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January 15, 2015

Via EDGAR

Mr. Brad Skinner
Senior Assistant Chief Accountant
Division of Corporation Finance
United States Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

Re: Penn Virginia Corporation
Form 10-K for Fiscal Year Ended December 31, 2013
Filed February 24, 2014
File No. 001-13283

Dear Mr. Skinner:

On December 19, 2014, the Staff of the Securities and Exchange Commission (the "Staff") issued a comment letter to Penn Virginia Corporation (the "Company") regarding the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (the "2013 Form 10-K"). The responses provided below are numbered to correspond to the Staff's comments, which have been reproduced here for ease of reference.

The Company appreciates the Staff's comments and has evaluated them carefully. In instances where the Company agrees additional disclosure is warranted, it is proposing to address such modifications in its upcoming Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Form 10-K"), which the Company expects to file by the end of February 2015. The Company does not believe the disclosures in the 2013 Form 10-K were misleading or deficient. The Company believes, therefore, that it would be most appropriate and cost beneficial to address the proposed modifications prospectively in the 2014 Form 10-K.

Form 10-K for the Fiscal Year Ended December 31, 2013

Properties, page 17

Proved Undeveloped Reserves, page 19

1. **We note that, during each of the last three years, you have converted 5% or less of your beginning-of-the-year proved undeveloped reserves. This is significantly below the 20% conversion rate implied by the 5 year limitation on proved undeveloped (PUD) reserves. To help us understand the activity impacting your reported PUD volumes, send us a roll-forward analysis that shows, for each of the four years 2010 through 2013, the following:**

- **Beginning and ending PUD volumes, broken out by the year of initial booking; and**
- **Changes during the year, broken out by year of initial booking, due to revisions, extensions, purchases, sales and conversions to proved developed reserves.**

Response: The following tables set forth the PUD roll-forward analyses for each of the years requested. In addition, we have presented the same PUD roll-forward analysis for PUDs initially booked in 2009 so that the totals correspond to the amounts presented on page 19 of the 2013 Form 10-K.

PUDs Initially Booked in 2009

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	0.54	2.22	82.9	16.58
Revisions of previous estimates	(0.22)	(1.60)	(65.3)	(12.70)
Extensions, discoveries and other additions	—	—	—	—
Purchase of reserves	—	—	—	—
Conversion to proved developed reserves	(0.04)	(0.08)	(0.8)	(0.24)
Proved undeveloped reserves at end of year	0.29	0.54	16.8	3.64

PUDs Initially Booked in 2010

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	1.51	7.26	134.5	31.19
Revisions of previous estimates	(0.38)	(2.57)	(40.0)	(9.63)
Extensions, discoveries and other additions	—	—	—	—
Purchase of reserves	—	—	—	—
Conversion to proved developed reserves	(0.01)	(0.03)	(0.3)	(0.08)
Proved undeveloped reserves at end of year	1.11	4.67	94.2	21.49

PUDs Initially Booked in 2011

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	1.16	0.09	0.5	1.3
Revisions of previous estimates	(0.61)	(0.03)	(0.2)	(0.67)
Extensions, discoveries and other additions	—	—	—	—
Purchase of reserves	—	—	—	—
Conversion to proved developed reserves	—	—	—	—
Proved undeveloped reserves at end of year	0.54	0.06	0.3	0.65

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PUDs Initially Booked in 2012

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	11.17	2.85	20.1	17.38
Revisions of previous estimates	(2.15)	(0.02)	(0.1)	(2.19)
Extensions, discoveries and other additions	—	—	—	—
Purchase of reserves	—	—	—	—
Conversion to proved developed reserves	(2.38)	(0.48)	(2.5)	(3.26)
Proved undeveloped reserves at end of year	6.64	2.35	17.5	11.92

PUDs Initially Booked in 2013

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	—	—	—	—
Revisions of previous estimates	—	—	—	—
Extensions, discoveries and other additions	27.70	5.20	27.0	37.40
Purchase of reserves	5.10	0.60	3.0	6.20
Conversion to proved developed reserves	—	—	—	—
Proved undeveloped reserves at end of year	32.80	5.80	30.0	43.60

2. **For each of the four years 2010 through 2013, provide a detailed explanation of how the projected development costs and drilling schedules for the first year utilized in compiling your estimates of the PUD reserves compared to the approved capital expenditure budget, operating plan and actual drilling schedules for the following year.**

   For example, explain how the projected development costs and development schedule for 2014 in the PUD reserve estimate as of December 31, 2013, compared to the approved capital expenditure budget, operating plan and actual drilling schedule for 2014.

Response: The Company prepares its capital budget using the development drilling and exploratory drilling categories. Because of the nature of the Company’s plays, development drilling often includes both PUD and non-PUD locations. The Company does not separately budget for PUD reserve development drilling. Obtaining drilling locations, capital expenditure and development cost numbers for PUD reserves only would take significant time since it would require the Company to prepare information that it does not prepare in the ordinary course of the Company’s business.

The Company has provided the requested information for all development drilling (both PUD and non-PUD) below in its response to Question #3.

3. **For each of the four years 2010 through 2013, explain how actual drilling, in terms of locations drilled and development costs incurred, in the subsequent year compared to the assumptions underlying your reserve estimates as of the end of the prior year.**

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For example, explain how actual drilling during 2014, in terms of locations drilled and development costs incurred, compared to the scheduled activity for 2014 contained in your reserve estimates as of December 31, 2013.

Response: The following tables show wells drilled, development drilling capital costs and estimated costs per well as modeled in the reserve reports for each of 2010, 2011, 2012 and 2013, as well as the budgeted and actual amounts of these items for the following year:

	Wells Drilled		Development Drilling Capital
	Gross	Net	($ in millions)
As included in year end 2010 reserve report	33	13.4	67.9
2011 approved budget	74	33.4	189.8
Actual as reported in 2011 Form 10-K	47	33.4	307.8
Wells in progress	7	5.8	

	Wells Drilled		Development Drilling Capital
	Gross	Net	($ in millions)
As included in year end 2011 reserve report	34	23.6	141.5
2012 approved budget	45	36.7	309.0
Actual as reported in 2012 Form 10-K	36	27.8	287.4
Wells in progress	3	2.7	

	Wells Drilled		Development Drilling Capital
	Gross	Net	($ in millions)
As included in year end 2012 reserve report	50	41.8	378.0
2013 approved budget	43	31.0	317.0
Actual as reported in 2013 Form 10-K	59	34.6	405.0
Wells in progress	16	11.5	

	Wells Drilled		Development Drilling Capital
	Gross	Net	($ in millions)
As included in year end 2013 reserve report	100	61.9	561.0
2014 approved budget	98	52.5	528.9
Actual **	83	51.0	608.0
Wells in progress	25	12.5	

** The actual amounts shown for 2014 are estimates only and will not be finalized until the filing of the 2014 Form 10-K.

4. **Information provided in the schedules of drilling activity on page 22 indicates that you did not drill any wells in your East Texas or Mid-Continent regions during the last three years or in your Appalachia region during the last two years. Quantify for us the extent to which you have reported PUD reserves attributable to these regions as of your three most recent year ends. To the extent you have reported PUD reserves attributable to these regions, explain how this is consistent with the apparent lack of drilling activity.**

Response: The Company believes that the Staff's question inadvertently referenced the Company's Mid-Continent region instead of the Company's Mississippi region. The Company did, in fact, drill wells in the Mid-Continent region in each of the last three years, but did not drill any wells in the Mississippi region in any of the last three years.

The following table shows the total PUD reserves at the end of each of 2013, 2012 and 2011, as well as the contributions to those PUD reserves from each of the Company's Appalachia, Mississippi and East Texas regions:

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Year end 2013 total proved undeveloped reserves	41.4	13.4	158.9	81.3
Appalachia proved undeveloped reserves	0.0	0.0	0.0	0.0
Mississippi proved undeveloped reserves	0.0	0.0	26.1	4.4
East Texas proved undeveloped reserves	1.2	5.2	88.2	21.2
Year end 2012 total proved undeveloped reserves	14.4	12.4	238.1	66.5
Appalachia proved undeveloped reserves	0.0	0.0	2.4	0.4
Mississippi proved undeveloped reserves	0.1	0.0	48.3	8.1
East Texas proved undeveloped reserves	1.7	9.3	167.3	38.9
Year end 2011 total proved undeveloped reserves	7.0	12.1	339.4	75.6
Appalachia proved undeveloped reserves	0.0	0.0	33.3	5.5
Mississippi proved undeveloped reserves	0.1	0.0	88.9	14.9
East Texas proved undeveloped reserves	1.7	10.2	195.7	44.5

With respect to the Appalachian region, please note that PUD reserves associated with that region were de minimis at year end 2013 and 2012. With respect to 2011, PUD reserves attributable to the Appalachia region constituted less than 10% of the Company's total PUD reserves. The Company believes that the PUD reserves attributed to the region in 2011 were appropriate given the drilling activities undertaken in that region during 2011, 2010 and 2009. Moreover, the Company sold substantially all of its Appalachia operations in 2012.

With respect to the Mississippi and East Texas regions, please note that PUD reserves associated with those regions declined significantly over the applicable three year period. The PUD reserves attributed to Mississippi were substantially all natural gas and the PUD reserves attributed to East Texas were primarily natural gas. The Company had substantial natural gas PUD reserves in 2009 when natural gas prices dropped precipitously. While waiting for natural gas prices to recover, the Company focused its drilling activities on regions with more oil and NGL potential. The Company began writing off those natural gas PUD reserves over the next several years as natural gas prices did not recover as expected. The Company believes that its booking of Mississippi and East Texas PUD reserves was appropriate given the uncertainty of natural gas prices. Moreover, the Company sold all of its Mississippi operations in 2014 and no PUD reserves will be reflected for that region in the Company's 2014 reserves. In addition, the Company expects that substantially all of the remaining PUDs reflected for the East Texas region in the Company's 2013 reserves will be written off in its 2014 reserves.

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Management's Discussion and Analysis of Financial Condition and Results of Operations, page 27

5. **We note you present your cash operating margin for each financial statement period and discuss changes in this measure from period to period. Please define how you calculate this measure within your discussion. To the extent it represents a non-GAAP measure, please include within your document the information set forth in Item 10(e)(i) of Regulation S-K.**

Response: Cash operating margin per barrel of oil equivalent ("BOE") as presented on page 28 in the 2013 Form 10-K is calculated by subtracting total operating costs per BOE from the realized price of the Company's total production per BOE as presented in the table on page 27. The presentation below includes a comprehensive recalculation of the Company's cash operating margin per BOE for the periods presented.

Determination of Cash Operating Margin per BOE, a non-GAAP Measure
For the Years Ended December 31,
($ in thousands, except per BOE amounts)

	2013			2012			2011		
			$/BOE			$/BOE			$/BOE
Total production (MBOE)[1]	6,824			6,513			7,759		
Product revenues[2]		$430,693	$63.11		$310,484	$47.67		$300,046	$38.67
Production and lifting costs:									
Lease operating[3]		35,461	5.20		31,266	4.80		36,988	4.77
Gathering, processing and transportation[3]		12,839	1.88		14,196	2.18		15,157	1.95
Production and ad valorem taxes[3]		22,404	3.28		10,634	1.63		13,690	1.76
General and administrative:									
General and administrative expenses, as reported[3]	53,998		7.91	45,900		7.05	48,328		6.23
Equity-classified share-based compensation[4]	(5,781)		(0.84)	(6,347)		(0.98)	(7,430)		(0.96)
Acquisition transaction expenses[4,5]	(2,587)		(0.38)	—		—	—		—
Restructuring expenses[4,5]	(7)		(0.00)	(1,292)		(0.20)	(2,351)		(0.30)
Adjusted general and administrative		45,623	6.69		38,261	5.87		38,547	4.97
Total costs		116,327	17.05		94,357	14.48		104,382	13.45
Cash operating margin as disclosed		$314,366	$46.06		$216,127	$33.19		$195,664	$25.22

1 Production volume as discussed and disclosed on pages 27, 30 and 36 of the 2013 Form 10-K
2 Product revenues as discussed and disclosed on pages 27, 31 and 37 of the 2013 Form 10-K.
3 Operating expenses as discussed and disclosed on pages 32-33 and 38-39 and presented on the Statement of Operations on page 53 of the 2013 Form 10-K.
4 Certain general and administrative expenses as discussed and disclosed on pages 27, 33 and 39 of the 2013 Form 10-K.
5 Acquisition transaction and restructuring expenses are cash-based expenses that have been excluded from general and administrative expenses for all periods presented in the presentation of cash operating margin per BOE in order to highlight changes in that non-GAAP measure from year-to-year on a comparable basis

The Company acknowledges that its presentation of cash operating margin per BOE represents a non-GAAP measure and that the Company did not present a comparable measure calculated in accordance with GAAP or a reconciliation from our non-GAAP measure to the comparable GAAP measure. The presentation below includes such reconciliation for the periods presented.

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Reconciliation of Loss Before Income Taxes to Cash Operating Margin
For the Years Ended December 31,
($ in thousands, except per BOE amounts)

	2013	2012	2011
Loss before income taxes	$(220,766)	$ (173,291)	$ (221,070)
Adjustments to reconcile loss before income taxes to cash operating margin:			
Other income	(147)	(116)	(335)
Derivatives expense (income)	20,852	(36,187)	(15,651)
Loss on extinguishment of debt	29,174	3,164	25,421
Interest expense	78,841	59,339	56,216
Other expenses	—	—	1,096
Loss on firm transportation commitment	—	17,332	—
Impairments	132,224	104,484	104,688
Depreciation, depletion and amortization	245,594	206,336	162,534
Exploration	20,994	34,092	78,943
Other revenues (non-product)	(1,041)	(2,383)	(2,389)
Loss (gain) on sale of property and equipment	266	(4,282)	(3,570)
Equity-classified share-based compensation	5,781	6,347	7,430
Acquisition transaction expenses	2,587	—	—
Restructuring expenses	7	1,292	2,351
Cash operating margin	$ 314,366	$ 216,127	$ 195,664
Total production (MBOE)	6,824	6,513	7,759
Cash operating margin per BOE	$46.06	$33.19	$25.22

The Company believes that cash operating margin per BOE, while not a significant factor in the evaluation of the Company, is a measure that security analysts and investors sometimes use to compare the Company's profitability with that of other oil and gas companies, as well as to other time periods.

The Company does not believe that cash operating margin per BOE constitutes material information such that amendment of the 2013 Form 10-K would serve a meaningful purpose at this time. If the Company presents this non-GAAP measure in its future filings, including the 2014 Form 10-K, it will define the computation of the measure and will present, with equal prominence, the most directly comparable financial measure calculated in accordance with GAAP and a reconciliation to that measure.

In connection with this response letter, the Company acknowledges that:

- the Company is responsible for the adequacy and accuracy of the disclosure in its filings with the Commission;
- Staff comments or changes to disclosure in response to Staff comments do not foreclose the Commission from taking any action with respect to the Company's filings; and
- the Company may not assert Staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

Please contact me at (610) 687-8900 if you need additional information or would like to discuss any questions or comments.

Sincerely,

/s/ Steven A. Hartman

Steven A. Hartman
Senior Vice President and
Chief Financial Officer

cc: Nancy M. Snyder
Jenifer Gallagher