Penn Virginia GP Holdings, L.P.
Form 425
October 28, 2010

Filed by Penn Virginia GP Holdings, L.P. pursuant to Rule 425 under the

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Subject Company: Penn Virginia GP Holdings, L.P.

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Penn Virginia Resource Partners, L.P
American Association of
Individual Investors
Philadelphia Chapter
10/26/2010
NYSE: PVR
www.pvresource.com

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Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are "forward-looking" statements within the me
of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amende
Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those express
implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the fo
the volatility of commodity prices for natural gas, NGLs and coal; our ability to access external sources of capital; any impairn
write-downs of our assets; the relationship between natural gas, NGL and coal prices; the projected demand for and supply of n

gas, NGLs and coal; competition among producers in the coal industry generally and among natural gas midstream companies; extent to which the amount and quality of actual production of our coal differs from estimated recoverable coal reserves; our ab generate sufficient cash from our businesses to maintain and pay the quarterly distribution to our general partner and our unitho the experience and financial condition of our coal lessees and natural gas midstream customers, including our lessees ability t satisfy their royalty, environmental, reclamation and other obligations to us and others; operating risks, including unanticipated geological problems, incidental to our coal and natural resource management or natural gas midstream businesses; our ability t acquire new coal reserves or natural gas midstream assets and new sources of natural gas supply and connections to third-party pipelines on satisfactory terms; our ability to retain existing or acquire new natural gas midstream customers and coal lessees; t ability of our lessees to produce sufficient quantities of coal on an economic basis from our reserves and obtain favorable contr for such production; the occurrence of unusual weather or operating conditions including force majeure events; delays in antici start-up dates of our lessees mining operations and related coal infrastructure projects and new processing plants in our natura midstream business; environmental risks affecting the mining of coal reserves or the production, gathering and processing of n gas; the timing of receipt of necessary governmental permits by us or our lessees; hedging results; accidents; changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, includin respect to emissions levels applicable to coal-burning power generators; uncertainties relating to the outcome of current and fu litigation regarding mine permitting; risks and uncertainties relating to general domestic and international economic (including inflation, interest rates and financial and credit markets) and political conditions (including the impact of potential terrorist atta and other risks set forth in our Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with th Securities and Exchange Commission, including our Annual Report on Form 10-K for the year ended December 31, 2009. Ma the factors that will determine our future results are beyond the ability of management to control or predict. Readers should no undue reliance on forward-looking statements, which reflect management s views only as of the date hereof. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a r of new information, future events or otherwise.

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Diversified, Relatively Low-Risk Asset Base
Strategically Located Coal Reserves and Midstream Assets
Stable and Predictable Coal Royalty Business
Solid Balance Sheet and Attractive Yield
Stable Cash Flows and Distribution Coverage
Well
Positioned

to
Capitalize
on
Partnership
Momentum
&
Industry
Trends
Hedged Midstream Business with Growing Fee-Based Volumes
Key Investment Highlights

4
Current Structure
Penn Virginia
Resource Partners,
L.P.
(NYSE: PVR)
Public
Unitholders

32.7 MM
Common Units
60.4% LP interest
Penn Virginia
GP Holdings, L.P.
(NYSE: PVG)
Public
Unitholders
39.1 MM
Common Units
100% LP interest
Penn
Virginia
Resource
GP, LLC
100% ownership
2% GP Interest
and Incentive
Distribution Rights
37.6% LP interest
19.6 MM PVR Common Units
Notes:
1)
Chart displays simplified organizational structure
2)
Units outstanding and ownership interests are rounded
approximations
Penn Virginia
Operating Co., LLC
and its subsidiaries

5
Coal royalty
business,
not
coal
mining
Managed coal properties since 1882
Controls 829 MM tons of high quality coal

reserves (24 year R/P ratio)
Long-term leases with experienced operators
Ancillary businesses include coal services,
timber and gas royalties
Coal & Natural Resource Management
~ 2/3 of 2009 Adjusted EBITDA
(1)
Natural Gas Midstream
~ 1/3 of 2009 Adjusted EBITDA
(1)
$185 million of 2009 Adjusted EBITDA
(1)
Traditional gathering and processing business
Assets are located in attractive natural gas
basins with long-lived reserves

4,118 miles of pipelines

6 processing facilities

400 MMcfd of capacity
Average throughput volume 332 MMcfd in
2009
(1)
Adjusted EBITDA is a non-GAAP financial measure. See Appendix for a reconciliation of Adjusted EBITDA to net income ar
Overview

6
Coal & Natural Resource Management
San Juan
Basin
Northern
Appalachia
Illinois
Basin

Central
Appalachia
Coal reserves located in major supply basins
Access to major coal hauling railroads and inland waterways
Close proximity to power generation facilities
Gathering systems located in major gas basins
Reserves in Oklahoma, North Texas and East Texas are moderately declining and long-lived
Significant growth potential from Marcellus Shale
Crossroads
Arkoma
Panhandle
North Texas
Thunder Creek
Hamlin
Natural Gas Midstream
Marcellus
Crescent
Strategically Located Assets

Coal and Natural
Resource Management
7

8
~ 2/3 of 2009 Adjusted EBITDA
(1)
(1)
Adjusted EBITDA is a non-GAAP financial measure. See Appendix for a reconciliation of Adjusted EBITDA to net income ar
(2)
Does not include June 2010 acquisition of 10 millions tons of Pittsburgh Seam reserves. With that acquisition, the N. Appalac
Coal & Natural Resource Management

33.0
603.9
18.3
Central
Appalachia
5.0
37.4
7.5
San Juan
Basin
34.9
163.9
4.7
Illinois Basin
6.2
23.4
3.8
Northern
Appalachia
(2)
R/P
Ratio
(years)
Proven /
Probable
Reserves
(MM tons)
2009 Lease
Production
(MM tons)
Region
24.2 years
R/P Ratio:
828.6 MM tons
Proved / Probable Reserves:
34.3 MM tons
2009 Lease Production
Coal Production & Reserves

9
Coal
Attractive Long Term Fundamentals
EIA
(1)
forecasts that coal:
usage will continue to increase for next
25 years

will continue to be the dominant fuel for
electric power generation in the U.S.
will retain its cost advantage as the
cheapest energy source
(1)
Annual Energy Outlook 2010 (March 2010), Energy Information Administration (EIA)
Coal
Liquid Fuels
Natural Gas
Other
0
20
40
60
80
100
120
140
U.S. Energy Supply Composition By Primary Source
Fuel Oil
Natural Gas
Steam Coal
0
5
10
15
20
25
Coal
Petroleum
Natural Gas
Nuclear
Other
0
1000
2000
3000
4000
5000
6000
Energy Prices
(2)
U.S. Electrical Generation By Fuel Type
(2)
Prices paid for energy by Electric Generation Sector as reported by EIA

10
Coal Royalty vs. Coal Operator
Coal royalty
not a coal mining operation
Historical Coal Prices vs. Coal Royalty Revenue
Majority of our royalty payments (82%) are based on the higher of a percentage of the gross sales price or a fixed price per ton

Our lessees generally sell their coal under long-term fixed-price contracts (1
5 years),
which provides cash flow stability
Contracts with our lessees are long-term, with an average life of 10
15 years
No direct exposure to mine operating costs and risks or reclamation costs
Minimal maintenance capital expenditure requirements
Coal Royalty Business -
Stable and Predictable
High
Low
Reclamation Exposure
High
Low
Social Costs
(e.g. benefits, black lung)
High
Medium
Reinvestment Requirements
Variable
High
Cash Flow Stability
Variable
High
Operating Margins
Coal Operator
Coal Royalty
Characteristic
0
20
40
60
80
100
120
140
0
5
10
15
20
25
30
35
40
Quarterly Coal Royalty Revenue
Central Appalacia
Illinois Basin

Consists of a combination of surface and underground mines located in KY, VA and WV
Lessees customers are primarily electric utilities
Coal is higher quality, lower sulfur
Proximity to East Coast ports make these mines an ideal source of exports
Central Appalachia (73% of Reserves)

Illinois Basin (20% of Reserves)
Comprised of properties in southern Illinois and western Kentucky
Acquired 169 MM tons of reserves in the Illinois Basin beginning in 2005
The installation of scrubbers by Eastern and Midwestern utilities has increased demand for the high sulfur coal in the Illinois Basin
Primary Coal Basins
11

Northern Appalachia (3% of Reserves)
San Juan Basin (4% of Reserves)
Northern Appalachia holdings consist of the Federal and Upshur properties
Reserves are 100% owned and 98% have been leased to operators
Our Lee Ranch property is located in the San Juan Basin of northwestern New Mexico and

contains only surface coal mines
Increased production from 2006 to 2007,
whereas statewide coal production dropped
Other Coal Basins
12

13
Changes
in
Coal
Reserves:
2002

2009

Coal Production
Reserves
by
Type

2009
Net
Royalties
by
Region

2009
Reserves
by
Region

2009
Coal
Operations
492.8
571.3
(235.5)
0
200
400
600
800
1000
Reserves
12/31/01
Production
2002-2009
Acquired
2003-2009
828.6
0
5
10
15
20
25
30
35
40
2004
2005
2006
2007
2008
2009

Central Appalachia
San Jaun Basin
Illinois Basin
Northern Appalachia
Central
Appalachia
69%
San Juan
Basin
14%
Illinois
Basin
11%
Northern
Appalachia 6%
Central
Appalachia
73%
San Juan
Basin
4%
Illinois
Basin
20%
Northern
Appalachia 3%
Steam
89%
Metallurgical
11%

Fees charged to lessees for
use of coal preparation and
loading facilities
JV formed in July 2004

Fee-based revenues

Predictable cash flows

Services
5% of Coal & NRM Net Revenue
(1)
Approximately 243,000 acres
of forestland in Kentucky,
Virginia and West Virginia

Premium quality hardwood
primarily used for furniture
Timber
4% of Coal & NRM Net Revenue
(1)
In October 2007, we
purchased oil and gas
royalties located on 165,000
acres in eastern Kentucky
and southwestern Virginia

Almost all of our oil and
gas royalty interests are
associated with leases of
these properties
Oil & Gas Royalties
2% of Coal & NRM Net Revenue
(1)
Services, Timber & Oil & Gas Royalties
14
Represents 2009 Coal & NRM revenue less Coal Royalty expenses
(1)

Natural Gas
Midstream
15

16
~ 1/3 of 2009 Adjusted EBITDA
(1)
(1)
Adjusted EBITDA is a non-GAAP financial measure. See Appendix for a reconciliation of Adjusted EBITDA to net income ar
Natural Gas Midstream Overview
47
80

8
Crossroads
8
20
AMIs
with Range Resources
and a private E&P company
Marcellus
18
N/A
134
North
Texas
13
N/A
78
Arkoma
224
260
1,681
Panhandle
516
Hamlin
22
40
1,701
Crescent
375
N/A
588
Thunder
Creek
(25% JV)
2009
Volume
(MMcfd)
Processing
Capacity
(MMcfd)
Gathering
Pipeline
(Miles)
System
332 MMcfd
2009 Avg. System Throughput Vol:
400 MMcfd
Natural Gas Processing Capacity:
4,118 Miles
Gathering Pipeline:
Natural Gas Midstream Systems

17
Significant organic fee-based growth potential from Crossroads, Thunder Creek and Marcellus project (initial start-up in late 2010 / early 2011)
Target hedging 50-60% of remaining commodity-sensitive volumes over 2 years

Currently, 60% of 2010 and 58% of 2011 price-sensitive volumes are hedged
Additionally, many gas purchase / keep-whole contracts contain a processing fee floor
Volumes by Contract

2004
Volumes by Contract
2009
Since entering the midstream business, we have focused on reducing commodity price risk:

Acquiring fee-based businesses (North Texas and Thunder Creek)

Pursuing green field projects backed by fee-based contracts (Crossroads and Marcellus)

Converting a portion of existing keep-whole contracts to fee-based or POP
Hedged Midstream Business with
Growing Fee-Based Volumes
Fee-
Based
14%
Keep-
Whole
52%
Percent-of-
Proceeds
34%
Fee-Based
19%
Keep-
Whole
28%
Percent-of-
Proceeds
53%

18
Gas Rig Count vs. Natural Gas Production
Lower 48 State On-Shore Gas Production
Oil-to-Natural Gas Price Ratio
Source: Energy Information Administration, Baker Hughes, and Bloomberg
Our assets are well positioned to benefit from
increasing activity in emerging resource plays:

Granite Wash

Marcellus Shale

Haynesville Shale / Horizontal Cotton Valley
Attractive processing economics are expected to persist
Well Positioned Asset Base
0
200
400
600
800
1000
1200
1400
1600
1800
50
52
54
56
58
60
62
64
66
Rig Count
Production
0
2
4
6
8
10
12
14
16
18
20
Shale gas drives future production growth
0.0x
5.0x
10.0x
15.0x
20.0x
25.0x
1990
1995

2000
2005
2010
2015
2020
2025
2030
2035
Conventional
Shale Gas
Coalbed
Methane
Oil Associated

19
Gathering system in the Anadarko Basin of
Texas and Oklahoma
Comprised of a number of major gathering
systems and compressor stations

Beaver / Spearman plants
200 MMcfd of

inlet capacity

Sweetwater plant
Acquired in July
2009,
60 MMcfd of inlet capacity
Approximately 203 producers pursuant to
332 contracts
Positioned to capitalize on the development
of the Granite Wash
Overview
Operating Statistics
Processing Plants
3
Processing Capacity (MMcfd)
260
Gathering System Length (miles)
1,681
Panhandle System

20
Crossroads
Gathering system in Oklahoma s
Sooner Trend
Consists of 1,701 miles of pipeline
and 15 related compressor stations

Crescent

processing
plant

NGL
recovery plant with capacity of
40 MMcfd
Wells are generally low-volume and
long-lived with large NGL quantities
Crescent
Thunder Creek Gas Services
Hamlin
Arkoma
North Texas
Gathering system stretching over
West Central Texas with the Hamlin
processing plant located in Fisher
County, Texas
Consists of 500+ miles of pipeline
and 8 related compressor stations

Hamlin plant
20 MMcfd capacity
Consists of three separate stand-
alone gathering systems in
southeastern Oklahoma s Arkoma
Basin

Two systems are 100% owned,
third system is 49% owned

Average 2009 throughput volume
of 13 MMcfd
Purchased 25% JV interest in
Thunder Creek from Kinder Morgan
Energy Partners (April 08) in
Wyoming s Powder River Basin

Devon Energy owns the other
75% interest
100% fee-based model
Average 2009 throughput volume of
375 MMcfd
Located in the southeast portion of
Harrison County, Texas
Anchored by a long-term
commitment under a fee-based
arrangement
80 MMcfd of inlet capacity
Centered around 5 major producers
Positioned for growth from

Haynesville Shale
Acquired gas gathering and
transportation assets in the Barnett
Shale play in the Fort Worth Basin

134 miles of gathering pipeline

Approximately 240,000 acres
100% fee-based revenues

Potential to increase revenues
through addition of processing,
treating and other services
Natural Gas Midstream
Other Systems

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AMI with Range Resources in Lycoming, Bradford and Tioga Counties, PA

PVR to provide gathering, compression and related services

Range to initially dedicate over 75,000 acres with ongoing active lease acquisition program within the Area of Mutual Interest (AMI)

Gathering system will have over 700 MMcfd of throughput capacity
Total capital investment:

Expect $170
$200 million
between 2010 and 2015
(approx. $60 million in
2010)
100% fee-based:

Firm reservation charges
that provide a floor on
returns

Additional volumetric fees
based upon delivered
volumes
Area Infrastructure and Range Positions
Tennessee 300 Line

Connects Gulf coast and
Rockies supply with
northeastern markets

Capability to move 400 MMcfd
of Marcellus production
Transco Leidy Lateral

Connects Leidy storage facility
with northeastern markets

Capability to move 1.5 Bcfd of
Marcellus production through
physical or backhaul transport
Columbia Gas Transmission / Columbia Gulf
Marcellus Fairway
Areas under development
Texas Eastern Transmission
Tennessee Gas Pipeline
Dominion Transmission
Transcontinental Gas Pipeline
Marcellus Project Provides Significant Fee-Based Growth

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Distributable Cash Flow
(1)
vs. Distributions
Annual Adjusted EBITDA
(1)
$0
$40

$80
$120
$160
$200
2005
2006
2007
2008
2009
$0
$35
$70
$105
$140
$175
2005
2006
2007
2008
2009
Distributions
DCF
(1)
Adjusted EBITDA and Distributable Cash Flows are non-GAAP financial measures. See Appendix for a reconciliations of thes
Relatively moderate maintenance capital
expenditure requirements
Target distribution coverage ratio of 1.2x
Target long-term debt / EBITDA ratio of < 3.5x
Growth financed 50% debt / 50% equity
Debt / Adjusted EBITDA
(1)
Average: 2.7x
0.0x
1.0x
2.0x
3.0x
4.0x
2005
2006
2007
2008
2009
Financial Overview

23
Conservative Pro Forma Leverage with Strong Liquidity Profile
Balance Sheet as of June 30, 2010
(1)
Adjusted EBITDA is a non-GAAP financial measure. See Appendix for a reconciliation of Adjusted EBITDA to operating inc
(2)
On August 13, 2010, PVR closed on an amended 5 year credit facility of $850 million
(3)

Revolver availability includes adjustment for $1.6 million in letters of credit
Conservative Capitalization
Total Debt
646.5
$
Partners' Capital
459.4

Total Capitalization
1,105.9
$
LTM Adjusted EBITDA
(1)
190.6

Debt / Adjusted EBITDA
3.4x
Debt / Capitalization
58%
Revolver Capacity
(2)
850.0

Revolver Availability
(3)
501.9

Diversified, Relatively Low-Risk Asset Base
Strategically Located Coal Reserves and Midstream Assets
Stable and Predictable Coal Royalty Business
Solid Balance Sheet and Attractive Yield
Stable Cash Flows and Distribution Coverage
Well
Positioned
to

Capitalize
on
Partnership
Momentum
&
Industry
Trends
Hedged Midstream Business with Growing Fee-Based Volumes
Conclusion: Key Investment Highlights
24

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Appendix

PVR / PVG Merger

Hedging Strategy

Financial Information

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PVR and PVG will file a joint proxy statement/prospectus and other documents with the SEC in relation to the merger. Investo are urged to read these documents carefully when they become available because they will contain important information regarding PVR, PVG, and the transaction. A definitive joint proxy statement/prospectus will be sent to unitholders of PVR an PVG seeking their approvals as contemplated by the merger agreement. Once available, investors may obtain a free copy of th joint proxy statement/prospectus and other documents containing information about PVR and PVG, without charge, at the SE website at www.sec.gov. Copies of the joint proxy statement/prospectus and the SEC filings that will be incorporated by refer in the joint proxy statement/prospectus may also be obtained free of charge by contacting investor relations at 610-975-8204, o by accessing www.pvresource.com or www.pvgpholdings.com. PVR, PVG, and the officers and directors of the general partner of each partnership may be deemed to be participants in the solicitation of proxies from their security holders. Information about these entities and persons can be found in PVR s and PVG s Annual Reports on Form10-K for the year ended December 31, 2009. Additional information about such entities and persons may also be obtained from the joint proxy statement/prospectus when it becomes available.

PVR / PVG Merger Legal Notices

Certain statements by PVR and PVG contained herein that are not descriptions of historical facts are forward-looking statements by PVR and PVG within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E o the Securities Exchange Act of 1934, as amended. Words such as may, will, could, should, expect, plan, pr intend, anticipate, believe, estimate, predict, potential, pursue, target, continue, and similar expressi intended to identify such forward-looking statements. These forward-looking statements include, without limitation, the anticipated benefits and other aspects of the proposed merger, future financial and operating results and expectations and intentions with respect to future operations and services, approval of the proposed transaction by PVR and PVG unitholders, th satisfaction of the closing conditions to the proposed transaction, and the timing of the completion of the proposed transaction. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. Many of the factors that will determine PVR s and PVG's future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management s views only as of the date hereof. PVR and PVG undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as the result of new information, future events or otherwise. These risks as well as other risks, uncertainties and contingencies are discussed in mor detail in PVR s and PVG's joint press release and public periodic filings with the Securities and Exchange Commission (SEC including PVR s and PVG's Annual Reports on Form 10-K for the year ended December 31, 2009 and most recent Quarterly Reports on Form 10-Q.

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PVR / PVG Merger -
Transaction Summary

The boards of directors of PVR and PVG have agreed to a merger of the two partnerships in a tax-free, 100% equity exchange

Terms of the merger were approved by the conflicts committees and boards of PVR and

PVG

The merger is subject to approval by a majority of each of PVR s and PVG s unitholders

PVG has agreed to vote its approximate 37.6% interest in PVR units in favor of the merger

PVG unitholders will receive 0.98 PVR limited partnership (LP) units in exchange for each PVG LP unit they own

The merger would result in 38.3 million additional PVR units being issued and the cancellation of the approximate 19.6 million PVR LP units currently owned by PVG

Following the merger, the former PVG unitholders will own approximately 54% of PVR s LP units

The merger would result in PVR owning its General Partner and the cancellation of PVG s incentive distribution rights (IDRs)

The PVR management team will continue in their current roles

PVR s unitholders will elect all of the directors of its general partner s board of directors beginning in 2011

All three of PVG s independent directors are expected to join PVR s board of directors

The transaction is expected to result in dilution of PVR s distributable cash flow per unit of approximately 1.0% in 2011
(a)

Thereafter, the transaction is expected to be accretive as the economic benefits of the merger are realized
(a)
Accretion / dilution calculations are based on management assumptions

see PVR/PVG merger presentation dated 9/22/2010

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Current Structure
Penn Virginia
Resource Partners, L.P.
(NYSE: PVR)
Public
Unitholders
32.7 MM

Common Units
60.4% LP interest
Penn Virginia
GP Holdings, L.P.
(NYSE: PVG)
Public
Unitholders
39.1 MM
Common Units
100% LP interest
Penn
Virginia
Resource
GP, LLC
100% ownership
2% GP Interest
and Incentive
Distribution Rights
37.6% LP interest
19.6 MM PVR Common Units
Notes:
1)
Chart displays simplified organizational structure
2)
Units outstanding and ownership interests are
rounded approximations
Penn Virginia
Operating Co., LLC
and its subsidiaries

29
Post-Transaction Structure
Penn Virginia
Resource Partners, L.P.
(NYSE: PVR)
Public
Unitholders
71.0 Million

Common Units
100% LP interest
Penn Virginia
Operating Co., LLC
and its subsidiaries
Penn Virginia
Resource GP, LLC
100% (Indirect)
Non-economic GP interest
Notes:
1)
Chart displays simplified organizational structure
2)
Units outstanding and ownership interests are
rounded approximations

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Expected Merger Benefits

The merger is expected to provide benefits to both PVR and PVG unitholders, including:

Lower Cost of Capital

Elimination of the IDRs

will reduce PVR s cost of capital

Lower cost of capital enhances the cash accretion from investments in internal growth projects and acquisitions

Strengthens PVR s overall competitive position when pursuing growth opportunities

Simplified Structure

Provides a capital structure more easily understood by the investing public

Streamlines governance of PVR

Eliminates the potential for conflicts of interest from dual management roles

Reduces G&A costs associated with the elimination of one publicly traded entity

Enhanced Investor and Market Profile

Improves transparency for debt and equity investors

Attracts a broader investor base by increasing the public float and trading liquidity of the market for PVR s LP units

Provides PVR s unitholders the right to elect all of the directors of its general partner s board of directors

Based on the exchange ratio and upon closing of the merger, PVG unitholders quarterly cash distributions will increase 18%

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Derivative Hedging Strategy

PVR is long NGLs
and short natural gas

Active hedge strategy to mitigate commodity price risk

Exposed to frac
spread
risk through wellhead purchase
contract and to direct commodity price risk through percent-
of-proceeds contacts

Current and future hedges

2010 hedges are 60% of current price-sensitive volumes

2011 hedges are 58% of current price-sensitive volumes

Target hedging 50-60% of price sensitive exposure out 2 years

Sensitivity to commodity price changes is expected to
decrease as a result of increasing fixed-fee volumes
from the Marcellus Shale, Thunder Creek and
Crossroads

32
$51.2
30.6
-
13.0
(4.8)
1.3
-

(4.6)
$86.7
$104.5
58.2
31.8
(11.4)
(38.5)
(0.2)
-
(14.5)
$129.9
($ in millions)
Year Ended December 31,
2009
2008
2007
2006
2005
2004
Net Income
DD&A
Impairments
Total derivative losses (gains)
Cash settlements of derivatives
Equity earnings from jv s, net of distributions.
Other
Other CAPEX
Distributable Cash Flow
$34.3
18.6
-
-
-
0.6
-
(0.1)
$53.4
$73.9
37.5
-
13.2
(19.4)
1.3
4.6
(9.5)
$101.6
$56.6
41.5
-
50.2

(17.8)
(0.3)
-
(9.8)
$120.5
$65.2
70.2
1.5
22.7
3.0
(2.5)
-
(8.4)
$151.7
PVR -
Historical Distributable Cash Flow Summary
Distributable Cash Flow Reconciliation

33
(in thousands)
2009
2008
2007
2006
2005
Reconciliation of net income to Adjusted EBITDA:

Net income	$ 65,215	$ 104,500	$ 56,623	$ 73,928	$ 51,161
Depreciation, depletion and amortization	70,235	58,166	41,512	37,493	30,628
Interest expense	24,653	24,672	17,338	18,821	14,054
EBITDA	160,103	187,338	115,473	130,242	95,843
Impairments	1,511	31,801	-	-	-
Equity earnings, net of distributions received	(2,537)	(224)	(285)	1,317	1,269
Derivative losses (gains)	22,700	(11,357)	50,163	13,213	13,036
Net cash settlements of derivatives	3,000	(38,466)	(17,779)	(19,436)	(4,752)
Adjusted EBITDA	$ 184,777				

$ 169,092
$ 147,572
$ 125,336
$ 105,396
Reconciliation of cash flows from operating activities to Adjusted EBITDA:
Cash flows from operating activities
$ 159,972
$ 139,176
$ 127,824
$ 107,344
$ 93,712
Changes in operating assets and liabilities
5,308
6,529
2,243
(60)
(635)
Non-cash interest expense
(4,391)
(2,693)
(678)
(769)
(1,735)
Interest expense
24,653
24,672
17,338
18,821
14,054
Equity earnings, net of distributions received
2,537
224
285
(1,317)
(1,269)
Derivative gains (losses)
(22,700)
11,357
(50,163)
(13,213)
(13,036)
Cash settlement on derivatives
(3,000)
38,466
17,779
19,436
4,752
Impairments
(1,511)

(31,801)
-
-
-
Other
(765)
1,408
845
-
-
EBITDA
160,103
187,338
115,473
130,242
95,843
Impairments
1,511
31,801
-
-
-
Equity earnings, net of distributions received
(2,537)
(224)
(285)
1,317
1,269
Derivative losses (gains)
22,700
(11,357)
50,163
13,213
13,036
Net cash settlements of derivatives
3,000
(38,466)
(17,779)
(19,436)
(4,752)
Adjusted EBITDA
$ 184,777
$ 169,092
$ 147,572
$ 125,336
$ 105,396
Year Ended December 31,
PVR -
Historical Adjusted EBITDA Summary
Reconciliation of Adjusted EBITDA