are based on:

- 10-year weighted average HDDs as of December 31, 2014, for years 2005-2014, as calculated using 11 weather stations across Oklahoma and weighted on average customer count for Oklahoma;
- 30-year average for years 1981-2010 published by the National Oceanic and Atmospheric Administration, as calculated using 4 weather stations across Kansas and weighted on HDDs by weather station and customers for Kansas; and

- an average of HDDs authorized in our most recent rate proceeding in each jurisdiction, and weighted using a rolling 10-year average of actual natural gas distribution sales volumes by jurisdiction for Texas.

Actual HDDs are based on the quarter-to-date and year-to-date, weighted average of:

- 11 weather stations and customers by month for Oklahoma;
- 4 weather stations and customers by month for Kansas; and
- 9 weather stations and natural gas distribution sales volumes by service area for Texas.

Through March 31, 2017, Kansas Gas Services' WNA clause required it to accrue the variation in net margin resulting from actual weather differing from normal weather occurring from November through March. Beginning in April 2017, Kansas Gas Services' WNA clause requires an accrual each month of the year.

CONTINGENCIES

We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

General - We have relied primarily on operating cash flow and commercial paper for our liquidity and capital resource requirements. We fund operating expenses, working capital requirements, including purchases of natural gas, and capital expenditures primarily with cash from operations and commercial paper.

We believe that the combination of the significant residential component of our customer base, the fixed-charge component of our natural gas sales net margin and our regulatory rate mechanisms that we have in place result in a stable cash flow profile. Because the energy consumption of residential customers is less volatile compared with commercial and industrial customers, our business historically has generated stable and predictable net margin and cash flows. Additionally, we have several regulatory rate mechanisms in place to reduce the lag in earning a return on our capital expenditures. We anticipate that our cash flow generated from operations and our expected short- and long-term financing arrangements will enable us to maintain our current and planned level of operations and provide us flexibility to finance our infrastructure investments.

Our ability to access capital markets for debt and equity financing under reasonable terms depends on market conditions and our financial condition and credit ratings. We believe that stronger credit ratings will provide a significant advantage to our business. By maintaining a conservative financial profile and stable revenue base, we believe that we will be able to maintain an investment-grade credit rating, which we believe will provide us access to diverse sources of capital at favorable rates in order to finance our infrastructure investments.

Short-term Financing - The ONE Gas Credit Agreement, which is scheduled to expire in January 2019, contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas' total debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. At June 30, 2017, our total debt-to-capital ratio was 40 percent, and we were in compliance with all covenants under the ONE Gas Credit Agreement.

We have a commercial paper program under which we may issue unsecured commercial paper up to a maximum amount of $700 million to fund short-term borrowing needs. The maturities of the commercial paper notes may vary but may not exceed 270 days from the date of issue. The commercial paper notes are generally sold at par less a discount representing an interest factor.

The ONE Gas Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONE Gas Credit Agreement. At June 30, 2017, we had $79.0 million in short-term borrowings and $1.8 million in letters of credit issued under the ONE Gas Credit Agreement. At June 30, 2017, we had approximately $5.1 million of cash and cash equivalents and $619.2 million of remaining credit available under the ONE Gas Credit Agreement. The total amount of short-term borrowings authorized by ONE Gas' Board of Directors is $1.2 billion.

Long-Term Debt - The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding Senior Notes to declare those Senior Notes immediately due and payable in full.

Credit Ratings - Our credit ratings as of June 30, 2017, were:

Rating Agency	Rating	Outlook
Moody's	A2	Stable
S&P	A-	Positive

Our commercial paper is currently rated Prime-1 by Moody's and A-2 by S&P. We intend to maintain strong credit metrics while we pursue a balanced approach to capital investment and a return of capital to shareholders via a dividend that we believe will be competitive with our peer group.

Pension and Other Postemployment Benefit Plans - Information about our pension and other postemployment benefits plans, including anticipated contributions, is included under Note 11 of the ONE Gas Notes to the Financial Statements in our Annual Report. See Note 8 of the Notes to the Financial Statements in this Quarterly Report for additional information.

CASH FLOW ANALYSIS

We use the indirect method to prepare our Statements of Cash Flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments and changes in our assets and liabilities not classified as investing or financing activities during the period. Items that impact net income but may not result in actual cash receipts or payments include, but are not limited to, depreciation and amortization, deferred income taxes, share-based compensation expense and provision for doubtful accounts.

The following table sets forth the changes in cash flows by operating, investing and financing activities for the periods indicated:

	Six Months Ended June 30,		Variance
	2017	2016	2017 vs. 2016
	(Millions of dollars)		
Total cash provided by (used in):			
Operating activities	$279.3	$276.2	$ 3.1
Investing activities	(154.3)	(144.2)	(10.1)
Financing activities	(134.6)	(80.1)	(54.5)
Change in cash and cash equivalents	(9.6)	51.9	(61.5)
Cash and cash equivalents at beginning of period	14.7	2.4	12.3
Cash and cash equivalents at end of period	$5.1	$54.3	$ (49.2)

Operating Cash Flows - Changes in cash flows from operating activities are due primarily to changes in net margin and operating expenses discussed in Financial Results and Operating Information. Changes in natural gas prices and demand for our services or natural gas, whether because of general economic conditions, changes in supply or increased competition from other service providers, could affect our earnings and operating cash flows. Typically, our cash flows from operations are greater in the first half of the year compared with the second half of the year.

Before considering the impacts of operating asset and liability changes, cash flows were higher for the six months ended June 30, 2017, compared with the same period in 2016, due primarily to an increase in net income, higher noncash expenses for depreciation and amortization and deferred income taxes. The decrease in operating asset and liability changes partially offset these increases. Working capital changes related to accounts receivable and natural gas in storage were impacted by higher costs of natural gas in the first six months of 2017, compared with the same period in 2016. Additionally, we collected a tax receivable in 2016 related to the extension of the IRS rules for bonus depreciation in late 2015.

Investing Cash Flows - Cash used in investing activities increased for the six months ended June 30, 2017, compared with the prior period, due primarily to an increase in capital expenditures related to increased system integrity activities and extending service to new areas during the six months ended June 30, 2017.

Financing Cash Flows - Cash used in financing activities increased for the six months ended June 30, 2017, compared with the prior period, due primarily to larger repayments of notes payable and an increase in the dividend rate of seven cents compared with the same period in 2016, offset by the purchase of fewer shares of treasury stock.

ENVIRONMENTAL, SAFETY AND REGULATORY MATTERS

Environmental Matters - We are subject to multiple historical, wildlife preservation and environmental laws and/or regulations that affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetland preservation, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. In addition, emission controls and/or other regulatory or permitting mandates under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental investigation, and remediation compliance to-date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during the three and six months ended June 30, 2017 and 2016.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured gas sites in Kansas. These sites contain contaminants generally associated with manufactured gas sites and are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE governs all work at these sites. The terms of the consent agreement require us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation typically involves the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater.

We have completed or addressed removal of the source of soil contamination at 11 of the 12 sites, and continue to monitor groundwater at eight of the 12 sites according to plans approved by the KDHE. Regulatory closure has been achieved at three of the 12 sites, but these sites remain subject to potential future requirements that may result in additional costs. During 2016, we completed a site assessment at the twelfth site where no active soil remediation has occurred. We have submitted a work plan to the KDHE for approval to address a source of contamination and associated contaminated soil on a portion of this site. We are also conducting a study of the feasibility of various options to address the remainder of the site. Costs associated with the remediation at this site are not expected to be material to our results of operations or financial position.

With regard to one of our former manufactured gas sites, periodic monitoring and a 2016 interim site investigation indicated elevated levels of contaminants generally associated with manufactured gas sites. Additional testing and work plan development is underway in 2017 to determine a remediation work plan to present to the KDHE for approval, which could impact our estimates of the cost of remediation at this site. In the fourth quarter of 2016, we estimated the potential costs associated with additional investigation and remediation to be in the range of $4.0 million to $7.0 million. A single reliable estimate of the remediation costs is not feasible due to the amount of uncertainty in the ultimate remediation approach that will be utilized. Accordingly, we recorded a reserve of $4.0 million for this site in the fourth quarter of 2016.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during the three and six months ended June 30, 2017 and 2016. A number of environmental issues may exist with respect to manufactured gas sites that are unknown to us. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation required, changing technology and governmental regulations, and to the extent not recovered by insurance or recoverable in rates from our customers, could be material to our financial condition, results of operations or cash flows.

With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us that are subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully recovered by insurance or recoverable in rates from our customers, and those costs may adversely affect our financial condition, results of operations and cash flows. We do not expect expenditures for these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including integrity-management regulations. PHMSA regulations require pipeline companies operating high-pressure transmission pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act was signed into law. The law increased maximum penalties for violating federal pipeline safety regulations and directs the DOT and the Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include, but are not limited to, the following:

- an evaluation of whether natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;
- a verification of records for pipelines in class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and
- a requirement to test previously untested pipelines operating above 30 percent yield strength in high-consequence areas.

In April 2016, PHMSA published a NPRM, the Safety of Gas Transmission & Gathering Lines Rule, in the Federal Register to revise pipeline safety regulations applicable to the safety of onshore natural gas transmission and gathering pipelines. Proposals include changes to pipeline integrity management requirements and other safety-related requirements. The NPRM comment period ended July 7, 2016, and comments are under review by PHMSA. As part of the comment review process, PHMSA is being advised by the Technical Pipeline Safety Standards Committee, informally known by PHMSA as the GPAC, a statutorily mandated advisory committee that advises PHMSA on proposed safety policies for natural gas pipelines. The GPAC reviews PHMSA's proposed regulatory initiatives to assure the technical feasibility, reasonableness, cost-effectiveness and practicality of each proposal. The potential capital and operating expenditures associated with compliance with the proposed rule are currently being evaluated and could be significant depending on the final regulations.

Air and Water Emissions - The Clean Air Act, the Clean Water Act, analogous state laws and/or regulations promulgated thereunder, impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air-pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. We do not expect that these expenditures will have a material impact on our results of operations, financial position or cash flows. The Clean Water Act imposes substantial potential liability for the removal of pollutants discharged to waters of the United States and remediation of waters affected by such discharge.

International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to regulate greenhouse gas emissions. We monitor relevant legislation and regulatory initiatives to assess the potential impact on our operations. The EPA’s Mandatory Greenhouse Gas Reporting Rule requires annual greenhouse gas emissions reporting as carbon dioxide equivalents from affected facilities and for the natural gas delivered by us to our natural gas distribution customers who are not otherwise required to report their own emissions. The additional cost to gather and report this emission data did not have, and we do not expect it to have, a material impact on our results of operations, financial position or cash flows. In addition, Congress has considered, and may consider in the future, legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. Likewise, the EPA may institute additional regulatory rulemaking associated with greenhouse gas emissions. At this time, no rule or legislation has been enacted for natural gas distribution that assesses any costs, fees or expenses on any of these emissions.

CERCLA - CERCLA, also commonly known as Superfund, imposes strict, joint and several liability, without regard to fault or the legality of the original act, on certain classes of “persons” (defined under CERCLA) that caused and/or contributed to the release of a hazardous substance into the environment. These persons include, but are not limited to, the owner or operator of a facility where the release occurred and/or companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies. We do not expect that our responsibilities under CERCLA will have a material impact on our results of operations, financial position or cash flows.

Pipeline Security - The U.S. Department of Homeland Security's Transportation Security Administration issued updated pipeline security guidelines in April 2012. Our pipeline facilities have been reviewed according to the current guidelines and no material changes have been required to date.

Environmental Footprint - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (1) developing and maintaining an accurate greenhouse gas emissions inventory according to current rules issued by the EPA; (2) improving the integrity of our various pipelines; (3)

following developing technologies for emission control; and (4) utilizing practices to reduce the loss of methane from our facilities.

We participate in the EPA’s Natural Gas STAR Program to voluntarily reduce methane emissions. We continue to focus on maintaining low rates of lost-and-unaccounted-for natural gas through expanded implementation of best practices to limit the release of natural gas during pipeline and facility maintenance and operations. Additionally, in March 2016, we were one of 40 founding partners to launch the EPA’s Natural Gas STAR Methane Challenge Program, whereby oil and natural gas companies agree to promote and track commitments to reduce methane emissions beyond what is federally required. Our Methane Challenge Program commitment to annually replace or rehabilitate at least two percent of our combined inventory of cast iron and noncathodically-protected steel pipe aligns with our planned system integrity expenditures for infrastructure replacements. We anticipate reporting in 2018 our calendar year 2017 performance relative to our commitment.

Additional information about our environmental matters is included in the section entitled “Environmental Matters” in Note 9 of the Notes to the Financial Statements in this Quarterly Report.

Regulatory - Several regulatory initiatives impacted the earnings and future earnings potential of our business. See additional information regarding our regulatory initiatives in Management’s Discussion and Analysis of Financial Condition and Results of Operations.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of new accounting standards, if any, is included in Note 1 of the Notes to the Financial Statements in this Quarterly Report.

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The preparation of our financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates.

Information about our estimates and critical accounting policies is included under Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations, “Estimates and Critical Accounting Policies,” in our Annual Report.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Quarterly Report are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The forward-looking statements relate to our anticipated financial performance, liquidity, management’s plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Quarterly

Report identified by words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “should,” “goal,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled,” and other words and terms of similar meaning.

One should not place undue reliance on forward-looking statements, which are applicable only as of the date of this Quarterly Report. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- our ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our regulated rates;
- our ability to manage our operations and maintenance costs;

- changes in regulation of natural gas distribution services, particularly those in Oklahoma, Kansas and Texas;
- the economic climate and, particularly, its effect on the natural gas requirements of our residential and commercial industrial customers;
- competition from alternative forms of energy, including, but not limited to, electricity, solar power, wind power, geothermal energy and biofuels;
- conservation efforts of our customers;
- variations in weather, including seasonal effects on demand, the occurrence of storms and disasters, and climate change;
- indebtedness could make us more vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantage compared with competitors;
- our ability to secure reliable, competitively priced and flexible natural gas transportation and supply, including decisions by natural gas producers to reduce production or shut-in producing natural gas wells and expiration of existing supply, and transportation and storage arrangements that are not replaced with contracts with similar terms and pricing;
- the mechanical integrity of facilities operated;
- operational hazards and unforeseen operational interruptions;
- adverse labor relations;
- the effectiveness of our strategies to reduce earnings lag, margin protection strategies and risk mitigation strategies;
- our ability to generate sufficient cash flows to meet all our cash needs;
- changes in the financial markets during the periods covered by the forward-looking statements, particularly those affecting the availability of capital and our ability to refinance existing debt and fund investments and acquisitions;
- actions of rating agencies, including the ratings of debt, general corporate ratings and changes in the rating agencies' ratings criteria;
- changes in inflation and interest rates;
- our ability to recover the costs of natural gas purchased for our customers;
- impact of potential impairment charges;
- volatility and changes in markets for natural gas;
- possible loss of LDC franchises or other adverse effects caused by the actions of municipalities;
- payment and performance by counterparties and customers as contracted and when due;
- changes in existing or the addition of new environmental, safety, tax and other laws, rules and regulations to which we and our subsidiaries are subject;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- advances in technology;
- population growth rates and changes in the demographic patterns of the markets we serve;
- acts of nature and the potential effects of threatened or actual terrorism, including war;
- cyber attacks or breaches of technology systems or information, affecting us, our customers or vendors;
- the sufficiency of insurance coverage to cover losses;
- the effects of our strategies to reduce tax payments;
- the outcomes, timing and effects of litigation and regulatory investigations, proceedings, including our rate cases, or inquiries;
- changes in accounting standards;
- changes in corporate governance standards;
- discovery of material weaknesses in our internal controls;
- our ability to comply with all covenants in our indentures and the ONE Gas Credit Agreement, a violation of which, if not cured in a timely manner, could trigger a default of our obligations;
- our ability to attract and retain talented employees, management and directors;
- declines in the discount rates on, declines in the market value of the debt and equity securities of, and increases in funding requirements for, our defined benefit plans;
- the ability to successfully complete merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or

divestiture;

- the final resolutions or outcomes with respect to our contingent and other corporate liabilities related to the natural gas distribution business and any related actions for indemnification made pursuant to the Separation and Distribution Agreement with ONEOK; and
- the costs associated with increased regulation and enhanced disclosure and corporate governance requirements pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Item 1A, Risk Factors, in our Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our quantitative and qualitative disclosures about market risk are consistent with those discussed in Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk, in our Annual Report.

Commodity Price Risk

Our commodity price risk, driven primarily by fluctuations in the price of natural gas, is mitigated by our purchased-gas cost adjustment mechanisms. Additionally, we inject natural gas into storage during the summer months and withdraw the natural gas during the winter heating season. Pursuant to programs that are approved by our regulatory authorities, we use derivative instruments to mitigate the volatility of natural gas prices for anticipated natural gas purchases during the winter heating months. Premiums paid and any cash settlements received associated with these derivative instruments are included in, and recoverable through our purchased-gas cost adjustment mechanisms.

Interest-Rate Risk

We would be exposed to interest-rate risk with any new debt financing. We are able to manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps may be used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps may be used to convert the fixed rates of long-term borrowings into short-term variable rates.

Counterparty Credit Risk

We assess the creditworthiness of our customers. Those customers who do not meet minimum standards are required to provide security, including deposits and other forms of collateral, when appropriate. With more than 2 million customers across three states, we are not exposed materially to a concentration of credit risk. We maintain a provision for doubtful accounts based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. In Oklahoma, Kansas and most jurisdictions we serve in Texas, we are able to recover the natural gas cost component of our uncollectible accounts through our purchased-gas cost adjustment mechanisms.

ITEM 4. CONTROLS AND PROCEDURES

Quarterly Evaluation of Disclosure Controls and Procedures - Our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer) have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report based on the evaluation of the controls and procedures required by Rules 13(a)-15(b) of the Exchange Act.

Changes in Internal Control Over Financial Reporting - In the three months ended June 30, 2017, we implemented a new accounts payable system that electronically captures invoice data and provides electronic routing for invoice approvals.
The implementation of this new system is part of ONE Gas' continuing efforts to take advantage of new technology that creates operating efficiencies and was not implemented as a result of any identified deficiencies in internal

controls over financial reporting. While there are inherent risks involved with the implementation of new systems and changes have taken place in internal controls associated with the transition to the new system, management believes it is adequately monitoring and managing the transition.

Other than described above, there have been no changes in our internal control over financial reporting during the three months ended June 30, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows.

ITEM 1A. RISK FACTORS

Our investors should consider the risks set forth in Part I, Item 1A, Risk Factors, of our Annual Report that could affect us and our business. Although we have tried to discuss key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the discussion of risks and the other information included or incorporated by reference in this Quarterly Report, including "Forward-Looking Statements," which are included in Part I, Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth information relating to our purchases of our common stock for the periods indicated:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs	
April 1 - 30, 2017	—	—	—		
May 1 - 31, 2017	203,929	$68.53	203,929		
June 1 - 30, 2017	15,244	70.00	15,244		
Total	219,173	$68.63	219,173	$7,255,651	(a)

(a) - In February 2015, our Board of Directors established an annual limit of $20 million of treasury stock purchases, plus funds received through the dividend reinvestment, direct stock purchase and employee stock purchase plans. Stock purchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we may purchase, and we can terminate or limit the program at any time.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Readers of this report should not rely on or assume the accuracy of any representation or warranty or the validity of any opinion contained in any agreement filed as an exhibit to this Quarterly Report, because such representation, warranty or opinion may be subject to exceptions and qualifications contained in separate disclosure schedules, may represent an allocation of risk between parties in the particular transaction, may be qualified by materiality standards that differ from what may be viewed as material for securities law purposes, or may no longer continue to be true as of any given date. All exhibits attached to this Quarterly Report are included for the purpose of complying with requirements of the SEC. Other than the certifications made by our officers pursuant to the Sarbanes-Oxley Act of 2002 included as exhibits to this Quarterly Report, all exhibits are included only to provide information to investors regarding their respective terms and should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

The following exhibits are filed as part of this Quarterly Report:

Exhibit No.	Exhibit Description
10.1	ONE Gas, Inc. Annual Officer Incentive Plan (incorporated by reference to Appendix A to ONE Gas, Inc.'s Definitive Proxy Statement on Schedule 14A filed on April 5, 2017 (File No. 1-36108)).
31.1	Certification of Pierce H. Norton II pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Curtis L. Dinan pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Pierce H. Norton II pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Curtis L. Dinan pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
101.INS	XBRL Instance Document.
101.SCH	XBRL Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.LAB	XBRL Label Linkbase Document.
101. PRE	XBRL Presentation Linkbase Document.
101.DEF	XBRL Extension Definition Linkbase Document.

Attached as Exhibit 101 to this Quarterly Report are the following XBRL-related documents: (i) Document and Entity Information; (ii) Statements of Income for the three and six months ended June 30, 2017 and 2016; (iii) Statements of Comprehensive Income for the three and six months ended June 30, 2017 and 2016; (iv) Balance Sheets at June 30, 2017 and December 31, 2016; (v) Statements of Cash Flows for the six months ended June 30, 2017 and 2016; (vi) Statement of Equity for the six months ended June 30, 2017; and (vii) Notes to the Financial Statements.

We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Quarterly Report.

SIGNATURE

Pursuant to the requirements of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: August 1, 2017 ONE Gas, Inc.
Registrant

By: /s/ Curtis L. Dinan
Curtis L. Dinan
Senior Vice President,
Chief Financial Officer and Treasurer
(Principal Financial Officer)

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llion of liabilities related to the acquired property. During the third quarter of 2005, PVR began constructing a new 600-ton per hour coal processing plant and rail loading facility on the acquired property and expects to complete construction in the third quarter of 2006 at an estimated total capital expenditure of approximately $14 million to $15 million. Since acquiring fee ownership and lease rights to the property s coal reserves in July 2005, PVR has made cumulative capital expenditures of $15.4 million related to the construction of the plant as of September 30, 2006. The reserves have been leased to an operator who will commence the mining of raw coal on a limited basis during construction of the preparation and loading facility. After completion of the plant, PVR expects the operator s production from the property to increase to approximately one million tons of coal per year in 2007. PVR also expect to earn fees from third party operators for coal processed from adjacent properties.

Green River Acquisition. In July 2005, PVR also acquired fee ownership of approximately 94 million tons of coal reserves located along the Green River in the western Kentucky portion of the Illinois Basin for $62.4 million in cash and the assumption of $3.3 million of deferred income. This coal reserve acquisition was PVR s first in the Illinois Basin and was funded with long-term debt under PVR s revolving credit facility. Currently, approximately 43 million tons of these coal reserves are leased to affiliates of Peabody Energy Corporation. PVR expects the remaining coal reserves to be leased over the next several years, with a gradual increase in coal production and related cash flow from the property.

Huff Creek Acquisition. In May 2006, PVR acquired from Huff Creek Energy Company and Appalachian Coal Holdings, Inc. the lease rights to approximately 69 million tons of coal reserves located on approximately 20,000 acres in Logan, Boone and Wyoming Counties, West Virginia. The purchase price was $65.0 million and was funded with long-term debt under PVR s revolving credit facility.

Natural Gas Midstream Segment

Cantera Acquisition. On March 3, 2005, PVR completed its acquisition of Cantera Gas Resources, LLC, a midstream gas gathering and processing company with primary locations in the mid-continent area of Oklahoma and the panhandle of Texas. Cash paid in connection with the acquisition was $199.2 million, net of cash received and including capitalized acquisition costs, which PVR funded with a $110 million term loan and with long-term debt under its revolving credit facility. PVR used the proceeds from its sale of common units in a subsequent public offering in March 2005 to repay its term loan in full and to reduce outstanding indebtedness under its revolving credit facility.

Transwestern Acquisition. On June 30, 2006 PVR completed its acquisition of 115 miles of pipelines and related compression facilities in Texas and Oklahoma from Transwestern Pipeline Company. These assets complement PVR s existing midstream systems in the area. PVR paid approximately $15 million cash for the acquisition. Subsequently, PVR borrowed $15 million under its revolving credit facility to replenish the cash used for this transaction.

Results of PVR s Operations

The following table sets forth a summary of certain financial data for the periods indicated.

	For the Fiscal Year Ended December 31,		% Change	For the Fiscal Year Ended December 31,	% Change	For the Nine Months Ended September 30,		% Change 2005
	2005 (a)	2004 (a)	2004 to 2005	2003	2003 to 2004	2006 (a)	2005 (a)	to 2006
	(in millions, except per unit data)							
Revenues	$ 446.3	$ 75.6	490%	$ 55.6	36%	$ 390.1	$ 284.2	37%
Expenses	$ 368.3	$ 35.1	949%	$ 29.1	21%	$ 312.7	$ 227.0	38%
Operating income	$ 78.1	$ 40.5	93%	$ 26.6	52%	$ 77.4	$ 57.2	35%
Net income (loss)	$ 51.2	$ 34.3	49%	$ 22.7	51%	$ 52.9	$ 36.8	44%
Net income (loss) per limited partner unit, basic and diluted	$ 2.43	$ 1.86	31%	$ 1.24	50%	$ 1.15	$ 0.90	28%
Cash flows provided by operating activities	$ 93.7	$ 54.8	71%	$ 41.1	33%	$ 75.4	$ 71.7	5%

(a) The significant increases in revenues, expenses and operating income were primarily due to operations from our natural gas midstream segment which PVR acquired in March 2005.

The increase in net income for the nine months ended September 30, 2006 compared to the same period in 2005 was primarily attributable to a $20.2 million increase in operating income which was partially offset by a $3.6 million increase in interest expense for borrowings used to fund acquisitions. Operating income increased in the nine months ended September 30, 2006, primarily due to the contribution of the natural gas midstream business that PVR acquired in March 2005 and increased coal royalty revenue resulting from higher coal prices and increased coal production.

The increase in 2005 net income compared to 2004 net income was primarily attributable to increased operating income, which was partially offset by a $14.0 million noncash net charge to earnings for unrealized losses on derivatives in PVR s natural gas midstream segment and a $6.7 million increase in interest expense. Operating income increased in 2005 primarily due to increased coal royalty revenues resulting from higher commodity prices and related services income and the contribution of the natural gas midstream business that was acquired in March 2005.

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Coal Segment

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

The following table sets forth a summary of certain financial and other data for PVR s coal segment and the percentage change for the periods indicated:

	Nine Months Ended September 30,		
	2006	**2005**	**% Change**
	(dollars in thousands, except per ton amounts)		
Revenues:			
Coal royalties	$ 73,288	$ 60,921	20%
Coal services	4,345	3,869	12%
Other	5,482	4,638	18%
Total revenues	83,115	69,428	20%
Expenses:			
Operating	5,561	4,104	36%
Taxes other than income	565	727	(22%)
General and administrative	6,796	5,962	14%
Depreciation, depletion and amortization	15,050	13,440	12%
Total expenses	27,972	24,233	15%
Operating income	$ 55,143	$ 45,195	22%
Operating Statistics:			
Royalty coal tons produced by lessees (tons in thousands)	24,467	22,496	9%
Average royalty per ton ($/ton)	$ 3.00	$ 2.71	11%

Revenues. Coal royalty revenues increased to $73.3 million for the nine months ended September 30, 2006 from $60.9 million, or 20%, for the same period in 2005, due to a higher average royalty per ton and increased production. The average royalty per ton increased to $3.00 for the nine months ended September 30, 2006 from $2.71 for the nine months ended September 30, 2005. The increase in the average royalty per ton was primarily due to a greater percentage of coal being produced from certain price-sensitive leases and stronger market conditions for coal resulting in higher prices. Coal production by PVR s lessees increased primarily due to production on its Illinois Basin property, which PVR acquired in the third quarter of 2005, and production on our central Appalachian property due to the Huff Creek acquisition in May 2006.

Other revenues increased primarily due to the following factors. In the nine months ended September 30, 2006 and 2005, PVR earned approximately $1.3 million and $0.3 million, respectively, in revenues for the management of certain coal properties. In the nine months ended September 30, 2006, PVR recognized approximately $0.7 million of forfeiture income from lessees with rolling recoupment periods. There was virtually no forfeiture income in the same period of 2005. In the nine months ended September 30, 2006 and 2005, PVR recognized approximately $0.6 million and $0.2 million, respectively, in railcar rental income related to railcars purchased in June 2005. In the nine months ended September 30, 2006 and 2005, PVR recognized approximately $1.3 million and $1.0 million of wheelage fees, respectively, primarily as a result of the Alloy Acquisition. In the nine months ended September 30, 2005, PVR received $1.5 million from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents.

Expenses. Operating expenses increased to $5.6 million, or 37%, for the nine months ended September 2006 compared to $4.1 million for the nine months ended September 30, 2005 due to production on PVR s subleased central Appalachian property acquired in the Huff Creek Acquisition in May 2006. This increase was partially offset by a decrease in production from other subleased properties primarily resulting from the movement of longwall mining operations at one of these properties. Fluctuations in production on subleased properties have a direct impact on royalty expense. General and administrative expenses increased due to absorbing operations related to PVR s 2005 and 2006 acquisitions, increased professional fees and payroll costs relating to evaluating acquisition opportunities and increased reimbursement to PVR s general partner for shared corporate overhead costs. Depreciation, depletion and amortization expense increased due to the increase in production and a higher depletion rate on recently acquired reserves.

Fiscal Year Ended December 31, 2005 Compared to Fiscal Year Ended December 31, 2004

The following table sets forth a summary of certain financial and other data for PVR s coal segment and the percentage change for the periods indicated:

	Fiscal Year Ended December 31,		
	2005	**2004**	**% Change**
	(dollars in thousands, except per ton amounts)		
Revenues:			
Coal royalties	$ 82,725	$ 69,643	19%
Coal services	5,230	3,787	38%
Other	7,800	2,200	255%
Total revenues	95,755	75,630	27%
Operating costs and expenses:			
Operating	$ 5,755	$ 7,224	(20%)
Taxes other than income	1,129	948	19%
General and administrative	9,237	8,307	11%
Depreciation, depletion and amortization	17,890	18,632	(4%)
Total operating expenses	34,011	35,111	(3%)
Operating income	$ 61,744	$ 40,519	52%
Operating Statistics:			
Royalty coal tons produced by lessees (tons in thousands)	30,227	31,181	(3%)
Average royalty per ton ($/ton)	$ 2.74	$ 2.23	23%

Revenues. Coal royalty revenues increased to $82.7 million in 2005 from $69.6 million in 2004, or 19%, due to a higher average royalty per ton despite a 3% decrease in production. The average royalty per ton increased 23% to $2.74 in 2005 from $2.23 in 2004. The increase in the average royalty per ton was primarily due to a greater percentage of coal being produced from certain price-sensitive leases and stronger market conditions for coal resulting in higher prices. Coal production by PVR s lessees decreased primarily due to a loss of production resulting from one lessee s longwall mining operation moving off of PVR s property and onto an adjacent third party property in the first quarter of 2005. Production also decreased due to the inability of one lessee s customer to receive shipments because of an operating problem at the customer s power generation facility. These decreases were partially offset by production from property PVR acquired in July 2005 in the Illinois Basin.

Coal service revenues increased 38% to $5.2 million in 2005 from $3.8 million in 2004. The increase in coal services revenues was primarily related to increased equity earnings from the coal handling joint venture in which PVR acquired a 50% interest in July 2004. Increased revenues from two coal handling facilities that began operating in July 2003 and February 2004 also contributed to the increase.

Other revenues increased 255% to $7.8 million in 2005 from $2.2 million in 2004 primarily due to the following factors. PVR received approximately $1.3 million of additional wheelage fees primarily as a result of the Alloy Acquisition in April 2005. PVR also received $1.5 million during the second quarter of 2005 from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents. PVR received approximately $1.4 million of royalty income in 2005 from the oil and natural gas royalty interests acquired in the March 2005 Coal River Acquisition, approximately $0.8 million in fees for the management of certain coal properties and approximately $0.4 million of rental income from railcars purchased in the second quarter of 2005.

Expenses. Operating expenses decreased to $5.8 million in 2005 from $7.2 million in 2004, or 20%, due to a decrease in production from subleased properties, partially offset by new wheelage expenses incurred as a result

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of the April 2005 Alloy Acquisition. Production from subleased properties decreased by 32% to 4.6 million tons in 2005 from 6.8 million tons in 2004. General and administrative expenses increased primarily due to increased accounting and tax related fees and increased payroll costs due to new personnel and wage increases. The decrease in depreciation, depletion and amortization expense is consistent with the decrease in production.

Fiscal Year Ended December 31, 2004 Compared to Fiscal Year Ended December 31, 2003

The following table sets forth a summary of certain financial and other data for PVR s coal segment and the percentage change for the periods indicated:

	Fiscal Year Ended December 31,		
	2004	**2003**	**% Change**
	(dollars in thousands, except per ton amounts)		
Revenues:			
Coal royalties	$ 69,643	$ 50,312	38%
Coal services	3,787	2,111	79%
Other	2,200	3,219	(32%)
Total revenues	75,630	55,642	36%
Expenses:			
Operating	$ 7,224	$ 4,235	71%
Taxes other than income	948	1,256	(25%)
General and administrative	8,307	7,013	18%
Depreciation, depletion and amortization	18,632	16,578	12%
Total expenses	35,111	29,082	21%
Operating income	$ 40,519	$ 26,560	53%
Operating Statistics:			
Royalty coal tons produced by lessees (tons in thousands)	31,181	26,463	18%
Average royalty per ton ($/ton)	$ 2.23	$ 1.90	17%

Revenues. Coal royalty revenues increased to $69.6 million in 2004 from $50.3 million in 2003, or 38%, principally due to increased production by PVR s lessees and higher royalty rates. The increase in the average gross royalty per ton accounted for 54% of the increase in coal royalty revenues and was primarily due to stronger market conditions for coal and the resulting higher coal prices. The increase in production accounted for the remaining 46% of the overall increase in coal royalty revenues. Production increased when, in the first quarter of 2004, one lessee s longwall mining operation moved onto one of PVR s subleased central Appalachia properties from an adjacent third party property. The addition of a new mine operator and new mines in PVR s central Appalachia properties also contributed to increased production.

Coal services revenues increased primarily as a result of start-up operations at two coal handling facilities that began operating in July 2003 and February 2004. Equity earnings from a coal handling joint venture in which PVR acquired a 50% interest in July 2004 also contributed to the increase.

Other revenues decreased primarily due to decreases in minimum rentals and timber revenues. Minimum rental revenues decreased primarily due to the timing of expiring recoupments from PVR s lessees. The amount recognized in 2003 primarily related to four leases. Each of these leases was assigned to a new lessee approved by PVR. The leases were amended at the time of assignment to allow the new lessees additional time to offset actual production against minimum rental payments. Timber revenues decreased due to the timing of a parcel sale of PVR s standing timber in 2003 and poor weather conditions in the second quarter of 2004. These decreases were partially offset by a gain on the 2004 sale of surface property in Virginia.

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Expenses. Operating expenses increased to $7.2 million in 2004 from $4.2 million in 2003, or 71%, due to an increase in production by lessees on PVR s subleased properties. Production from subleased properties increased by 74% to 6.8 million tons in 2004 from 3.9 million tons in 2003. The decrease in taxes other than income was attributable to the assumption by a new lessee of the property tax obligation on PVR s Coal River property for which it had been responsible since the bankruptcy of the initial Coal River lessee. General and administrative expenses increased due to costs related to a secondary public offering for the sale of common units held by an affiliate of Peabody Energy Corporation and increased professional fees and payroll costs relating to evaluating acquisition opportunities and compliance with the Sarbanes-Oxley Act of 2002. Depreciation, depletion and amortization expense increased primarily as a result of increased production and depreciation on PVR s coal services facilities which began operations in July 2003 and February 2004.

Natural Gas Midstream Segment

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

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

The following table sets forth a summary of certain financial and other data for PVR s natural gas midstream segment and the percentage change for the periods indicated:

	Nine Months Ended September 30,		
	2006	2005 (a)	% Change
	(dollars in thousands)		
Revenues:			
Residue gas	$ 199,096	$ 132,245	51%
Natural gas liquids	97,591	74,235	31%
Condensate	7,165	5,386	33%
Gathering and transportation fees	1,488	1,485	0%
Total natural gas midstream revenues	305,340	213,351	43%
Marketing revenue, net	1,666	1,424	17%
Total revenues	307,006	214,775	43%
Expenses:			
Cost of gas purchased	$ 254,615	$ 182,278	40%
Operating	8,388	6,626	27%
Taxes other than income	1,054	930	13%
General and administrative (b)	8,209	4,107	100%
Depreciation and amortization	12,451	8,797	42%
Total operating expenses	284,717	202,738	40%
Operating income	$ 22,289	$ 12,037	85%

Operating Statistics:			
Inlet volumes (MMcf)	39,431	26,963	46%
Midstream processing margin (c)	$ 50,725	$ 31,073	63%

(a) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the purchase of the natural gas midstream business.

(b) Amounts include approximately $1.9 million for the nine months ended September 30, 2006 and approximately $0.3 million for the same period in 2005 as reimbursements to PVR s general partner for management and administrative services provided to PVR.

(c) Midstream processing margin consists of total natural gas midstream revenues minus the cost of natural gas purchased.

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The financial and other data presented in the table above for the nine months ended September 30, 2005 include seven months of operations of PVR s midstream business. One of the primary reasons for the significant differences in PVR s results of operations for the nine months ended September 30, 2006 as compared to the same period in 2005 is that the 2006 data includes nine full months of operations of the midstream business.

Revenues. Revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from inlet volumes received, condensate collected and sold, gathering and other fees primarily from natural gas volumes connected to PVR s gas processing plants and the purchase and resale of natural gas not connected to its gathering systems and processing plants. The increase in natural gas midstream revenues was primarily a result of an additional two months of operations in the first nine months of 2006 and market changes in NGL and natural gas prices. Average pricing for both NGLs and natural gas increased for the comparative periods.

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

Cost of natural gas purchased consisted of amounts payable to third-party producers for natural gas purchased under percentage of proceeds and keep-whole contracts. The increase in the average purchase price for natural gas was primarily due to overall market increases in natural gas prices. Included in cost of natural gas purchased for the nine months ended September 30, 2006, was a $4.6 million non-cash charge to reserve for amounts related to balances assumed as part of the acquisition of PVR s natural gas midstream business. The following table shows a summary of the effects of derivative activities on midstream processing margin:

	Nine Months Ended September 30,	
	2006	**2005**
	(in thousands)	
Midstream processing margin, as reported	$ 50,725	$ 31,073
Derivatives losses (gains) included in midstream processing margin	1,275	428
Midstream processing margin before impact of derivatives	52,000	31,501
Cash settlements on derivatives	(15,405)	(3,303)
Midstream processing margin, adjusted for derivatives	$ 36,595	$ 28,198

General and administrative expenses increased primarily due to an additional two months of operations in the first nine months of 2006, additional personnel added to support the business and increased reimbursement to PVR s general partner for corporate overhead costs.

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Fiscal Year Ended December 31, 2005

PVR began operating in its natural gas midstream segment on March 3, 2005 with the acquisition of Cantera s natural gas midstream business. Below is a discussion of the results of operations of PVR s natural gas midstream segment for the fiscal year ended December 31, 2005.

	Year Ended December 31, 2005 (a)
	(dollars in thousands)
Revenues:	
Residue gas	$ 233,208
Natural gas liquids	106,453
Condensate	7,322
Gathering and transportation fees	1,674
Total natural gas midstream revenues	348,657
Marketing revenue, net	1,936
Total revenues	350,593
Expenses:	
Cost of gas purchased	303,912
Operating	9,347
Taxes other than income	1,268
General and administrative	6,981
Depreciation and amortization	12,738
Total operating expenses	$ 334,246
Operating income	$ 16,347
Operating Statistics:	
Inlet volumes (MMcf)	38,875
Midstream processing margin (b)	$ 44,745

(a) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the purchase of the natural gas midstream business.

(b) Midstream processing margin consists of total natural gas midstream revenues minus the cost of natural gas purchased.

Revenues. Revenues were generated from the sale of residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from inlet volumes received, condensate collected and sold, gathering and other fees primarily from natural gas volumes connected to PVR s gas processing plants and the purchase and resale of natural gas not connected to its gathering systems and processing plants.

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

Cost of natural gas purchased in 2005 consisted of amounts payable to third-party producers for natural gas purchased under percentage of proceeds and keep-whole contracts. The midstream processing margin, consisting of total natural gas midstream revenues minus the cost of natural gas purchased, was $44.7 million.

Operating expenses were $9.3 million in 2005 and included costs directly associated with the operations of PVR s natural gas midstream segment and include direct labor and supervision, property insurance, repair and maintenance expenses, measurement and utilities. These costs are generally fixed across broad volume ranges. The fuel expense to operate pipelines and plants is more variable in nature and is sensitive to changes in volume and commodity prices; however, a the substantial majority of the fuel cost is generally borne by PVR s producers.

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General and administrative expenses for 2005 were $7.0 million and consisted of costs to manage the midstream assets as well as integration costs.

Depreciation and amortization expenses for 2005 included $4.1 million in amortization of intangibles recognized in connection with the acquisition of the natural gas midstream business and $8.6 million of depreciation on property, plant and equipment.

Other

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Interest Expense. Interest expense for the nine months ended September 30, 2006 was $13.8 million as compared to $10.1 million for the same period in 2005, an increase of 37%, primarily due to interest incurred on additional borrowings under PVR s revolving credit facility to finance the acquisition of the natural gas midstream business and coal property acquisitions in 2005 and 2006.

Derivative Losses. Because PVR s natural gas derivatives and a large portion of PVR s NGL derivatives no longer qualified for hedge accounting and to increase clarity in the financial statements, PVR elected to discontinue hedge accounting prospectively for its remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, PVR began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners capital). The net mark-to-market loss on PVR s outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on PVR s reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in oil and gas prices.

Derivative losses were $11.7 million for the nine months ended September 30, 2006, and included an $11.6 million unrealized loss for mark-to-market adjustments and a $0.1 million unrealized loss for changes in hedge effectiveness. The unrealized loss due to changes in fair market value was associated with PVR s derivative contracts that it no longer accounted for using hedge accounting and represented changes in the fair value of PVR s open contracts during the period. The unrealized loss for changes in hedge effectiveness was associated with hedging contracts that PVR accounted for using hedge accounting under SFAS No. 133. Derivative losses for the nine months ended September 30, 2005, included a $13.9 million unrealized loss representing the change in market value of derivative agreements between the time PVR entered into the agreements in January 2005 and the time the derivative agreements qualified for hedge accounting after closing the acquisition of the natural gas midstream business in March 2005.

Fiscal Year Ended December 31, 2005 Compared to Fiscal Year Ended December 31, 2004

Interest Expense. Interest expense for 2005 increased to $14.1 million, or 93% as compared to $7.3 million in 2004 primarily due to interest incurred on additional borrowings to finance the acquisition of the natural gas midstream business and coal property acquisitions in 2005. The increase in interest expense from 2003 to 2004 was primarily due to higher debt levels resulting from the coal handling joint venture investment in July 2004 and bridge loan issue costs that were expensed upon the termination in December 2004 of the bridge loan agreement which PVR entered into during the fourth quarter of 2004 in anticipation of the acquisition of the natural gas midstream business.

Interest Income. Interest income changed only slightly from $1.1 million in 2004 to $1.2 million in 2005, an 8% increase. In June 2005, a note receivable matured, resulting in half a year of interest income compared to a full year in 2004. This decrease was more than offset by interest income earned on cash balances in PVR s new natural gas midstream segment. Interest income decreased from 2003 to 2004 primarily due to the declining principal balance on PVR s note receivable.

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Derivatives Losses. The loss on derivatives was $14.0 million in 2005. There was no derivative loss in 2004. The 2005 loss included a $13.9 million unrealized loss for mark-to-market adjustments on certain derivative agreements, a $0.7 million unrealized loss for mark-to-market adjustments on a natural gas basis swap for which PVR has elected not to use hedge accounting and a $0.6 million net unrealized gain for changes in effectiveness of open commodity price hedges related to the natural gas midstream segment. The $13.9 million unrealized loss primarily represented the change in the market value of derivative agreements between the time PVR entered into the agreements in January 2005 and the time they qualified for hedge accounting after closing the acquisition of the natural gas midstream business in March 2005. When PVR agreed to acquire its natural gas midstream business, it wanted to ensure an acceptable return on the investment. PVR achieved this objective by entering into pre-closing commodity price derivative agreements covering approximately 75% of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in a significant change in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a noncash charge to earnings for the unrealized loss on derivatives. Upon qualifying for hedge accounting, changes in the derivative agreements market value were accounted for as other comprehensive income or loss to the extent they were effective rather than having a direct effect on net income. Cash settlements with the counterparties related to the derivative agreements will occur monthly in the future over the remaining life of the agreements, and PVR will receive a correspondingly higher or lower amount for the physical sale of the commodity over the same period.

Fiscal Year Ended December 31, 2004 Compared to Fiscal Year Ended December 31, 2003

Interest Expense. Interest expense increased 46% from $5.0 million in 2003 to $7.3 million in 2004, primarily due to bridge loan issue costs that were expensed upon the termination of the bridge loan agreement in December 2004 and higher debt levels resulting from the coal handling joint venture investment in July 2004.

Interest Income. Interest income decreased 13% from $1.2 million in 2003 to $1.1 million in 2004, primarily due to the declining principal balance on PVR s note receivable.

PVR Unit Split

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

Conclusion of Subordination Period

The subordination period with respect to 7,649,880 PVR subordinated units expired on October 1, 2006. As a result, all of the outstanding PVR subordinated units converted into PVR common units on a one-for-one basis in accordance with their terms when PVR paid its third quarter distribution on November 14, 2006.

Liquidity and Capital Resources

Liquidity

We rely exclusively on distributions from PVR to fund any cash requirements for our operations. PVR generally satisfies its working capital requirements and funds its capital expenditures and debt service obligations from cash generated from its operations and borrowings under its revolving credit facility. PVR believes that the cash generated from PVR s operations and its borrowing capacity will be sufficient to meet its working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distribution payments. PVR s ability to satisfy its obligations and planned expenditures will depend upon PVR s future operating performance, which will be affected by, among other things, prevailing economic conditions in the coal industry and natural gas midstream market, some of which are beyond PVR s control.

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Cash Flows

Cash provided by operations increased $3.7 million, or 5%, to $75.4 million for the nine months ended September 30, 2006 from $71.7 million for the same period in 2005. The overall increase was primarily attributable to higher average gross coal royalties per ton and accretive cash flows from PVR s natural gas midstream business, which was acquired in March 2005. Cash provided by operations increased $38.9 million, or 71%, to $93.7 million for the year ended December 31, 2005 from $54.8 million for the same period in 2004. The overall increase in cash provided by operations in 2005 compared to 2004 was primarily attributable to higher average gross coal royalties per ton and accretive cash flows from PVR s newly acquired natural gas midstream business. Cash provided by operations increased $13.7 million, or 33%, to $54.8 million for the year ended December 31, 2004 from $41.1 million for the same period in 2003. The overall increase in cash provided by operations in 2004 compared to 2003 was largely due to increased production by PVR s lessees and higher coal royalty rates.

PVR made cash investments during the nine months ended September 30, 2006, primarily for coal reserve acquisitions, coal loadout facility construction and natural gas midstream gathering system expansions. Other investments in the same period of 2005 included the acquisition of PVR s natural gas midstream business, net of cash acquired, and coal reserve acquisitions.

PVR made cash investments in 2005 primarily for its acquisition of the natural gas midstream business and coal reserve acquisitions. Other investments in 2005 included a $4.1 million purchase of railcars that PVR previously leased and $4.4 million of gathering system additions. Cash investments in 2004 primarily related to PVR s investment in the coal handling joint venture with Massey, which has been accounted for as an equity investment. Cash investments in 2003 primarily related to PVR s construction of a new coal loading facility on its Coal River property in West Virginia.

Capital expenditures, including noncash items, for each of the three years ended December 31, 2005 and for the nine months ended September 30, 2005 and 2006, were as follows:

	Year Ended December 31,			Year Ended December 31,		Nine Months Ended September 30,		
	2005	**2004**	**% Change 2004 to 2005**	**2003**	**% Change 2003 to 2004**	**2006**	**2005**	**% Change 2005 to 2006**
	(dollars in thousands)			**(dollars in thousands)**		**(dollars in thousands)**		
Coal:								
Coal reserve and lease acquisitions (a)(b)	$ 106,489	$ 1,293	8136%	$ 6,330	(80)%	$ 66,580	$ 105,474	(37%)
Acquisition of coal handling joint venture interest		28,442	(100%)					
Support equipment and facilities (c)	6,008	855	603%	4,128	79%	13,902	4,896	184%
Total	112,497	30,590	268%	10,458	193%	80,482	110,370	(27%)
Natural gas midstream:								
Acquisitions, net of cash acquired	199,223		100%			14,626	199,091	(93%)
	7,588		100%			13,243	4,719	181%

Other property and equipment expenditures								
Total	206,811					27,869	203,810	(86%)
Total capital expenditures	$ 319,308	$ 30,590	944%	$ 10,458	193%	$ 108,351	$ 314,180	(66%)

(a) Amount in 2005 includes noncash expenditure of $11.1 million to acquire coal reserves in Kentucky in the Wayland Acquisition in exchange for $10.4 million of equity issued in the form of common units and $0.7 million of liabilities assumed. Amount in 2005 also includes the noncash portion of the Green River Acquisition, in which PVR assumed $3.3 million of deferred income. Amounts in 2004 and 2003 include
noncash expenditures of $1.1 million and $5.2 million to acquire additional reserves on PVR s northern Appalachia properties in exchange for equity issued in the form of common and Class B units.
(b) Amount in 2005 includes $0.4 million of noncash expenditures due to the timing of payment of invoices.
(c) Amount in 2005 includes $0.8 million of noncash expenditures due to the timing of payment of invoices.

PVR funded its capital expenditures for the nine months ended September 30, 2006 with cash flows from operations and borrowings under its revolving credit facility. To finance its acquisitions in the nine months ended September 30, 2005, PVR borrowed $140.2 million, net of repayments, received proceeds of $126.5 million from its secondary public offering and received a $2.8 million contribution from its general partner. Distributions to partners increased to $48.0 million in the nine months ended September 30, 2006, from $37.8 million in the nine months ended September 30, 2005, because PVR increased the quarterly distribution per unit.

To finance its 2005 acquisitions, PVR borrowed $137.2 million, net of repayments, received proceeds of $126.4 million from its secondary public offering of common units and received a $2.6 million contribution from its general partner in order to maintain its 2.0% interest in PVR. To finance its equity investment in the Massey coal handling joint venture in 2004, PVR borrowed $26.0 million, net of repayments. In 2003, PVR received $90.0 million in proceeds from a private placement of senior unsecured notes, which PVR used to repay a $43.4 million term loan and to repay most of the outstanding debt on its revolving credit facility at the time. Distributions to partners increased to $51.9 million in 2005 from $39.2 million in 2004 and $36.7 million in 2003 because PVR increased the quarterly distribution per unit.

Long-Term Debt

As of September 30, 2006, PVR had outstanding borrowings of $326.6 million, consisting of $251.8 million borrowed under its revolving credit facility and $74.8 million of senior unsecured notes, or the Notes. The current portion of the Notes as of September 30, 2006, was $10.8 million. As of December 31, 2005, PVR had outstanding borrowings of $255.0 million, consisting of $172.0 million borrowed under its revolving credit facility and $83.0 million of the Notes. The current portion of the Notes as of December 31, 2005, was $8.1 million.

Revolving Credit Facility. Concurrent with the closing of the acquisition of the natural gas midstream business in March 2005, PVR s wholly owned operating company, the parent of PVR Midstream LLC and a subsidiary of PVR, entered into a new unsecured $260 million, five-year credit agreement with a syndicate of financial institutions led by PNC Bank, National Association. The new agreement consisted of a $150 million revolving credit facility that matures in March 2010 and a $110 million term loan. PVR used a portion of the revolving credit facility and the term loan to fund the acquisition of the natural gas midstream business and to repay borrowings under PVR s previous credit facility. Proceeds of $126.4 million received from a subsequent public offering of 2.5 million common units in March 2005 and a $2.6 million contribution from PVR s general partner were used to repay the $110 million term loan and a portion of the amount outstanding under the revolving credit facility. In the fourth quarter of 2004, PVR paid loan issue costs of approximately $1.2 million related to the term loan, which were recorded as interest expense in 2004. The term loan cannot be re-borrowed. The revolving credit facility is available for general PVR partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. In 2005, PVR incurred commitment fees of $0.4 million on the unused portion of the revolving credit facility. As of December 31, 2005 and September 30, 2006, PVR had $172.0 million and $251.8 million, respectively, outstanding under the revolving credit facility.

In July 2005, PVR amended its credit agreement to increase the size of the commitment under the revolving credit facility from $150 million to $300 million and to increase a one-time option (upon receipt by the credit

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facility s administrative agent of commitments from one or more lenders) to expand the revolving credit facility from $100 million to $150 million. The amendment also updated certain debt covenant definitions. The interest rate under the credit agreement remained unchanged and fluctuates based on PVR s ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 1.00% if PVR selects the base rate borrowing option under the credit agreement or at a rate derived from the London Inter Bank Offering Rate (or LIBOR) plus an applicable margin ranging from 1.00% to 2.00% if PVR selects the LIBOR-based borrowing option. The other terms of the credit agreement remained unchanged.

The financial covenants under PVR s revolving credit facility require PVR to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted PVR s additional borrowing capacity under its revolving credit facility to approximately $106.5 million as of December 31, 2005 and approximately $126.2 million as of September 30, 2006. The Revolver prohibits PVR from making distributions to its unitholders if any potential default or event of default, as defined in the revolving credit facility, occurs or would result from the distribution. In addition, the revolving credit facility contains various covenants that limit, among other things, PVR s ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of its business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. As of December 31, 2005 and September 30, 2006, PVR was in compliance with all of its covenants under the revolving credit facility.

Senior Unsecured Notes. As of December 31, 2005 and September 30, 2006, PVR owed $83.0 million and $74.8 million, respectively, under its Notes. The Notes initially bore interest at a fixed rate of 5.77% and mature in March 2013, with semi-annual principal and interest payments. The Notes contain various covenants similar to those contained in the revolving credit facility. The Notes rank *pari passu* in right of payment with all other unsecured indebtedness, including the revolving credit facility. As of December 31, 2005 and September 30, 2006, PVR was in compliance with all of its covenants under the Notes.

In conjunction with the closing of the acquisition of the natural gas midstream business, PVR amended the Notes to allow PVR to enter the natural gas midstream business and to increase certain covenant coverage ratios, including the debt to EBITDA test. In exchange for this amendment, PVR agreed to a 0.25% increase in the fixed interest rate on the Notes, from 5.77% to 6.02%. The amendment to the Notes also requires that PVR obtain an annual confirmation of its credit rating, with a 1.00% increase in the interest rate payable on the Notes in the event its credit rating falls below investment grade. On March 15, 2006, PVR s investment grade credit rating was confirmed by Dominion Bond Rating Services.

Interest Rate Swaps. In September 2005, PVR entered into interest rate swap agreements with notional amounts totaling $60 million to establish a fixed rate on the LIBOR-based portion of the outstanding balance of the revolving credit facility until March 2010 (or the Revolver Swaps). PVR pays a fixed rate of 4.22% on the notional amount, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver Swap agreements were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings in interest expense. After considering the applicable margin of 1.25% in effect as of December 31, 2005 and September 30, 2006, the total interest rate on the $60 million portion of Revolver borrowings covered by the Revolver Swaps was 5.47% at December 31, 2005 and September 30, 2006.

In March 2003, PVR entered into an interest rate swap agreement with an original notional amount of $30 million to hedge a portion of the fair value of the Notes (or the Senior Notes Swap). The Senior Notes Swap agreement was settled on June 30, 2005, for $0.8 million. The settlement was paid in cash by PVR to the counterparty in July 2005. The $0.8 million negative fair value adjustment of the carrying amount of long-term debt will be amortized as interest expense over the remaining term of the Notes using the effective interest rate method.

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Future Capital Needs and Commitments

Part of PVR s strategy is to make acquisitions which increase cash available for distribution to its unitholders. Long-term cash requirements for asset acquisitions are expected to be funded by several sources,

including cash flows from operating activities, borrowings under credit facilities and the issuance of additional equity and debt securities. PVR s ability to make these acquisitions in the future will depend in part on the availability of debt financing and on its ability to periodically use equity financing through the issuance of new common units, which will depend on various factors, including prevailing market conditions, interest rates and its financial condition and credit rating at the time.

PVR anticipates making capital expenditures, excluding acquisitions, in 2007 of $16.4 million. PVR s management intends to fund these capital expenditures with a combination of cash flows provided by operating activities and borrowings under PVR s revolving credit facility, under which PVR had $126.2 million borrowing capacity as of September 30, 2006, and potentially with proceeds from the issuance of additional equity. PVR believes that it will continue to have adequate liquidity to fund future recurring operating and investing activities. Short-term cash requirements, such as operating expenses and quarterly distributions to PVR s general partner and unitholders, are expected to be funded through operating cash flows.

Contractual Obligations

PVR s contractual obligations, as of December 31, 2005, are summarized in the following table:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	Thereafter
	(in thousands)				
Revolving credit facility	$ 172,000	$	$	$ 172,000	$
Senior unsecured notes	83,700	8,300	23,700	27,500	24,200
Rental commitments (a)	3,751	934	1,629	1,188	
Total contractual cash obligations (b)	$ 259,451	$ 9,234	$ 25,329	$ 200,688	$ 24,200

(a) PVR s rental commitments primarily relate to reserve-based properties which are, or are intended to be, subleased by PVR to third parties. The obligation 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. PVR believes that the obligation after five years cannot be estimated with certainty; however, based on historical trends, PVR believes that it will incur approximately $0.6 million in rental commitments in perpetuity until the reserves have been exhausted.

(b) The total contractual cash obligations do not include reimbursements to PVR s general partner. PVR s general partner is entitled to receive reimbursement of direct and indirect expenses incurred on PVR s behalf until PVR is dissolved.

PVR does not have employment agreements with executive officers and does not have any other employees. PVR s compensation obligation with respect to its executive officers can be significantly different from one year to another and is based on variables such as PVR s performance for the given year. For more a more detailed discussion on PVR s executive compensation for the fiscal years ended December 31, 2003, 2004 and 2005, please read Management Penn Virginia Resource Partners, L.P. Compensation of PVR s Executive Officers.

PVR s Off-Balance Sheet Arrangements

At September 30, 2006 and December 31, 2005, PVR 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. PVR is, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise if it had engaged in such relationships.

Summary of Critical Accounting Policies and Estimates Related to PVR s Operations

The process of preparing financial statements in accordance with accounting principles generally accepted in the United States of America requires PVR s 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. PVR considers the following to be the most critical accounting policies which involve the judgment of its management.

Natural Gas Midstream Revenues

Revenue from the sale of NGLs and residue gas is recognized when the NGLs and residue gas produced at PVR s gas processing plants are sold. Gathering and transportation revenue is recognized based upon actual volumes delivered. Due to the time needed to gather information from various purchasers and measurement locations and then calculate volumes delivered, the collection of natural gas midstream revenues may take up to 30 days following the month of production. Therefore, accruals for revenues and accounts receivable and the related cost of gas purchased and accounts payable are made based on estimates of natural gas purchased and NGLs and natural gas sold, and PVR s financial results include estimates of production and revenues for the period of actual production. Any differences, which PVR does not expect to be significant, between the actual amounts ultimately received or paid and the original estimates are recorded in the period they become finalized. Approximately 46% of natural gas midstream revenues in 2005 related to two customers and approximately 40% of natural gas midstream revenues for the nine months ended September 30, 2006 related to two customers.

Coal Royalty Revenues

Coal royalty revenues are recognized on the basis of tons of coal sold by PVR s lessees and the corresponding revenues from those sales. Since PVR does not operate any coal mines, PVR does not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, PVR s financial results include estimated revenues and accounts receivable for the month of production. Any differences, which PVR does not expect to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Derivative Activities

PVR has historically entered into derivative financial instruments that would qualify for hedge accounting under Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities. Hedge accounting affects the timing of revenue recognition and cost of gas purchased in PVR s statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until the hedged transaction occurs. The results reflected in the statement of income are based on the actual settlements with the counterparty. PVR includes this gain or loss in natural gas midstream revenues or cost of midstream gas purchased, depending on the commodity. Because effective January 1, 2006 PVR s natural gas derivatives and a large portion of PVR s NGL derivatives no longer qualified for hedge accounting and to increase clarity in the financial statements, PVR elected to discontinue hedge accounting prospectively for its remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, PVR began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners capital). Because PVR no longer uses hedge accounting for its commodity derivatives, it could experience significant changes in the estimate of derivative gain or loss recognized in revenue and cost of midstream gas purchased due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

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The net mark-to-market loss on PVR s outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on PVR s reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in oil and gas prices.

Depletion

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 PVR s own geologists and outside consultants. PVR s estimates of coal reserves are updated annually and may result in adjustments to coal reserves and depletion rates that are recognized prospectively.

Goodwill

Under SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, goodwill recorded in connection with a business combination is not amortized, but tested for impairment at least annually. Accordingly, PVR does not amortize goodwill. PVR tests goodwill for impairment during the fourth quarter of each fiscal year. Based on the results of PVR s test during the fourth quarter of 2005, no goodwill impairment was recognized in 2005.

Intangibles

Intangible assets are primarily associated with assumed contracts, customer relationships and rights-of-way. These intangible assets are amortized over periods of up to 15 years, the period in which benefits are derived from the contracts, relationships and rights-of-way, and will be reviewed for impairment under SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets.

Recent Accounting Pronouncements

In March 2005, the Financial Accounting Standards Board (or the FASB) released Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (or FIN 47), which provides guidance for applying SFAS No. 143, Accounting for Asset Retirement Obligations. FIN 47 became effective as of December 31, 2005, and PVR recorded an additional liability of $0.6 million as a result of implementing FIN 47, relating to its natural gas midstream segment. The cumulative effect of change in accounting principle of $0.1 million was not material and was included in depreciation, depletion and amortization expense in the statement of income.

In June 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3, which replaces Accounting Principles Board Opinion No. 20, Accounting Changes, and SFAS No. 3, Reporting Accounting Changes in Interim Financial Statements, and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Consequently, PVR adopted the provisions of SFAS 154 for its fiscal year beginning January 1, 2006. The adoption of the provisions of SFAS No. 154 did not have a material impact on PVR s consolidated financial statements.

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Quantitative and Qualitative Disclosures About Market Risk Related to PVR s Operations

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which PVR is exposed are NGL, crude oil, natural gas and coal price risks and interest rate risk.

PVR is also indirectly exposed to the credit risk of its lessees. If PVR s lessees become financially insolvent, its lessees may not be able to continue operating or meeting their minimum lease payment obligations.

Price Risk Management

PVR s 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 its natural gas midstream business. Prior to May 1, 2006, these financial instruments were historically designated as cash flow hedges and accounted for in accordance with SFAS No. 133, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 139. The derivative financial instruments are placed with major financial institutions that PVR believes are of minimum credit risk. The fair value of PVR s price risk management assets is significantly affected by fluctuations in the prices of natural gas, NGLs and crude oil. When PVR agreed to acquire its natural gas midstream business, PVR wanted to ensure an acceptable return on the investment. This objective was supported by entering into pre-closing commodity price derivative agreements covering approximately 75% of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in a significant change in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a $13.9 million noncash charge to earnings for the unrealized loss on these derivatives. Subsequent to the acquisition of the natural gas midstream business, PVR formally designated the agreements as cash flow hedges in accordance with SFAS No. 133. Upon qualifying for hedge accounting, changes in the market value of the derivative agreements are accounted for as other comprehensive income or loss to the extent they are effective, rather than as a direct impact on net income. SFAS No. 133 requires PVR s to continue to measure the effectiveness of the derivative agreements in relation to the underlying commodity being hedged, and PVR will be required to record the ineffective portion of the agreements in its net income for the respective period. For 2005, PVR reported a $0.6 million net unrealized gain on derivatives for the ineffective portion of the agreements as of December 31, 2005. Cash settlements with the counterparties related to the derivative agreements will occur monthly over the life of the agreements, and PVR will receive a correspondingly higher or lower amount for the physical sale of the commodity over the same period. In addition, PVR entered into derivative agreements for NGLs and natural gas to further protect its margins subsequent to the acquisition of the natural gas midstream business. These derivative agreements have been designated as cash flow hedges.

During the nine months ended September 30, 2006, PVR reported a $11.6 million derivative loss for mark-to-market adjustments on certain derivatives that no longer qualified for hedge accounting effective January 1, 2006. Because PVR s natural gas derivatives and a large portion of its NGL derivatives no longer qualify for hedge accounting and to increase clarity in its financial statements, PVR elected to discontinue hedge accounting prospectively for its remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, PVR began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners capital). The net mark-to-market loss on its outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on PVR s reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in oil and gas prices. See the discussion and tables in Note 9 to the Penn Virginia Resource GP, LLC and Subsidiaries Combined Financial Statements included elsewhere in this prospectus for a description of PVR s derivative

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program. The following table lists open mark-to-market derivative agreements and their fair value as of December 31, 2005 and September 30, 2006:

	As of December 31, 2005			
	Average Volume Per Day	Weighted Average Price	Estimated Fair Value	Estimated Fair Value as of September 30, 2006 (Unaudited)
	(in gallons)	(per gallon)	(in thousands)	
Ethane Swaps				
First Quarter 2006 through Fourth Quarter 2006	68,880	$ 0.4770	$ (6,269)	$ (1,251)
First Quarter 2007 through Fourth Quarter 2007	34,440	$ 0.5050	(1,839)	(916)
First Quarter 2008 through Fourth Quarter 2008	34,440	$ 0.4700	(1,442)	(1,026)
	(in gallons)	(per gallon)		
Propane Swaps				
First Quarter 2006 through Fourth Quarter 2006	52,080	$ 0.7060	(5,918)	(1,679)
First Quarter 2007 through Fourth Quarter 2007	26,040	$ 0.7550	(1,679)	(1,709)
First Quarter 2008 through Fourth Quarter 2008	26,040	$ 0.7175	(1,471)	(1,798)
	(in Bbls)	(per Bbl)		
Crude Oil Swaps				
First Quarter 2006 through Fourth Quarter 2006	1,100	$ 44.45	(7,834)	(2,638)
First Quarter 2007 through Fourth Quarter 2007	560	$ 50.80	(2,501)	(3,376)
First Quarter 2008 through Fourth Quarter 2008	560	$ 49.27	(2,313)	(3,653)
	(in barrels)	(per barrel)		
Crude Oil Collars				
Fourth Quarter 2006 (October only)				107
	(in MMbtu)	(per MMbtu)		
Natural Gas Swaps				
First Quarter 2006 through Fourth Quarter 2006	7,500	$ 7.05	9,940	(1,009)
First Quarter 2007 through Fourth Quarter 2007	4,000	$ 6.97	4,474	987
First Quarter 2008 through Fourth Quarter 2008	4,000	$ 6.97	3,126	1,377
			$ (13,726)	$ (16,584)

Interest Rate Risk

As of December 31, 2005 and September 30, 2006, PVR s $83.0 million and $74.8 million, respectively, of outstanding indebtedness under the Notes carried a fixed interest rate throughout its term. PVR executed an interest rate derivative transaction in March 2003 to effectively convert the interest rate on one-third of the amount outstanding under the Notes from a fixed rate of 5.77% to a floating rate of LIBOR plus 2.36%. The interest rate swap was accounted for as a fair value hedge in compliance with SFAS No. 133. The interest rate swap was settled on June 30, 2005, for $0.8 million. The settlement was paid in cash by PVR to the counterparty in July 2005.

As of December 31, 2005 and September 30, 2006, PVR s $172.0 million and $251.8 million, respectively, of outstanding indebtedness under its revolving credit facility carried a variable interest rate throughout its term. PVR executed interest rate derivative transactions in September 2005 to effectively convert the interest rate on $60 million of the amount outstanding under its revolving credit facility from a LIBOR-based floating rate to a fixed rate of 4.22% plus the applicable margin. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133. A 1% increase in short-term interest rates on the floating rate debt outstanding (net of amounts fixed through hedging transactions) at December 31, 2005, and September 30, 2006, would cost us approximately $1.1 million and $1.9 million in additional annual interest expense, net of interest rate swaps.

Environmental Matters Related to PVR s Operations

The operations of PVR s coal lessees and its natural gas midstream segment are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations

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

As of December 31, 2005 and 2004, PVR s environmental liabilities totaled $2.5 million and $1.5 million, respectively. As of September 30, 2006, PVR s environmental liabilities totaled $2.4 million, which represents PVR s best estimate of its liabilities as of that date related to PVR s coal and natural gas midstream businesses. PVR has reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future. For a summary of the environmental laws and regulations applicable to PVR s operations, please see Business of Penn Virginia Resource Partners, L.P. Government Regulation and Environmental Matters Related to PVR s Operations.

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OUR BUSINESS

General

We are a Delaware limited partnership formed in June 2006 that currently owns three types of equity interests in Penn Virginia Resource Partners, L.P. (NYSE: PVR), a publicly traded Delaware limited partnership that is principally engaged in the management of coal properties and the gathering and processing of natural gas.

Our Strategy

Our primary business strategy is to increase our cash distributions to our unitholders. PVR s primary business objective is to create sustainable, capital-efficient growth in distributable cash flow to maximize its cash distributions to its unitholders by expanding its coal property management and natural gas gathering and processing businesses, through both internal growth and acquisitions. We intend to monitor the implementation of PVR s business strategies. Our business strategy includes supporting the growth of PVR by purchasing PVR units or lending funds to PVR to provide funding for acquisitions or for internal growth projects. We may also provide PVR with other forms of credit support, such as guarantees related to financing a project.

Our Interest in PVR

Our only cash generating assets consist of our partnership interests in PVR, which, upon completion of this offering of our common units, will initially consist of the following:

- a 2.0% general partner interest in PVR, which we hold through our 100% ownership interest in Penn Virginia Resource GP, LLC, PVR s general partner;

- all of the incentive distribution rights in PVR, which we hold through our 100% ownership interest in Penn Virginia Resource GP, LLC; and

- 19,152,121 units of PVR, consisting of 15,541,738 common units and 3,610,383 Class B units of PVR, representing an aggregate 41.1% limited partner interest in PVR. We will purchase 416,444 PVR common units and all of the Class B units from PVR using substantially all of the net proceeds of this offering. See Use of Proceeds. For a description of the terms of the Class B units, please read Material Provisions of the Partnership Agreement of Penn Virginia Resource Partners, L.P. Class B Units.

All of our cash flows are generated from the cash distributions we receive with respect to the PVR partnership interests we own. PVR is required by its partnership agreement to distribute, and it has historically distributed within 45 days of the end of each quarter, all of its cash on hand at the end of each quarter, less cash reserves established by its general partner in its sole discretion to provide for the proper conduct of PVR s business or to provide for future distributions. While we, like PVR, are structured as a limited partnership, our capital structure and cash distribution policy differ materially from those of PVR. Most notably, our general partner does not have an economic interest in us and is not entitled to receive any distributions from us and our capital structure does not include incentive distribution rights. Therefore, our distributions are allocated exclusively to our common units, which is our only class of security currently outstanding.

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

13.0% of all incremental cash distributed in a quarter after $0.275 has been distributed in respect of each common unit and Class B unit of PVR for that quarter;

23.0% of all incremental cash distributed after $0.325 has been distributed in respect of each common unit and Class B unit of PVR for that quarter; and

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the maximum sharing level of 48.0% of all incremental cash distributed after $0.375 has been distributed in respect of each common unit and Class B unit of PVR for that quarter.

Since 2001, PVR has increased its quarterly cash distribution eight times from $0.25 per unit ($1.00 on an annualized basis) to $0.40 per unit ($1.60 on an annualized basis), which is the most recently paid distribution. These increased cash distributions by PVR have placed us at the third and maximum target cash distribution level as described above. As a consequence, any increase in cash distribution level from PVR will allow us to share at the 48.0% level and the cash distributions we receive from PVR with respect to our indirect ownership of the incentive distribution rights will increase more rapidly than those with respect to our ownership of the general partner interest and limited partner interests. Because we are at the maximum target cash distribution level on the incentive distribution rights, future growth in distributions we receive from PVR will not result from an increase in the target cash distribution level associated with the incentive distribution rights.

The following graph shows hypothetical cash distributions payable to us with respect to our partnership interests in PVR, including the incentive distribution rights, the general partner interest and the limited partner interests, across a range of hypothetical annualized distributions made by PVR. This information assumes:

PVR has a total of 45,671,357 limited partner units (consisting of 42,060,974 common units and 3,610,383 Class B units) outstanding; and

our ownership of:

the 2% general partner interest in PVR,

100% of the incentive distribution rights in PVR, and

19,152,121 units of PVR, consisting of 15,541,738 common units and 3,610,383 Class B units.

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The graph also illustrates the impact to us of PVR raising or lowering its quarterly cash distribution from the most recently paid distribution of $0.40 per unit ($1.60 on an annualized basis), which was paid on November 14, 2006 with respect to the third quarter of 2006. This information is presented for illustrative purposes only. This information is not intended to be a prediction of future performance and does not attempt to illustrate the impact and changes in our or PVR s business, including changes that may result from changes in interest rates, coal prices, natural gas prices, natural gas liquids (NGL) prices and general economic conditions, or the impact of any acquisition or, expansion projects, divestitures or issuance of additional units or debt.

The impact to us of changes in PVR s cash distribution levels will vary depending on several factors, including the number of PVR s outstanding limited partner units on the record date for cash distributions and the impact of the incentive distribution rights structure. In addition, the level of cash distributions we receive may be affected by risks associated with the underlying business of PVR. Please read Risk Factors.

If PVR is successful in implementing its business strategies and increasing distributions to its partners, we generally would expect to increase distributions to our unitholders, although the timing and amount of any such increase in our distributions will not necessarily be comparable to any increase in PVR s distributions. We cannot assure you that any distributions will be declared or paid by PVR. Please read Our Cash Distribution Policy and Restrictions on Distributions and Risk Factors.

PVR s cash distributions to us will vary depending on several factors, including PVR s total outstanding partnership interests on the record date for the distribution, the per unit distribution and our relative ownership of PVR s partnership interests.

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It is not likely that our common units and PVR s common units will trade in simple relation or proportion to one another. Instead, while the trading prices of our common units and PVR s common units are likely to follow generally similar broad trends, the trading prices may diverge because, among other things:

- with respect to PVR s distributions, PVR s common unitholders have a priority over our incentive distribution rights in PVR;
- we participate in PVR s general partner s distributions and the incentive distribution rights, and PVR s common unitholders do not; and
- we may enter into other businesses separate from PVR or any of its affiliates.

Please see Comparison of Rights of Holders of PVR S Common Units and Our Common Units for a summary comparison of certain features of PVR s common units and our common units.

How Our Partnership Agreement Terms Differ from those of Other Publicly Traded Partnerships

Although we are organized as a limited partnership, the terms of our partnership agreement differ from those of PVR and many other publicly traded partnerships. For example:

- Our general partner is not entitled to incentive distributions. Most publicly traded partnerships have incentive distribution rights that entitle the general partner to receive increasing percentages, commonly up to 50%, of the cash distributed in excess of a certain per unit distribution.
- We do not have subordinated units. Most publicly traded partnerships initially have subordinated units that (i) do not receive distributions in a quarter until all common units receive the minimum quarterly distribution plus arrearages and (ii) convert to common units upon meeting certain financial tests.
- Our general partner is not required to make additional capital contributions to us in connection with additional issuances of units by us because it has no economic interest in us. Most general partners of publicly traded partnerships have a 2% general partner interest and are required to or have the option to make additional capital contributions to the partnership in order to maintain their percentage general partner interest upon issuance of additional partnership interests by the partnership.

You should read the summaries in Description of Our Common Units and Description of Our Partnership Agreement, as well as Appendix A Form of Amended and Restated Agreement of Limited Partnership of Penn Virginia GP Holdings, L.P., for a more complete description of the terms of our partnership agreement.

Legal Proceedings

We are not currently a party to any litigation.

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BUSINESS OF PENN VIRGINIA RESOURCE PARTNERS, L.P.

General

PVR is a publicly traded Delaware limited partnership formed by Penn Virginia Corporation in 2001 that is principally engaged in the management of coal properties and the gathering and processing of natural gas. Both in its current limited partnership form and in its previous corporate form, PVR has managed coal properties since 1882. Since the acquisition of a natural gas midstream business in March 2005, PVR conducts operations in two business segments: coal and natural gas midstream. For the twelve months ended September 30, 2006, approximately 73%, or $71.7 million, of PVR s operating income was attributable to its coal segment, and approximately 27%, or $26.6 million, of its operating income was attributable to its natural gas midstream segment.

The following maps show the general locations of PVR s coal reserves, coal services and infrastructure investments and PVR s natural gas gathering and processing systems:

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The following map shows the locations and general transportation access to PVR s Central Appalachia properties, as well as PVR s coal loading and preparation facilities existing on those properties. PVR s Central Appalachia lessees own addition coal loading and preparation facilities, which are described in the tables on pages 102 and 103 under PVR s Operations Coal Segment.

Coal Segment Overview

As of December 31, 2005, PVR owned or controlled approximately 689 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. As of December 31, 2005, approximately 25% of PVR s proven and probable coal reserves were compliance coal and approximately 48% were low sulfur coal. PVR enters into long-term leases with experienced, third-party mine operators providing them the right to mine its coal reserves in exchange for royalty payments. PVR does not operate any mines. In 2005, PVR s lessees produced 30.2 million tons of coal from PVR s properties and paid PVR coal royalty revenues of $82.7 million, for an average gross coal royalty per ton of $2.74. Approximately 83% of PVR s coal royalty revenues in 2005 and 79% of its coal royalty revenues in 2004 were derived from coal mined on its properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price. The balance of PVR s coal royalty revenues for the respective periods was derived from coal mined on its properties under leases containing fixed royalty rates that escalate annually.

Substantially all of PVR s leases require the lessee to pay minimum rental payments to PVR in monthly or annual installments. PVR actively works with its lessees to develop efficient methods to exploit its coal reserves and to maximize production from its properties. PVR also earns revenues from providing fee-based coal preparation and transportation services to its lessees, which enhance their production levels and generate additional coal royalty revenues, and from industrial third party coal end-users by owning and operating coal handling facilities through its joint venture with Massey Energy Company. In addition, PVR earns revenues from oil and gas royalty interests it owns, from coal transportation, or wheelage, rights and from the sale of standing timber on its properties.

PVR s management continues to focus on acquisitions that increase and diversify its sources of cash flow. PVR increased its coal reserves by 162 million tons, or 29% from its year end coal reserves as of December 31,

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2004, by completing four coal reserve acquisitions in 2005, for an aggregate purchase price of approximately $101 million. These acquisitions included 94 million tons of coal reserves in the Illinois Basin, a new market area for PVR. As part of these acquisitions, PVR also acquired oil and natural gas well royalty interests and wheelage rights. In addition, on May 25, 2006, PVR acquired for $65 million the lease rights to approximately 69 million tons of coal reserves in West Virginia. For a more detailed discussion of PVR s recent acquisitions, see Management s Discussion and Analysis of Financial Condition and Results of Operations PVR s Recent Acquisitions and Investments.

Natural Gas Midstream Segment Overview

PVR owns and operates midstream assets that include approximately 3,573 miles of natural gas gathering pipelines and three natural gas processing facilities located in Oklahoma and the panhandle of Texas, which have 160 million cubic feet per day (or MMcfd) of total capacity located. PVR s midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. PVR also owns a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines. PVR acquired its natural gas midstream assets from Cantera Gas Resources, LLC in March 2005. PVR believes that this acquisition established a platform for future growth in the natural gas midstream sector and diversified its cash flows into another long-lived asset base. Since acquiring these assets, PVR has expanded its natural gas midstream business by adding 142 miles of new gathering lines.

For the twelve months ended September 30, 2006, inlet volumes at PVR s gas processing plants and gathering systems were 51 billion cubic feet (or Bcf), or approximately 141 MMcfd.

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

PVR s Strengths and Strategies

PVR s primary objective is to generate stable cash flows and increase its cash available for distribution to its unitholders. We believe that PVR is well-positioned to execute its business objective due to the following competitive strengths:

Its coal royalty structure helps generate stable and predictable cash flows and limit its exposure to declines in coal prices. PVR s coal leases provide either for royalty rates equal to the higher of a fixed minimum rate or a percentage of the gross sales price received by its lessees for the coal they produce from its reserves, or for a fixed royalty rate. This structure allows PVR s earnings and cash flow to be stable and predictable in periods of low commodity prices, while enabling it to benefit during periods of high commodity prices. Also, since PVR does not operate any mines, it does not directly bear any operational risks or production costs.

It leases its coal reserves to experienced lessees that have long-term relationships with major customers. PVR leases its reserves principally to lessees that have substantial experience as coal mine operators, established reputations in the industry and strong relationships with major electric utilities, independent power producers and other commercial and industrial customers.

A significant amount of its coal reserves are low sulfur coal. With Phase II of the Clean Air Act Amendments in effect, compliance and low sulfur coal have captured a growing share of U.S. coal demand, commanding higher prices than higher sulfur coal in the market place. As of December 31, 2005, approximately 25% of PVR s coal reserves met compliance standards for the Clean Air Act and approximately 48% of its coal reserves were low sulfur coal, including compliance coal. We believe that

PVR is well-positioned to capitalize on the continuing growth in demand for low sulfur coal to produce electricity.

Its assets are strategically located. PVR s coal reserves are located on or near the major coal hauling railroads and inland waterways that serve Central Appalachia and the Illinois Basin. PVR believes that the geographic location of its reserves gives its lessees a transportation cost advantage that improves their competitive position and its corresponding coal royalty revenues. PVR s midstream assets are located in the Mid-Continent and Rocky Mountain regions of the United States. The natural gas reserves in these regions are generally characterized as having moderately declining long-lived reserves, and the regions significant current drilling activity provides PVR with attractive opportunities to access newly-developed natural gas supplies. These regions have experienced increased levels of exploration, development and production activities as a result of recent high commodity prices, new discoveries and the implementation of new completion and secondary recovery techniques. In addition, many of PVR s midstream assets have available capacity. We believe that PVR s presence in these regions, together with the available capacity of its assets and limited competitive alternatives, provides PVR with a competitive advantage in capturing new supplies of natural gas.

It provides an integrated and comprehensive package of natural gas midstream services. PVR provides a broad range of midstream services to natural gas producers, including natural gas gathering, compression, dehydration, treating, processing and marketing and the fractionation of NGLs. We believe PVR s ability to provide all of these services gives it an advantage in competing for new supplies of natural gas, because it can provide all of the services producers, marketers and others require to connect their natural gas quickly and efficiently.

Its natural gas midstream hedging strategies help reduce its exposure to declines in natural gas and NGL prices. In order to manage PVR s exposure to price risks in the marketing of its natural gas and NGLs under its percentage-of-proceeds and keep-whole arrangements, and to reduce the effects of volatile natural gas and NGL prices, PVR periodically enters into natural gas and NGL price hedging arrangements with respect to a portion of its expected production. For the fourth quarter of 2006 and full year 2007, PVR has hedged approximately 65% and 30%, respectively, of its midstream commodity price exposure based on its current planned production.

PVR s existing assets and properties allow it to enhance cash flows through low-cost expansions and increased utilization. PVR utilizes its expertise to increase cash flows from existing coal reserves by identifying the need for and providing additional fee-based infrastructure services, including coal preparation and transportation services. In addition, PVR s natural gas midstream systems currently have excess capacity that allow for low-cost scalability through the addition of new volumes and enhanced utilization.

It is well-positioned to pursue acquisitions. PVR has a proven track record of successfully completing acquisitions that have increased its cash available for distributions. Since its initial public offering in October 2001, PVR has completed numerous acquisitions of coal reserves for an aggregate purchase price of approximately $356.7 million and two acquisitions of midstream assets for an aggregate purchase price of approximately $205.7 million. We believe that PVR s affiliation with Penn Virginia Corporation will provide it with a competitive advantage in pursuing acquisition opportunities, particularly opportunities involving the acquisition of multiple natural resource assets. Furthermore, PVR intends to use the proceeds from our purchase of its common units and Class B units as described in Use of Proceeds to repay approximately $107.5 million of borrowings outstanding under its revolving credit facility, which will increase PVR s borrowing capacity to approximately $170 million.

Its management team has a successful record of managing, growing and acquiring coal properties and natural gas and midstream assets. PVR has been involved in the coal land management business in Appalachia since 1882. In addition, PVR has a highly capable and experienced management team that is familiar with the areas in which its lessees mine coal, the mining environment, the midstream energy industry and trends in the coal and natural gas midstream industries. PVR s team has an active land

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management style and reviews numerous acquisition opportunities and organic growth projects on an ongoing basis.

PVR has successfully grown its businesses through organic growth projects and acquisitions of coal properties and natural gas midstream assets. Since its initial public offering in October 2001, PVR has completed numerous accretive acquisitions for an aggregate purchase price of approximately $562.4 million. PVR intends to continue to pursue the following business strategies:

Continue to grow coal reserve holdings through acquisitions and investments in its existing market areas, as well as strategically entering new markets. While PVR continues to build upon its core holdings in Appalachia, it also continues to monitor coal opportunities in other areas. For example, in 2005 PVR made an investment in Illinois Basin coal reserves because PVR views the Illinois Basin as a growth area, both because of its proximity to power plants and because PVR expects future environmental regulations will require scrubbing of not only higher sulfur Illinois Basin coal, but most coals, including lower sulfur coals from other basins. PVR expects to continue to diversify its coal reserve holdings into this and other domestic basins in the future.

Expand its coal services and infrastructure business on its properties. Coal infrastructure projects typically involve long-lived, fee-based assets that generally produce steady and predictable cash flows and, are therefore, attractive publicly traded limited partnerships. PVR owns a number of such infrastructure facilities and intends to continue to look for growth opportunities in this area of operations. For example, in 2005, PVR began constructing a new preparation and loading facility on property it acquired in 2005, which is expected to commence operation in late 2006.

Expand its joint venture with Massey Energy Company to generate fee based income and provide other business development opportunities for coal-related infrastructure projects. In addition to the fee-based coal-related infrastructure projects that involve end users of coal in several manufacturing applications, the joint venture purchased an interest in a business which manufactures coal quality analyzing equipment. In addition to providing future profits and cash flow, this business is expected to provide other development opportunities for coal-related infrastructure projects.

Expand its midstream operations through acquisitions of new gathering and processing related assets and by adding new production to its existing systems. The natural gas midstream sector is well-suited to PVR s publicly traded limited partnership structure and includes many potential acquisition opportunities. In addition, PVR seeks to expand its natural gas midstream segment organically by expanding its gathering systems to add new production to its existing systems. In 2005, PVR added approximately 27 miles of new gathering lines, allowing it to connect over 90 new wells to its systems. PVR s business development personnel are actively seeking new acquisition and expansion opportunities in the sector. For example, during 2005, PVR began marketing Penn Virginia Corporation s natural gas production in Texas and Louisiana, replacing a third party marketing company and allowing Penn Virginia Corporation to realize higher prices for its oil and natural gas sold in that region. PVR will continue to look for ways to take advantage of its natural relationship with Penn Virginia Corporation in mutually beneficial ways.

PVR s Operations

Coal Segment

As of December 31, 2005, PVR owned or controlled approximately 689 million tons of proven and probable coal reserves located on approximately 337,000 acres (including fee and leased acreage) in Kentucky, New Mexico, Virginia and West Virginia. PVR s coal reserves are in various surface and underground mine seams located on the following properties:

Central Appalachia Basin: properties located in Buchanan, Lee and Wise Counties, Virginia; Floyd, Harlan, Knott and Letcher Counties, Kentucky; and Boone, Fayette, Kanawha, Lincoln, Logan and Raleigh Counties, West Virginia;

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Northern Appalachia Basin: properties located in Barbour, Harrison, Lewis, Monongalia and Upshur Counties, West Virginia;

San Juan Basin: properties located in McKinley County, New Mexico; and

Illinois Basin: properties located in Henderson and Webster Counties, Kentucky.

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

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

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

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

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

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

PVR s lessees mine coal using both underground and surface methods. PVR s lessees currently operate 26 surface mines and 37 underground mines. Approximately 61% of the coal produced from PVR s properties in 2005 came from underground mines and 39% came from surface mines. Most of PVR s lessees use the continuous mining method in all of their underground mines located on PVR s 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, PVR s lessees use two continuous miners running at the same time, also known as a supersection, to improve productivity and reduce unit costs.

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

Surface mining methods used by PVR s lessees include auger and highwall mining to enhance production, improve reserve recovery and reduce unit costs. On PVR s San Juan Basin property, a combination of the

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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.

PVR s lessees customers are primarily utilities. Coal produced from PVR s properties is transported by rail, barge and truck, or a combination of these means of transportation. Coal from the Virginia portion of the Wise property and the Buchanan property is primarily shipped to electric utilities in the Southeast by the Norfolk Southern railroad. Coal from the Kentucky portion of the Wise property is primarily shipped to electric utilities in the Southeast by the CSX railroad. Coal from the Coal River and Spruce Laurel properties is shipped to steam and metallurgical customers by the CSX railroad, by barge along the Kanawha River and by truck or by a combination thereof. Coal from the northern Appalachia property is shipped by barge on the Monongahela River, by truck and by the CSX and Norfolk Southern railroads. Coal from the Illinois Basin property 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 PVR s properties contain and have access to numerous roads and state or interstate highways.

The following table sets forth production data and reserve information with respect to each of PVR s properties:

	Production						
	Nine Months Ended September 30,	Year Ended December 31,			Proven and Probable Reserves at December 31, 2005		
Property	2006	2005	2004	2003	Under-ground	Surface	Total
	(tons in millions)						
Central Appalachia	15.0	19.0	20.1	15.1	373.2	120.5	493.7
Northern Appalachia	3.9	5.0	5.6	5.1	37.4	2.2	39.6
Illinois Basin	1.9	1.4			78.5	14.3	92.8
San Juan Basin	3.7	4.8	5.5	6.3		63.0	63.0
Total	24.5	30.2	31.2	26.5	489.1	200.0	689.1

Of the approximately 689 million tons of proven and probable coal reserves to which PVR had rights as of December 31, 2005, it owned the mineral interests and the related surface rights to 389.4 million tons, or 56%, and it owned only the mineral interests to 219.9 million tons, or 32%. PVR leases the mineral rights to the remaining 79.8 million tons, or 12%, from unaffiliated third parties and, in turn, subleases these reserves to its lessees. For the coal reserves PVR leases from third parties, it pays royalties to the owner based on the amount of coal produced from the lease reserves. Additionally, in some instances, PVR purchases surface rights or otherwise compensates surface right owners for mining activities on their properties. In 2005, PVR s aggregated expenses to third-party surface and mineral owners were $4.2 million.

The following table sets forth the coal reserves PVR owns and leases with respect to each of PVR s coal properties as of December 31, 2005:

Property	Owned	Leased	Total

	(tons in millions)		
Central Appalachia	417.8	75.9	493.7
Northern Appalachia	39.6		39.6
Illinois Basin	92.8		92.8
San Juan Basin	59.1	3.9	63.0
Total	609.3	79.8	689.1

PVR s coal reserve estimates are prepared from geological data assembled and analyzed by PVR s general partner s geologists and engineers. These estimates are compiled using geological data taken from thousands of

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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.

PVR classifies 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 Clean Air Act. As of December 31, 2005, approximately 25% of PVR s reserves met compliance standards for the Clean Air Act and 48% were low sulfur. The following table sets forth PVR s estimate of the sulfur content and the typical clean coal quality of PVR s recoverable coal reserves at December 31, 2005:

		Sulfur Content						Typical Clean Coal Quality		
		Reserves as of December 31, 2005						Heat Content		
Property	**Type of Coal**	**Compliance (1)**	**Low Sulfur (2)**	**Medium Sulfur**	**High Sulfur**	**Sulfur Unclassified**	**Total**	**Btu per Pound (3)**	**Sulfur (%)**	**Ash (%)**
		(tons in millions)								
Central Appalachia	Steam/Metallurgical	175.6	298.2	127.5	32.8	35.2	493.7	12,863	1.05	7.07
Northern Appalachia	Steam/Metallurgical	0.0	0.0	0.0	39.6	0.0	39.6	12,900	2.58	8.80
Illinois Basin	Steam/Metallurgical	0.0	0.0	0.0	92.9	0.0	92.9	11,005	3.90	11.38
San Juan Basin	Steam	0.0	35.9	21.4	5.6	0.0	62.9	9,200	0.89	17.80
Total		175.6	334.1	148.9	170.9	35.2	689.1			

(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 the Clean Air Act 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 reserves PVR leases to mine operators by property:

	Proven and Probable Reserves As of December 31, 2005		
Property	**Controlled**	**Leased (Out)**	**Percentage Leased (Out)**
	(tons in millions)		
Central Appalachia	493.7	400.2	81%
Northern Appalachia	39.6	39.2	99%
Illinois Basin	92.9	43.1	46%
San Juan Basin	62.9	63.0	100%

Total	689.1	545.5	79%

PVR generates revenues from fees it charges to its lessees for the use of PVR s coal preparation and loading facilities. The facilities provide efficient methods to enhance lessee production levels and exploit PVR s reserves. Historically, the majority of these fees have been generated by PVR s unit train loadout facility on its central Appalachia property, which accommodates 108 car unit trains that can be loaded in approximately four hours. Some of PVR s lessees utilize the unit train loadout facility to reduce the delivery costs incurred by their customers. The coal service facility PVR purchased in November 2002 on its Coal River property in West Virginia began operations late in the third quarter of 2003. In the first quarter of 2004, PVR placed into service a newly constructed coal loadout facility for another lessee in West Virginia for $4.4 million. In September 2006, PVR completed constructing a new preparation and loading facility on property PVR acquired in 2005 in eastern Kentucky.

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The following table shows PVR s most important coal producing seams by property.

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

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The following table shows coal preparation and loading facilities located on or near PVR s coal properties that serve coal produced by PVR s lessees.

Area	Property	State	Facility
Central Appalachia	Wise	Virginia	Pigeon Creek Processing Plant and Loadout (NS Railroad)
			Steer Branch Preparation Plant and Loadout (NS Railroad)
			Critical Fork Stoker Plant and Loadout (NS Railroad)
			Cane Patch Preparation Plant and Loadout (NS Railroad)
			Cumberland River Coal Pardee Preparation Plant and Loadout (NS Railroad)
			Calvin Preparation Plant and Loadout (NS Railroad)
			Toms Creek Preparation Plant and Loadout (NS Railroad)
			Cave Branch Preparation Plant and Loadout (CSX Railroad)
			Pine Branch Preparation Plant and Loadout (NS Railroad)
			Paragon Rail Loadout(1) (NS Railroad)
			Andover Loadout (NS Railroad)
			Osaka Loadout (Idle) (NS Railroad)
			Holton Loadout (Idle) (NS Railroad)
			Nehemiah Preparation (Jig) Plant(1) (Truck)
			Derby Preparation (Jig) Plant(1) (Truck)
			Appalachian Coal Preparation (Jig) Plant(1) (Truck)
	Coal River, Fields Creek	West Virginia	Eagle Preparation Plant and Loadout (Kanawha Rail Corp. Railroad)
			Wet Branch (Panther) Preparation Plant and Loadout (CSX Railroad)
			Weatherby Preparation Plant (Truck)
			Winifrede Dock Barge Loading Facility(1) (Kanawha River) (CSX and Kanawha Railroads)
			Kanawha Rail Corp 6.5 mile Rail Spur
			Bull Creek Loadout(1) (CSX Railroad)
			Fork Creek Preparation Plant(1) and Rail Loadout(1) (CSX Railroad)
	Alloy	West Virginia	Alloy Preparation Plant (Truck)
	Spruce Laurel	West Virginia	Rock Lick Preparation Plant and Loadout (CSX Railroad)
			Wells Plant and Loadout (CSX Railroad)
			Independence Preparation Plant and Loadout (CSX Railroad)
			Spruce Laurel Loadout(1) (CSX Railroad)
	Toney Fork	West Virginia	Toney Fork Loadout (CSX Railroad)
	Wayland	Kentucky	Wayland Preparation Plant and Rail Loadout(1) (Under Construction) (CSX Railroad)
Northern Appalachia	Upshur	West Virginia	Marion Docks Barge Loadout (Monongahela River)
	Federal	West Virginia	Federal Preparation Plant and Loadout (NS Railroad)
Illinois Basin	Green River	Kentucky	Patriot Preparation Plant and Barge Loadout (Green River)
			Green River Preparation Plant(1) and Barge Loadout(1) (Idle) (Green River)
New Mexico	Lee Ranch	New Mexico	Lee Ranch Loadout (Lee Ranch owned rail spur, BNSF Railroad)

(1) Facilities owned by PVR.

Natural Gas Midstream System

PVR s midstream operations currently include three natural gas gathering and processing systems and one standalone natural gas gathering system, including: (i) the Beaver/Perryton gathering and processing facilities in the Texas/Oklahoma panhandle area, (ii) the Crescent gathering and processing facilities in central Oklahoma, (iii) the Hamlin gathering and processing facilities in west-central Texas, and (iv) the Arkoma gathering system in eastern Oklahoma. These systems include approximately 3,450 miles of natural gas gathering pipelines and three natural gas processing facilities, which have 160 MMcfd of total capacity. PVR s natural gas midstream business generates revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. PVR owns, leases or has rights-of-way to the properties where the majority of its midstream facilities are located.

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

				Ten Months Ended December 31, 2005 (3)		Nine Months Ended September 30, 2006	
Asset	**Type**	**Approximate Length (Miles)**	**Current Processing Capacity (Mmcfd) (1)**	**Average Plant Throughput (Mmcfd) (1)**	**Utilization of Processing Capacity (%)**	**Average Plant Throughput (Mmcfd)**	**Utilization of Processing Capacity (%)**
Beaver/Perryton System	Gathering pipelines and processing facility	1,180	100	87.0	87.0%	97.4	97.4%
Crescent System	Gathering pipelines and processing facility	1,675	40	18.5	66.1%	18.5	66.1%
Hamlin System	Gathering pipelines and processing facility	517	20	6.6	33.0%	6.8	68.0%
Arkoma System	Gathering pipelines	78		14.9(2)		14.9(2)	
North Canadian System	Gathering pipelines	115				6.8(2)	
Total		3,565	160	127.0		144.4	

(1) Many capacity values are based on current operating configurations and could be increased through additional compression, increased delivery meter capacity or other facility upgrades.
(2) Gathering only volumes.
(3) Includes the results of operations since March 3, 2005, the closing date of PVR s acquisition of its natural gas midstream business.

The Beaver/Perryton System

General. The Beaver/Perryton System is a natural gas gathering system stretching over ten counties in the Anadarko Basin of the panhandle of Texas and Oklahoma. The system consists of approximately 1,180 miles of natural gas gathering pipelines, ranging in size from two to 16 inches in diameter, and the Beaver natural gas processing plant. Included in the system is an 11-mile, 10-inch diameter, FERC-jurisdictional residue line. Also included is the non-jurisdictional 115-mile pipeline that was recently acquired from Transwestern Pipeline Company and serves to connect a number of PVR s gathering systems directly to the Beaver plant.

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

The Beaver natural gas processing plant has 100 MMcfd of inlet gas capacity. The plant is capable of relatively high ethane recovery, and is instrumented to allow for unattended operations 16 hours per day.

Natural Gas Supply. The supply in the Beaver/Perryton System comes from approximately 165 producers pursuant to 313 contracts. The average gas quality on the Beaver/Perryton System for 2005 was 3.6 gallons of NGLs per delivered Mcf.

Markets for Sale of Natural Gas and NGLs. The residue gas from the Beaver plant can be delivered into 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 Koch Hydrocarbon s pipeline system for transportation to and fractionation at Koch s Conway fractionator.

The 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 1,675 miles of natural gas gathering pipelines,

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ranging in size from two to 10 inches in diameter, and the Crescent 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 252 producers pursuant to 406 contracts. The average gas quality on the Crescent System for 2005 was 5.5 gallons of NGLs per delivered Mcf.

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

The Hamlin System

General. The Hamlin System is a natural gas gathering system stretching over eight counties in West Central Texas. The system consists of approximately 517 miles of natural gas gathering pipelines, ranging in size from two to 12 inches in diameter and with current capacity of approximately 20 MMcfd, and the Hamlin natural gas processing plant located in Fisher County, Texas. Eight compressor stations are operating across the system.

Natural Gas Supply. 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 107 producers pursuant to 139 contracts. The average gas quality on the Hamlin System for 2005 was 9.8 gallons of NGLs per delivered Mcf.

Markets for Sale of Natural Gas and NGLs. The Hamlin System delivers the residue gas from the Hamlin System into the Enbridge or Atmos pipelines. NGLs from the Hamlin plant are tendered into a line operated by TEPPCO.

The Arkoma System

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

Natural Gas Supply. The supply on the Arkoma System comes from approximately 27 producers pursuant to 37 contracts.

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

Natural Gas Marketing

In connection with the 2005 acquisition of PVR s midstream business, PVR also acquired a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline

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systems such as Enogex and ONEOK and at market hubs accessed by various interstate pipelines. The largest third-party customer is Chesapeake Energy Corp. with volumes contracted through 2007. Revenue from this business does not generate qualifying income for a master limited partnership, but PVR does not expect it to have an impact on PVR s tax status, as it does not represent a significant percentage of PVR s operating income. For the year ended December 31, 2005, this business generated approximately $1.9 million in net revenue.

PVR s Contracts

Coal Segment

PVR earns most of its coal royalty revenues under long-term leases that generally require its lessees to make royalty payments to it based on the higher of a percentage of the gross sales price or a fixed price per ton of coal they sell. The balance of its coal royalty revenues are earned under two long-term leases with affiliates of Peabody Energy Corporation (NYSE: BTU), or Peabody, that require the lessees to make royalty payments to PVR based on fixed royalty rates which escalate annually. A typical lease either expires upon exhaustion of the leased coal reserves, which is the case with the two Peabody leases, or has a five to ten-year base term, with the lessee having an option to extend the lease for at least five years after the expiration of the base term.

Substantially all of PVR s leases require the lessee to pay minimum rental payments in monthly or annual installments, even if no mining activities are ongoing. These minimum rentals are recoupable, usually over a period from one to three years from the time of payment, against the production royalties owed to PVR once coal production commences.

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

Natural Gas Midstream Segment

PVR s natural gas midstream segment is engaged in providing gas processing, gathering and other related natural gas services. PVR s 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, 2005, PVR s natural gas midstream business generated a majority of its gross margin from two types of contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs: (i) percentage-of-proceeds and (ii) keep-whole arrangements. In 2005, approximately 55% of the volumes were processed under gas purchase / keep-whole contracts, 32% were processed under percentage of proceeds contracts, and 13% were processed under fee-based gathering contracts. A majority of the gas purchase/keep-whole and percentage of proceeds contracts include fee-based components such as gathering and compression charges. There is also a processing fee floor included in many of the gas purchase/keep-whole contracts that ensures a minimum processing margin should the actual margins fall below the floor.

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

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

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

In many cases, PVR provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of its 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.

Virtually all of the natural gas gathered on the Crescent System and the Hamlin System is contracted under percentage-of-proceeds arrangements. The natural gas gathered on Beaver System is contracted primarily under either percentage-of proceeds or gas purchase/keep-whole arrangements.

PVR is also engaged in natural gas marketing by aggregating third-party volumes and selling those volumes into interstate and intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

PVR s Competition

Coal Segment

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

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Natural Gas Midstream Segment

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

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

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

Government Regulation and Environmental Matters Related to PVR s Operations

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

Coal Segment

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

While it is not possible to quantify the costs of compliance by PVR s lessees with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. The lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. PVR does not accrue for such costs because its lessees are contractually liable for all costs relating to their mining operations, including the costs of reclamation and mine closure. However, PVR does require some smaller lessees to deposit into escrow certain funds for reclamation and mine closure costs or post performance bonds for these costs. Although 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.

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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 its lessees. The possibility exists that new legislation or regulations may be adopted which have a significant impact on the mining operations of its lessees or their customers ability to use coal and may require PVR, its lessees or their customers to change operations significantly or incur substantial costs.

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

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

The EPA has promulgated rules, referred to as the NOx SIP Call, that require coal-fired power plants and other large stationary sources in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule (or CAIR), which will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C beginning in 2009 and 2010, respectively. CAIR requires these states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered cap-and-trade program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state.

In March 2005, the EPA finalized the Clean Air Mercury Rule (or CAMR), which establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. While currently the subject of extensive controversy and litigation, if fully implemented, CAMR would permit states to implement their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances.

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. For example, in December 2004, the EPA designated specific areas in the United States as in non-attainment with the new national ambient air quality standard for fine particulate matter. In November 2005, the EPA published proposed rules addressing how states would implement plans to bring applicable non-attainment regions into compliance with the new air quality standard. Under the EPA s proposed rulemaking, states would have until April 2008 to submit their implementation plans to the EPA for approval. Because coal mining operations and coal-fired electric generating facilities emit particulate matter, PVR s lessees mining operations and their customers could be affected when the new standards are implemented by the applicable states.

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In June 2005, the EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. As part of the new rules, affected states must 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 Clean Air Act. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for PVR s coal could be affected, which could have an adverse effect on its coal royalty 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 five percent 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. As the Kyoto Protocol becomes effective, there will likely be increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. The United States Congress has considered bills in the past that would regulate domestic carbon dioxide emissions, but such bills have not yet received sufficient Congressional support for passage into law. Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. For example, in December 2005, seven northeastern states agreed to implement a regional cap-and-trade program to stabilize carbon dioxide emissions from regional power plants beginning in 2009.

It is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact PVR s lessees coal sales, and thereby have an adverse affect on its coal royalty revenues.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977 (or SMCRA) and similar state statutes impose 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. Regulatory authorities may attempt to assign the liabilities of PVR s coal lessees to PVR if any of these lessees are not financially capable of fulfilling those obligations. In conjunction with mining the property, PVR s coal lessees are contractually obligated under the terms of their leases to comply with all state and local laws, including SMCRA, with obligations including the reclamation and restoration of the mined areas by grading, shaping and reseeding the soil. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan.

Hazardous Materials and Waste. The Federal Comprehensive Environmental Response, Compensation and Liability Act (or CERCLA or the Superfund law), and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed

to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

Some products used by coal companies in operations generate waste containing hazardous substances. PVR could become liable under federal and state Superfund and waste management statutes if PVR s 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 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.

Water Discharges. PVR s lessees operations can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States or state waters. The unpermitted discharge of pollutants such as from spill or leak incidents is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of fill material and certain other activities in wetlands unless authorized by an appropriately issued permit.

PVR s lessees mining operations are strictly regulated by the Clean Water Act, particularly with respect to the discharge of overburden and fill material into jurisdictional waters, including wetlands. Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers to streamline the process for obtaining permits under Section 404 of the Clean Water Act. While the decision was vacated by the Fourth Circuit Court of Appeals in November 2005, a similar lawsuit filed in federal district court in Kentucky seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. In the event that such lawsuits prove to be successful in adjoining jurisdictions, PVR s lessees may be required to apply for individual discharge permits pursuant to Section 404 of the Clean Water Act in areas where they would have otherwise utilized Nationwide Permit 21. Such a change could result in delays in PVR s lessees obtaining the required mining permits to conduct their operations, which could in turn have an adverse effect on its coal royalty revenues. Moreover, such individual permits are also subject to challenge. Alex Energy, Inc., a PVR lessee operating the Republic No. 2 Mine in Kanawha County, West Virginia, is currently a defendant in *Ohio Valley Environmental Coalition vs. U.S. Army Corps of Engineers*, a lawsuit in the Southern District of West Virginia in which environmental groups challenged the issuance of individual valley fill permits to multiple coal operators in the state. On June 13, 2006, the Corps of Engineers suspended the valley fill permits at issue in the case, including the permit under which our lessee operates. The court has since stayed all proceedings pending further action by the Corps on these permits. Although portions of the Republic No. 2 Mine continue to operate under separate authorizations, delays in securing additional permit authorization for the areas affected by the aforementioned permit withdrawal could have an adverse effect on PVR s coal royalty revenues.

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

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

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

Recent mining accidents in West Virginia and Kentucky have received national attention and instigated responses at the state and national level that have resulted 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 new mining safety legislation that mandates similar 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. Earlier, the federal Mine Safety Health Administration announced the promulgation of new emergency rules on mine safety that took effect immediately upon their publication in the *Federal Register* on March 9, 2006. These rules address mine safety equipment, training, and emergency reporting requirements. Implementing and complying with these new laws and regulations could adversely affect PVR s lessees coal production and could therefore have an adverse affect on PVR s coal royalty revenues and its ability to make distributions to us.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, PVR s 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.

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

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

Natural Gas Midstream Segment

General Regulation. PVR s natural gas gathering facilities generally are exempt from the FERC s jurisdiction under the NGA, but FERC regulation nevertheless could significantly affect PVR s gathering business and the market for its services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which its 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, natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that 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 operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

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

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

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

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

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

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

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

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

Water Discharges. PVR s midstream operations are subject to the Clean Water Act. See Coal Segment Water Discharges. Any unpermitted release of pollutants, including NGLs or condensates, from PVR s systems or facilities could result in fines or penalties as well as significant remedial obligations.

OSHA. PVR s midstream operations are subject to OSHA. See Coal Segment OSHA.

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Title to Properties

PVR believes that it has satisfactory title to all of its properties and the associated coal reserves in accordance with standards generally accepted in the coal and natural gas midstream industries.

Facilities

PVR s general partner provides all of PVR s office space, except for a field office that PVR owns near Charleston, West Virginia.

Employees

PVR does not have any employees. To carry out PVR s operations, its general partner and the general partner s affiliates employed 111 employees who directly supported PVR s operations at December 31, 2005. PVR s general partner considers current employee relations to be favorable.

Legal Proceedings

Although PVR may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of business, PVR is not currently a party to any material legal proceedings. In addition, it is not aware of any material legal or governmental proceedings against it, or contemplated to be brought against it, under the various environmental protection statutes to which it is subject. See Government Regulation and Environmental Matters Related to PVR s Operations for a more detailed discussion of our material environmental obligations.

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MANAGEMENT

Penn Virginia GP Holdings, L.P.

Directors and Executive Officers of PVG GP, LLC

The following table sets forth certain information with respect to the executive officers and members of the board of directors of our general partner, PVG GP, LLC. Executive officers and directors of our general partner will serve until their successors are duly appointed or elected.

Name	Age	Position with Our General Partner
A. James Dearlove	59	Chairman of the Board of Directors and President and Chief Executive Officer
Robert Garrett	69	Director
Robert J. Hall	61	Director
Frank A. Pici	50	Director and Vice President and Chief Financial Officer
John C. van Roden, Jr.	57	Director
Nancy M. Snyder	53	Director and Vice President, General Counsel and Assistant Secretary
Jonathan B. Weller	60	Director

A. James Dearlove has served as our general partner s Chairman of the Board of Directors, President and Chief Executive Officer since September 6, 2006 and as Chairman of the Board of Directors and Chief Executive Officer of PVR s general partner since December 2002 and July 2001. Mr. Dearlove has also served in various capacities with Penn Virginia Corporation 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 Corporation and as a director of the National Council of Coal Lessors.

Robert Garrett has served as our general partner s director since September 7, 2006 and as non-executive Chairman of the Board and a director of Penn Virginia Corporation since May 2000 and May 1997, respectively. Mr. Garrett was also the founder, and has served as Managing Director of, AdMedia Partners, Inc. (AdMedia), an investment banking firm serving media, advertising and marketing services businesses, since 2005. From 1990 to 2005, Mr. Garrett served as President of AdMedia. From 1986 to date, Mr. Garrett has also served as President of Robert Garrett & Sons, Inc., a private investing and financial advisory company.

Robert J. Hall has served as our general partner s director since September 22, 2006. Since June 2004, Mr. Hall has been providing consulting services in newspaper industry acquisitions. From January 2004 to May 2004, Mr. Hall was retired. From 1990 to December 2003, Mr. Hall served as Publisher and Chairman of Philadelphia Newspapers, Inc., which publishes the Philadelphia Inquirer and the Philadelphia Daily News. From 1985 to 1989, Mr. Hall served as General Manager of Detroit Free Press, and from 1989 to 1990, he served as Chairman of Detroit Free Press.

Frank A. Pici has served as our general partner s Director, Vice President and Chief Financial Officer since September 6, 2006 and as Vice President and Chief Financial Officer of PVR s general partner since September 2001 and as a director since October 2002. Mr. Pici has also served as Executive Vice President and Chief Financial Officer of Penn Virginia Corporation since September 2001. From 1996 to September 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 Company.

John C. van Roden, Jr. has served as our general partner s director since September 22, 2006. From April 2003 to date, Mr. van Roden has served as Executive Vice President of Glatfelter, a global manufacturer of specialty papers and engineered products, and from April 2003 to June 2006, he served as Chief Financial Officer of Glatfelter. From 1998 to April 2003, Mr. van Roden served as Senior Vice President and Chief Financial Officer of Conectiv, a company engaged in the transmission and distribution of electricity and the distribution of natural gas to customers in the Mid-Atlantic region. From 1982 to 1998, Mr. van Roden served as Senior Vice President and Chief Financial Officer of Lukens, Inc., a producer of specialty steel.

Nancy M. Snyder has served as our general partner s Director and Vice President, General Counsel and Assistant Secretary since September 6, 2006 and as Vice President and General Counsel and as a director of PVR s general partner since July 2001. Ms. Snyder has also served in various capacities with Penn Virginia Corporation since 1997, including as Executive Vice President since May 2006, as Senior Vice President since February 2003, as Vice President from December 2000 to February 2003 and as General Counsel and Corporate Secretary since 1997.

Jonathan B. Weller has served as our general partner s director since September 22, 2006. From April 2006 to September 2006, Mr. Weller was retired. From 1994 to April 2006, Mr. Weller has served in various capacities with Pennsylvania Real Estate Investment Trust, an owner, operator and developer of shopping centers in the eastern United States, including as Vice Chairman and Trustee since June 2004 to April 2006, as President and Chief Operating Officer from 1994 to June 2004 and as Trustee from 1994 to March 2006.

Our Board Committees

The NYSE does not require a listed limited partnership like us to have a majority of independent directors or to establish a nominating and governance or a compensation committee.

Audit Committee

Our general partner s board of directors has established an audit committee. The members of the audit committee meet the independence standards established by the NYSE.

Conflicts Committee

Our general partner s board of directors has established a conflicts committee. The conflicts committee consists of three members and is charged with reviewing specific matters that our general partner s board of directors believes may involve conflicts of interest. The conflicts committee may determine if the resolution of any conflict of interest submitted to it is fair and reasonable to us. In addition to satisfying certain other requirements, the members of the conflicts committee meet the NYSE independence standards for service on an audit committee of a board of directors. Any matters approved by the conflicts committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our unitholders and not a breach by us of any duties we may owe to our unitholders.

Our general partner may, but is not required to, seek approval from the conflicts committee of a resolution of a conflict of interest with our general partner or affiliates. If our general partner seeks approval from the conflicts committee, the conflicts committee will determine if the resolution of a conflict of interest with our general partner or its affiliates is fair and reasonable to us. Any matters approved by the conflicts committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. If a matter is submitted to the conflicts committee and the conflicts committee does not approve the matter, we will not proceed with the matter unless and until the matter has been modified in such a manner that the conflicts committee determines is fair and reasonable to us. The resolution of conflicts may not always be in our best interest or that of our unitholders. For a more detailed description of the conflicts of interest involving us and the resolution of these conflicts, please read Conflicts of Interest and Fiduciary Duties Conflicts of Interest.

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Compensation and Benefits Committee

Our general partner s board of directors has established a compensation and benefits committee. Its responsibilities include assisting the compensation and benefits committee of Penn Virginia Corporation when the Penn Virginia Corporation committee makes compensation decisions for the officers of our general partner, all of whom also serve as officers of Penn Virginia Corporation, as well as administering any incentive plans put in place by our general partner.