November 9, 2015

# Penn Virginia Corporation Announces Third Quarter 2015 Results

*ACTIVELY REVIEWING FINANCING AND DEBT RESTRUCTURING ALTERNATIVES*

*AVERAGE IP AND 30 DAY RATES UP 88% AND 59% OVER SECOND QUARTER*

*AVERAGE WELL COST DOWN 30% FROM SECOND QUARTER*

*NEW BORROWING BASE OF $275 MILLION, IN LINE WITH EXPECTATIONS*

RADNOR, Pa., Nov. 9, 2015 (GLOBE NEWSWIRE) -- Penn Virginia Corporation (NYSE:PVA) today reported financial results for the three months ended September 30, 2015 and provided updates of its operations and guidance.

**Key Highlights**

Third quarter 2015 results compared, as applicable, to second quarter 2015 results were as follows:

- Total production was 20,976 barrels of oil equivalent (BOE) per day (BOEPD), compared to 23,519 BOEPD.
  - Total production was above the midpoint of production guidance of 18,500 to 22,800 BOEPD.
- The average initial potential (IP) and 30-day rates for 11 Eagle Ford wells turned in line were 1,501 and 790 BOEPD, up 88% and 59% compared to 798 and 497 BOEPD for 16 wells turned in line in the second quarter.
- Gross drilling and completion costs for the 11 wells, including facilities, averaged $5.7 million per well, approximately 30% lower than the average cost of the 16 second quarter wells.
  - The decrease in average well cost was driven by a transition to drilling exclusively two-string wells, whereas only three of the second quarter wells were two-string wells. In addition, seven of the third quarter wells were slickwater stimulated and all of the third quarter wells were fractured with approximately 46% more proppant per stage, on average, than second quarter wells.
- Product revenues, including derivatives, were $93.0 million, compared to $118.0 million.
  - Realized oil, gas and natural gas liquids (NGLs) prices were $69.19 per barrel, $2.68 per thousand cubic feet (Mcf) and $9.81 per barrel, compared to $82.44 per barrel, $2.54 per Mcf and $13.53 per barrel, including hedges.
  - Product revenues per BOE were $48.17, compared to $55.12, including hedges.
- Production costs, including lease operating expense, gathering, processing and transportation expenses and production and ad valorem taxes, decreased 8% to $20.4 million from $22.3 million.
- Recurring general and administrative (G&A) costs decreased 12% to $8.2 million from $9.4 million.
- Adjusted EBITDAX, a non-GAAP (generally accepted accounting principles) measure, was $65.0 million, compared to $85.5 million.

Other updates included:

- The borrowing base under the revolving credit facility (Revolver) was recently redetermined to $275 million.
  - The lower borrowing base was in line with our expectations.
  - At September 30, 2015, our pro forma financial liquidity was $136 million and our leverage ratio was 3.9 times.
  - Year-end 2015 liquidity is expected to be $103 to $118 million.
- Preliminarily, we estimate 2016 capital expenditures to be between $140 and $160 million, down from earlier preliminary guidance of $200 to $250 million.
  - Fourth quarter 2016 oil production is now expected to be approximately 5% less than fourth quarter 2015.

Definitions of non-GAAP financial measures and reconciliations of these non-GAAP financial measures to GAAP-based measures appear later in this release.

**Management Comment**

Edward B. Cloues, II, Chairman and interim Chief Executive Officer stated, "Our third quarter results were largely as expected, despite lower than anticipated oil prices, as our operating costs continued to decrease. Our third quarter production came in slightly above the midpoint of third quarter guidance, due primarily to the higher productivity of our most recent wells. In particular, we were encouraged with the early results of our most recent seven two-string, slickwater fracked wells in the Lower Eagle Ford, both in terms of their average cost and initial productivity. The last five of these wells, also utilizing zipper fracs, were on average the best wells we have drilled out of nearly 330 producing wells we and our partners have drilled over the past five years. The higher initial production of our wells turned in line in the third quarter, and the lower costs of those wells, which were 30% lower than the average cost of wells we turned in line in the second quarter, should generate higher than historical internal rates of return even in the current price environment.

"We will continue to focus our drilling efforts on two-string, Lower Eagle Ford wells in Gonzales County and northwestern Lavaca County, where we believe our rates of return are optimized. The redirection of our drilling program to this lower-cost area, where we have experienced higher productivity with the slickwater fracs, has led us to reduce preliminary capital expenditures guidance for 2016 for a 1-rig drilling program, as detailed later in this release."

Mr. Cloues concluded, "With respect to financial liquidity, our borrowing base redetermination, while lower, was in line with our expectations given the current commodity price environment. To further supplement liquidity, during the third quarter and in early October we sold our East Texas and certain non-core Eagle Ford assets for gross proceeds of $88 million. However, we anticipate that we will exceed the total debt leverage covenant in the Revolver at the end of the first quarter of 2016, which would require us to seek a waiver from our bank lenders, which may or may not be forthcoming. Consequently, we are actively reviewing various financing and debt restructuring alternatives in an attempt to shore up our overall liquidity and relieve our dependence upon the Revolver as our sole source of external funding."

**Third Quarter 2015 Results**

*Overview of Results*

Operating income was $3.6 million in the third quarter of 2015, compared to an operating loss of $41.0 million in the second quarter of 2015. This $44.6 million improvement was due primarily to $50.8 million of gains related to asset sales and a $16.2 million decrease in operating expenses, partially offset by a $22.4 million decrease in product revenues.

Net income attributable to common shareholders for the third quarter was $20.0 million, or $0.25 per diluted share, compared to net loss of $86.2 million, or $1.19 per diluted share, in the prior quarter. The primary reasons for the $106.2 million improvement were the $44.6 million increase in operating income and a $60.2 million increase in derivatives income, which includes mark-to-market adjustments. Adjusted net loss attributable to common shareholders, a non-GAAP measure which includes our preferred stock dividend but excludes the effects of non-cash derivatives expense and other items that affect comparability to other periods, was $43.3 million, or $0.60 per diluted share, for the third quarter compared to a loss of $31.6 million, or $0.44 per diluted share, in the prior quarter. The primary reasons for the $11.6 million increase in the loss were the $22.4 million decrease in product revenues and a $2.6 million decrease in cash settlements of derivatives, partially offset by the $16.2 million decrease in operating expenses.

*Production*

As shown in the table below, total production in the third quarter of 2015 was 20,976 BOEPD, compared to 23,519 BOEPD in the second quarter of 2015, with a 1,731 BOEPD decrease in the Eagle Ford and an 812 BOEPD decrease in other areas, primarily related to the sale of East Texas assets in August 2015. Pro forma for the sale of East Texas, production declined by 1,764 BOEPD to 19,857 BOEPD in the third quarter of 2015 from 21,621 BOEPD in the prior quarter.

| | Total and Daily Equivalent Production for the Three Months Ended | | | | | |
|---|---|---|---|---|---|---|
| **Region / Play Type** | **Sept. 30, 2015** | **June 30, 2015** | **Sept. 30, 2014** | **Sept. 30, 2015** | **June 30, 2015** | **Sept. 30, 2014** |
| | | (in MBOE) | | | (in BOEPD) | |
| **Eagle Ford Shale** | 1,705 | 1,844 | 1,557 | 18,528 | 20,259 | 16,929 |
| **Mid-Continent** | 117 | 119 | 258 | 1,271 | 1,302 | 2,802 |
| **Other** | 108 | 177 | 274 | 1,177 | 1,958 | 2,975 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Totals** | **1,930** | **2,140** | **2,089** | **20,976** | **23,519** | **22,706** |
| **Pro Forma Totals(1)** | **1,827** | **1,967** | **1,712** | **19,857** | **21,621** | **18,617** |

Note - Numbers may not add due to rounding. MBOE equals one thousand barrels of oil equivalent.

(1) Pro forma to exclude volumes from divested Mississippi and East Texas properties, as well as the third quarter 2014 Mid-Continent adjustment.

*Product Revenues*

Total product revenues decreased by $22.4 million, or 27%, to $60.7 million, or $31.45 per BOE, in the third quarter of 2015, from $83.1 million, or $38.84 per BOE, in the second quarter of 2015, due primarily to a 19% decrease in the realized oil equivalent price and an 11% decrease in production. For the third quarter, the realized oil price decreased by 23%, the realized natural gas price increased by 5% and the realized NGL price decreased by 27% compared to the second quarter of 2015. Including derivatives, total product revenues were $93.0 million, or $48.17 per BOE, in the third quarter of 2015, compared to $118.0 million, or $55.12 per BOE, in the second quarter of 2015.

*Operating Expenses*

As discussed below, third quarter 2015 total direct operating expenses, excluding share-based compensation and non-recurring expenses, decreased by $3.0 million to $28.7 million, or $14.87 per BOE produced, from $31.7 million, or $14.80 per BOE produced, in the second quarter of 2015.

- Lease operating expense increased by $0.4 million to $11.3 million, or $5.86 per BOE, from $10.9 million, or $5.10 per BOE, due to increased compression and saltwater disposal expenses, partially offset by decreased workover and chemicals and fluids expenses.
- Gathering, processing and transportation expense decreased by $0.7 million to $5.7 million, or $2.93 per BOE, from $6.4 million, or $2.98 per BOE, due to decreased production volumes.
- Production and ad valorem taxes decreased by $1.5 million to $3.5 million, or 5.7% of product revenues, from $5.0 million, or 6.0% of product revenues, due to lower commodity prices.
- Recurring G&A expense decreased by $1.2 million to $8.2 million, or $4.27 per BOE, from $9.4 million, or $4.40 per BOE. The decrease in recurring G&A expense was due primarily to lower consulting and professional fees and salary and wages expense.

Depletion, depreciation and amortization expense in the third quarter of 2015 decreased by $8.5 million to $76.9 million, or $39.82 per BOE, from $85.4 million, or $39.91 per BOE, in the second quarter.

*Capital Expenditures*

During the third quarter of 2015, capital expenditures were $40 million, a decrease of $54 million, or 58%, compared to $94 million in the second quarter of 2015, consisting of:

- A decrease of approximately $48 million for drilling and completion activities, to approximately $40 million.
- A net decrease of approximately $6 million to approximately zero for pipeline, gathering, facilities, seismic, leasehold acquisition and other capital expenditures.

*Capital Resources and Liquidity, Interest Expense and Impact of Derivatives*

As of September 30, 2015, we had total debt of $1,215 million, consisting of $300 million principal amount of 7.25% senior unsecured notes due 2019, $775 million principal amount of 8.50% senior unsecured notes due 2020 and $140 million drawn under the Revolver, down $72 million from June 30, 2015. In November 2015, the borrowing base under the Revolver was reduced from $395 million to $275 million, which was in line with our expectations. Together with cash and equivalents of $3 million and net of letters of credit of $2 million, our financial liquidity was $256 million at September 30, 2015. Pro forma liquidity, after giving effect to the new borrowing base of $275 million, was $136 million.

Our total debt leverage ratio under the Revolver at September 30, 2015 was 3.9 times trailing twelve months' Adjusted EBITDAX of $313 million. The maximum leverage ratio allowable during the third quarter of 2015 under the Revolver was 4.75 times. An additional covenant for credit exposure, defined as all outstanding borrowings under the Revolver plus any outstanding letters of credit, has a maximum allowable ratio of 2.75 times through March 31, 2017. At September 30, 2015, this ratio was 0.5 times.

During the third quarter, interest expense was $23.0 million, of which $21.8 million was cash interest expense, unchanged from the second quarter.

During the third quarter, derivatives income was $44.7 million, compared to derivatives expense of $15.5 million in the second quarter. Third quarter cash settlements of derivatives resulted in net cash receipts of $32.3 million, compared to $34.8 million of net cash receipts in the second quarter.

*Derivatives Update*

To support our operating cash flows, we hedge a portion of our oil and natural gas production at predetermined prices or price ranges. Currently, we have hedged 11,000 barrels of daily crude oil production during the fourth quarter of 2015, or about 90% to 100% of our expected oil production, at a weighted average floor/swap price of $89.86 per barrel. We have sold put options for 5,000 barrels of daily crude oil production during the fourth quarter of 2015, with all put options sold at a strike price of $70.00 per barrel. For 2016, we have hedged 6,000 barrels of daily crude oil production at a weighted average floor/swap price of $80.41 per barrel. We currently do not have any natural gas derivatives.

Please see the Derivatives Table included in this release for our current derivative positions.

**Full-Year 2015 Guidance Update and Preliminary 2016 Guidance**

Full-year 2015 guidance highlights are as follows:

- Production of approximately 21,300 to 21,800 BOEPD, compared to previous guidance of approximately 20,700 to 22,600 BOEPD.
    - 2015 crude oil production of approximately 13,200 to 13,500 barrels of oil per day (BOPD), compared to previous guidance of 13,050 to 14,350 BOPD.
    - Production in the fourth quarter of 2015 is expected to range between approximately 16,200 and 18,100 BOEPD, compared to previous guidance of between 16,300 and 19,600 BOEPD.
- Product revenues, excluding the impact of any derivatives, are expected to be $264 to $269 million, compared to previous guidance of $284 to $307 million.
    - Our crude oil revenue estimate assumes realized pricing of West Texas Intermediate (WTI) crude oil benchmark pricing of approximately $45 per barrel, compared to previous guidance of $55 per barrel. Benchmark (Henry Hub) natural gas pricing is assumed to be $2.56 per Mcf, compared to previous guidance of $2.88 per Mcf, while NGL pricing is assumed to be 19% of the WTI price.
    - Cash receipts from the settlement of derivatives are expected to be $134 million, based on the foregoing assumptions, compared to previous guidance of $127 million.
- Adjusted EBITDAX, a non-GAAP measure, is expected to be $280 to $284 million, compared to previous guidance of $285 to $310 million.
- Capital expenditures are expected to be $316 to $324 million, compared to previous guidance of $325 to $345 million.
    - Drilling and completion capital expenditures are expected to be $296 to $302 million, compared to previous guidance of $305 to $320 million.
    - Pipeline, gathering, facilities, seismic and other capital expenditures are expected to be $6 to $7 million, compared to previous guidance of $5 to $8 million.
    - Lease acquisition capital expenditures are expected to be $14 to $15 million, essentially unchanged compared to previous guidance.

Please see the Guidance Table included in this release for guidance estimates for fourth quarter and full-year 2015.

Preliminarily, and based on crude oil prices, specifically $48 to $52 per barrel WTI, we expect to spend $140 to $160 million in capital expenditures during 2016, with fourth quarter 2016 oil production approximately 5% lower than the midpoint of fourth quarter 2015 oil production guidance (overall production approximately 10% lower). This compares to previous preliminary guidance, which assumed a $55 to $60 per barrel WTI crude oil pricing, of $200 to $250 million in capital expenditures during 2016. The 2016 preliminary capital budget will be funded by anticipated year-end 2015 liquidity and 2016 cash flows from operating activities.

2015 estimates and 2016 preliminary estimates are meant to provide guidance only and are subject to revision as the operating environment changes.

**Eagle Ford Shale Operational Update**

*Third Quarter 2015 Update*

Third quarter production from our Eagle Ford operations was 18,528 BOEPD, a 9% decrease from the 20,259 BOEPD produced in the second quarter of 2015. Approximately 69% of our third quarter Eagle Ford production was from crude oil, 18% was from NGLs and 13% was from natural gas. The decrease was attributable primarily to our reduction in drilling activity as the year progressed, in light of lower oil and gas prices.

*Well Cost Reductions and Improved Well Results*

The average gross well cost for 11 (two-string) wells turned in line during the third quarter of 2015 was approximately $5.7 million, down 30% from an average of $8.2 million for 16 (two-string and three-string wells) wells turned in line in the second quarter of 2015. The decrease in average well cost was driven by a transition to drilling exclusively two-string wells, whereas only three of the second quarter wells were two-string wells. In addition, seven of the third quarter wells were slickwater stimulated and all of the third quarter wells were fractured with approximately 46% more proppant per stage, on average, than second quarter wells.

*Recent Eagle Ford Well Results*

Below are the results and statistics for Eagle Ford wells over the past five quarters: (2)

| | | Averages | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Peak Gross Daily Production Rates(3) | | | 30-Day Average Gross Daily Production Rates(3) | | |
| | Gross / Net Wells | Lateral Length | Frac Stages | Proppant | Oil Rate | Equivalent Rate | Oil Percentage | Oil Rate | Equivalent Rate | Oil Percentage |
| | | *Feet* | | *lbs.* | *BOPD* | *BOEPD* | | *BOPD* | *BOEPD* | |
| **Time Period** | | | | | | | | | | |
| 2014 - 3rd quarter | 22 / 12.2 | 5,813 | 27.4 | 10,129,710 | 1,050 | 1,244 | 85% | 659 | 777 | 85% |
| 2014 - 4th quarter | 23 / 17.1 | 5,486 | 25.7 | 9,849,071 | 880 | 1,256 | 70% | 634 | 900 | 72% |
| 2015 - 1st quarter | 25 / 13.7 | 6,345 | 27.2 | 8,089,820 | 1,048 | 1,254 | 84% | 681 | 805 | 85% |
| 2015 - 2nd quarter | 16 / 11.4 | 6,008 | 24.4 | 7,014,972 | 604 | 798 | 76% | 388 | 497 | 77% |
| 2015 - 3rd quarter | 11 / 8.5 | 5,040 | 21.2 | 9,082,417 | 1,381 | 1,501 | 93% | 726 | 790 | 92% |
| **Totals and averages** | **97 / 62.9** | **5,817** | **25.7** | **8,904,885** | **973** | **1,205** | **81%** | **622** | **769** | **82%** |
| | | | | | | | | | | |
| **Operating Area** | | | | | | | | | | |
| Peach Creek | 14 / 8.6 | 5,128 | 23.6 | 9,677,214 | 1,364 | 1,488 | 92% | 756 | 819 | 93% |
| Rock Creek / Bozka | 8 / 3.7 | 5,461 | 25.9 | 9,517,026 | 1,313 | 1,486 | 88% | 910 | 1,032 | 88% |
| Upper Eagle Ford | 30 / 24.3 | 6,002 | 26.0 | 8,724,670 | 614 | 960 | 68% | 465 | 710 | 70% |
| Lavaca "Beer Area" | 20 / 9.4 | 6,032 | 27.2 | 9,505,123 | 1,128 | 1,387 | 81% | 715 | 862 | 82% |
| Shiner | 9 / 6.8 | 5,932 | 24.8 | 7,179,445 | 899 | 1,205 | 73% | 546 | 715 | 75% |
| Shallow Gonzales | 16 / 10.0 | 5,917 | 25.6 | 8,481,194 | 983 | 1,049 | 94% | 579 | 615 | 94% |
| **Totals and averages** | **97 / 62.9** | **5,817** | **25.7** | **8,904,885** | **973** | **1,205** | **81%** | **622** | **769** | **82%** |

(2) Excludes two Upper Eagle Ford wells and one Lower Eagle Ford well which had mechanical issues.

(3) Wellhead rates only; the natural gas associated with these wells is yielding between 135 and 155 barrels of NGLs per million cubic feet.

Since the end of the second quarter of 2015, we have turned in line 11 (8.5 net) operated wells. As a group, these 11 wells had an average IP rate of 1,501 BOEPD over an average of 21.2 frac stages, with 93% of production from crude oil, compared to 798 BOEPD over an average of 24.4 stages for 16 second quarter wells. All of the third quarter wells were drilled in the Lower Eagle Ford and had a 30-day average rate of 790 BOEPD, with 92% of production from crude oil, compared to an average of 497 BOEPD for the second quarter wells. The average amount of proppant per stage for these 11 wells was approximately 422,000 pounds and the average amount of proppant per lateral foot was approximately 1,800 pounds, compared to approximately 290,000 pounds per stage and 1,170 pounds per lateral foot in the second quarter of 2015. We believe the strong improvement in early-time production rates is attributable to the use of slickwater stimulations, continued use of "zipper" fracs for alternating laterals on multi-well pads and increased frac intensity as measured by the increased proppant pumped per stage.

*Drilling Program Outlook*

For the remainder of 2015 and for 2016, due primarily to anticipated low oil prices, we will continue to focus our efforts on drilling, using one rig, less costly two-string Lower Eagle Ford wells in Gonzales County and northwestern

Lavaca County where our economics are optimized.

**Third Quarter 2015 Conference Call**

A conference call and webcast, during which management will discuss third quarter 2015 financial and operational results, is scheduled for Tuesday, November 10, 2015 at 10:00 a.m. ET. Prepared remarks will be followed by a question and answer period. Investors and analysts may participate via phone by dialing toll free 1-877-316-5288 (international: 1-734-385-4977) five to 10 minutes before the scheduled start of the conference call (use the conference code 59451145), or via webcast with presentation slides by logging on to our website, www.pennvirginia.com, at least 15 minutes prior to the scheduled start of the call to download and install any necessary audio software. A telephonic replay will be available for two weeks beginning approximately 24 hours after the call. The replay can be accessed by dialing toll free 1-855-859-2056 (international: 1-404-537-3406) and using the replay code 59451145. In addition, an on-demand replay of the webcast will also be available for two weeks at our website beginning approximately 24 hours after the webcast.

*Penn Virginia Corporation (NYSE:PVA) is an independent oil and gas company engaged in the exploration, development and production of oil, NGLs and natural gas in various domestic onshore regions of the United States, with a primary focus in the Eagle Ford Shale in south Texas. For more information, please visit our website at www.pennvirginia.com.*

Certain statements contained herein that are not descriptions of historical facts are "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following: the volatility of commodity prices for oil, natural gas liquids, or NGLs and natural gas; our ability to develop, explore for, acquire and replace oil and natural gas reserves and sustain production; our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations; our ability to maintain adequate financial liquidity and to access adequate levels of capital on reasonable terms; compliance with debt covenants; reductions in the borrowing base under the Revolver; our ability to continue to borrow under the Revolver; any impairments, write-downs or write-offs of our reserves or assets; the projected demand for and supply of oil, NGLs and natural gas; our ability to contract for drilling rigs, supplies and services at reasonable costs; our ability to obtain adequate pipeline transportation capacity for our oil and gas production at reasonable cost and to sell the production at, or at reasonable discounts to, market prices; the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from estimated proved oil and natural gas reserves; drilling and operating risks; our ability to compete effectively against other oil and gas companies; our ability to successfully monetize select assets and repay our debt; leasehold terms expiring before production can be established; environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance; the timing of receipt of necessary regulatory permits; the effect of commodity and financial derivative arrangements; the occurrence of unusual weather or operating conditions, including force majeure events; our ability to retain or attract senior management and key technical employees; counterparty risk related to the ability of these parties to meet their future obligations; compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters; physical, electronic and cybersecurity breaches; uncertainties relating to general domestic and international economic and political conditions; and other risks set forth in our filings with the Securities and Exchange Commission (SEC).

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the SEC. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management's views only as of the date hereof. All subsequent written and oral forward-looking statements attributable to PVA or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

**PENN VIRGINIA CORPORATION**

**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - unaudited**

(in thousands, except per share data)

| | Three months ended | Three months ended | Nine months ended |
|---|---|---|---|
| | September 30, | June 30, | September 30, |

| | 2015 | 2014 | 2015 | 2015 | 2014 |
|---|---|---|---|---|---|
| **Revenues** | | | | | |
| Crude oil | $ 51,124 | $ 118,716 | $ 70,672 | $ 180,964 | $ 336,382 |
| Natural gas liquids (NGLs) | 3,254 | 9,790 | 5,191 | 13,841 | 27,200 |
| Natural gas | 6,312 | 13,354 | 7,260 | 22,143 | 47,859 |
| Total product revenues | 60,690 | 141,860 | 83,123 | 216,948 | 411,441 |
| Gain (loss) on sales of property and equipment, net | 50,828 | 63,520 | 66 | 50,803 | 120,295 |
| Other | 466 | 16 | 427 | 2,376 | 2,886 |
| Total revenues | 111,984 | 205,396 | 83,616 | 270,127 | 534,622 |
| **Operating expenses** | | | | | |
| Lease operating | 11,304 | 14,761 | 10,907 | 33,780 | 36,878 |
| Gathering, processing and transportation (a) | 5,654 | 5,428 | 6,383 | 19,535 | 12,605 |
| Production and ad valorem taxes | 3,483 | 7,690 | 4,967 | 13,139 | 22,505 |
| General and administrative (excluding equity-classified share-based compensation) (b) | 8,153 | 10,540 | 10,363 | 29,496 | 40,417 |
| Total direct operating expenses | 28,594 | 38,419 | 32,620 | 95,950 | 112,405 |
| Share-based compensation - equity classified awards (c) | 1,263 | 987 | 1,116 | 3,369 | 2,638 |
| Exploration | 1,673 | 1,986 | 4,362 | 11,922 | 13,995 |
| Depreciation, depletion and amortization | 76,850 | 71,999 | 85,416 | 253,056 | 215,623 |
| Impairments | -- | 6,084 | 1,084 | 1,084 | 123,992 |
| Total operating expenses | 108,380 | 119,475 | 124,598 | 365,381 | 468,653 |
| **Operating income (loss)** | 3,604 | 85,921 | (40,982) | (95,254) | 65,969 |
| **Other income (expense)** | | | | | |
| Interest expense | (22,985) | (21,953) | (23,023) | (68,021) | (67,716) |
| Derivatives | 44,701 | 66,457 | (15,495) | 52,073 | 8,130 |
| Other | (44) | 1,349 | (540) | (586) | 1,380 |
| Income (loss) before income taxes | 25,276 | 131,774 | (80,040) | (111,788) | 7,763 |
| Income tax (expense) benefit | 624 | (42,113) | (89) | 394 | 339 |
| **Net income (loss)** | 25,900 | 89,661 | (80,129) | (111,394) | 8,102 |
| Preferred stock dividends (d) | (5,935) | (7,641) | (6,067) | (18,069) | (11,081) |
| Induced conversion of preferred stock | -- | (888) | -- | -- | (4,256) |
| **Net income (loss) attributable to common shareholders** | $ 19,965 | $ 81,132 | $ (86,196) | $ (129,463) | $ (7,235) |
| **Net income (loss) per share:** | | | | | |
| Basic | $ 0.27 | $ 1.13 | $ (1.19) | $ (1.79) | $ (0.11) |
| Diluted | $ 0.25 | $ 0.87 | $ (1.19) | $ (1.79) | $ (0.11) |
| Weighted average shares outstanding, basic | 72,651 | 71,536 | 72,398 | 72,438 | 67,909 |
| Weighted average shares outstanding, diluted | 103,452 | 103,606 | 72,398 | 72,438 | 67,909 |

| | Three months ended September 30, | | Three months ended June 30, | Nine months ended September 30, | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2015 | 2014 |
| **Production** | | | | | |
| Crude oil (MBbls) | 1,205 | 1,247 | 1,280 | 3,822 | 3,442 |
| NGLs (MBbls) | 332 | 308 | 384 | 1,112 | 796 |
| Natural gas (MMcf) | 2,358 | 3,201 | 2,860 | 8,165 | 10,412 |
| **Total crude oil, NGL and natural gas production (MBOE)** | 1,930 | 2,089 | 2,140 | 6,295 | 5,973 |
| **Prices** | | | | | |
| Crude oil ($ per Bbl) | $ 42.42 | $ 95.19 | $ 55.22 | $ 47.35 | $ 97.72 |
| NGLs ($ per Bbl) | $ 9.81 | $ 31.76 | $ 13.53 | $ 12.45 | $ 34.18 |

| | | | | | |
|---|---|---|---|---|---|
| Natural gas ($ per Mcf) | $ 2.68 | $ 4.17 | $ 2.54 | $ 2.71 | $ 4.60 |
| **Prices - Adjusted for derivative settlements** | | | | | |
| Crude oil ($ per Bbl) | $ 69.19 | $ 89.08 | $ 82.44 | $ 74.54 | $ 93.08 |
| NGLs ($ per Bbl) | $ 9.81 | $ 31.76 | $ 13.53 | $ 12.45 | $ 34.18 |
| Natural gas ($ per Mcf) | $ 2.68 | $ 4.19 | $ 2.54 | $ 2.80 | $ 4.42 |

(a) We have reclassified approximately $0.5 million and $1.2 million of certain natural gas compression costs from lease operating expense to gathering, processing and transportation expenses for the three and nine months ended September 30, 2014.

(b) Includes liability-classified share-based compensation expense (credit) of $(0.9) million and $(0.4) million for the three months ended September 30, 2015 and 2014 and $(0.7) million and $6.6 million for the nine months ended September 30, 2015 and 2014, respectively, attributable to our performance-based restricted stock units. The three months ended June 30, 2015 includes $(0.2) million attributable to these awards. The awards are payable in cash upon the achievement of certain market-based performance metrics. Also includes professional fees and other costs of approximately $0.7 million and $1.2 million for the three and nine months ended September 30, 2015 associated with our ongoing efforts to pursue strategic and/or refinancing transactions. We incurred approximately $0.4 million of these costs during the three months ended June 30, 2015.

(c) Our equity-classified share-based compensation expense includes non-cash charges for our stock option expense and the amortization of common, deferred and restricted stock and restricted stock unit awards related to equity-classified employee and director compensation in accordance with accounting guidance for share-based payments.

(d) We suspended our preferred stock dividends for the three months ended September 30, 2015; however, the dividends accumulate and are presented in the determination of net income (loss) attributable to common shareholders and earnings (loss) per share.

**PENN VIRGINIA CORPORATION**

**CONDENSED CONSOLIDATED BALANCE SHEETS - unaudited**

(in thousands)

| | As of | |
|---|---|---|
| | September 30, 2015 | December 31, 2014 |
| **Assets** | | |
| Current assets | $ 179,875 | $ 335,027 |
| Net property and equipment | 1,818,586 | 1,825,098 |
| Other assets | 21,985 | 41,738 |
| Total assets | $ 2,020,446 | $ 2,201,863 |
| **Liabilities and shareholders' equity** | | |
| Current liabilities | $ 161,908 | $ 312,227 |
| Revolving credit facility | 140,000 | 35,000 |
| Senior notes due 2019 | 300,000 | 300,000 |
| Senior notes due 2020 | 775,000 | 775,000 |
| Debt issuance costs | (21,638) | (24,571) |
| Other liabilities and deferred income taxes | 110,105 | 128,390 |
| Total shareholders' equity | 555,071 | 675,817 |
| Total liabilities and shareholders' equity | $ 2,020,446 | $ 2,201,863 |

**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - unaudited**

(in thousands)

| | Three months ended September 30, | | Three months ended June 30, | Nine months ended September 30, | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2015 | 2014 |
| **Cash flows from operating activities** | | | | | |
| Net income (loss) | $ 25,900 | $ 89,661 | $ (80,129) | $ (111,394) | $ 8,102 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | | | |
| Depreciation, depletion and amortization | 76,850 | 71,999 | 85,416 | 253,056 | 215,623 |
| Impairments | -- | 6,084 | 1,084 | 1,084 | 123,992 |

| | | | | | |
|---|---|---|---|---|---|
| Accretion of firm transportation obligation | 260 | 407 | 233 | 705 | 991 |
| Derivative contracts: | | | | | |
| Net losses (gains) | (44,701) | (66,457) | 15,495 | (52,073) | (8,130) |
| Cash settlements, net | 32,258 | (7,557) | 34,840 | 104,590 | (17,836) |
| Deferred income tax expense (benefit) | 36 | 42,113 | 89 | 266 | (339) |
| (Gain) loss on sales of assets, net | (50,828) | (63,520) | (66) | (50,803) | (120,295) |
| Non-cash exploration expense | 898 | 1,808 | 2,022 | 4,903 | 8,387 |
| Non-cash interest expense | 1,224 | 1,063 | 1,176 | 3,504 | 3,114 |
| Share-based compensation (equity-classified) | 1,263 | 987 | 1,116 | 3,369 | 2,638 |
| Other, net | (20) | 44 | (6) | (17) | 325 |
| Changes in operating assets and liabilities | 20,820 | 24,625 | (8,541) | 5,051 | (16,122) |
| Net cash provided by operating activities | 63,960 | 101,257 | 52,729 | 162,241 | 200,450 |
| **Cash flows from investing activities** | | | | | |
| Receipts (payments) to settle obligations assumed in acquisition, net | -- | 33,712 | -- | -- | 33,712 |
| Capital expenditures - property and equipment | (60,883) | (194,451) | (94,999) | (324,876) | (545,031) |
| Proceeds from sales of assets, net | 73,891 | 215,281 | (337) | 73,670 | 311,913 |
| Net cash provided by (used in) investing activities | 13,008 | 54,542 | (95,336) | (251,206) | (199,406) |
| **Cash flows from financing activities** | | | | | |
| Proceeds from the issuance of preferred stock, net | -- | (316) | -- | -- | 313,330 |
| Payments made to induce conversion of preferred stock | -- | (888) | -- | -- | (4,256) |
| Proceeds from revolving credit facility borrowings | 6,000 | 75,000 | 70,000 | 203,000 | 377,000 |
| Repayment of revolving credit facility borrowings | (78,000) | (130,000) | (20,000) | (98,000) | (583,000) |
| Debt issuance costs paid | -- | -- | (744) | (744) | (151) |
| Dividends paid on preferred and common stock | (6,067) | (1,329) | (6,067) | (18,201) | (5,165) |
| Other, net | -- | 329 | -- | -- | 1,414 |
| Net cash (used in) provided by financing activities | (78,067) | (57,204) | 43,189 | 86,055 | 99,172 |
| Net increase (decrease) in cash and cash equivalents | (1,099) | 98,595 | 582 | (2,910) | 100,216 |
| Cash and cash equivalents - beginning of period | 4,441 | 25,095 | 3,859 | 6,252 | 23,474 |
| Cash and cash equivalents - end of period | $ 3,342 | $ 123,690 | $ 4,441 | $ 3,342 | $ 123,690 |

**PENN VIRGINIA CORPORATION**

**CERTAIN NON-GAAP FINANCIAL MEASURES - unaudited**

(in thousands)

| | Three months ended September 30, | | Three months ended June 30, | Nine months ended September 30, | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2015 | 2014 |
| **Reconciliation of GAAP "Net income (loss) " to Non-GAAP "Net income (loss) applicable to common shareholders, as adjusted"** | | | | | |
| Net income (loss) | $ 25,900 | $ 89,661 | $ (80,129) | $ (111,394) | $ 8,102 |
| Adjustments for derivatives: | | | | | |
| Net losses (gains) | (44,701) | (66,457) | 15,495 | (52,073) | (8,130) |
| Cash settlements, net | 32,258 | (7,557) | 34,840 | 104,590 | (17,836) |
| Adjustment for impairments | -- | 6,084 | 1,084 | 1,084 | 123,992 |
| Adjustment for restructuring costs | 23 | 18 | 753 | 765 | 27 |
| Adjustment for refinancing and strategic transaction costs | 733 | -- | 416 | 1,195 | -- |
| Adjustment for rig termination charge | 517 | -- | 2,039 | 6,182 | -- |
| Adjustment for (gain) loss on sale of assets, net | (50,828) | (63,520) | (66) | (50,803) | (120,295) |
| Impact of adjustments on income taxes | (1,531) | 42,004 | 61 | (39) | (971) |
| Preferred stock dividends | (5,935) | (7,641) | (6,067) | (18,069) | (11,081) |
| **Net loss applicable to common shareholders, as adjusted (a)** | $ (43,564) | $ (7,408) | $ (31,574) | $ (118,562) | $ (26,192) |
| **Net loss applicable to common shareholders, as adjusted, per share, diluted** | $ (0.60) | $ (0.10) | $ (0.44) | $ (1.64) | $ (0.39) |

**Reconciliation of GAAP "Net income (loss)" to Non-GAAP "Adjusted EBITDAX"**

| | | | | | |
|---|---|---|---|---|---|
| Net income (loss) | $ 25,900 | $ 89,661 | $ (80,129) | $ (111,394) | $ 8,102 |
| Income tax benefit | (624) | 42,113 | 89 | (394) | (339) |
| Interest expense | 22,985 | 21,953 | 23,023 | 68,021 | 67,716 |
| Depreciation, depletion and amortization | 76,850 | 71,999 | 85,416 | 253,056 | 215,623 |
| Exploration | 1,673 | 1,986 | 4,362 | 11,922 | 13,995 |
| Share-based compensation expense (equity-classified awards) | 1,263 | 987 | 1,116 | 3,369 | 2,638 |
| **EBITDAX** | 128,047 | 228,699 | 33,877 | 224,580 | 307,735 |
| Adjustments for derivatives: | | | | | |
| Net losses (gains) | (44,701) | (66,457) | 15,495 | (52,073) | (8,130) |
| Cash settlements, net | 32,258 | (7,557) | 34,840 | 104,590 | (17,836) |
| Adjustment for impairments | -- | 6,084 | 1,084 | 1,084 | 123,992 |
| Adjustment for (gain) loss on sale of assets, net | (50,828) | (63,520) | (66) | (50,803) | (120,295) |
| Adjustment for other non-cash items | 260 | 407 | 233 | 705 | 991 |
| **Adjusted EBITDAX (b)** | $ 65,036 | $ 97,656 | $ 85,463 | $ 228,083 | $ 286,457 |

(a) Net income (loss) applicable to common shareholders, as adjusted, represents net income (loss), less preferred stock dividends, adjusted to exclude the effects, net of income taxes, of non-cash changes in the fair value of derivatives, impairments, restructuring costs, refinancing and strategic transaction, costs, rig termination charges and net gains and losses on the sale of assets. We believe this presentation is commonly used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of companies within the oil and gas exploration and production industry. We use this information for comparative purposes within our industry. Net income (loss) applicable to common shareholders, as adjusted, is not a measure of financial performance under GAAP and should not be considered as a measure of liquidity or as an alternative to net loss applicable to common shareholders.

(b) Adjusted EBITDAX represents net income (loss) before income taxes, interest expense, depreciation, depletion and amortization expense, exploration expense and share-based compensation expense, further adjusted to exclude the effects of non-cash changes in the fair value of derivatives, impairments, net gains and losses on the sale of assets and other non-cash items. We believe this presentation is commonly used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of companies within the oil and gas exploration and production industry. We use this information for comparative purposes within our industry. Adjusted EBITDAX is not a measure of financial performance under GAAP and should not be considered as a measure of liquidity or as an alternative to net income (loss).

**PENN VIRGINIA CORPORATION**

**GUIDANCE TABLE - unaudited**

(dollars in millions except where noted)

We are providing the following guidance regarding financial and operational expectations for 2015.

These estimates are meant to provide guidance only and are subject to change as PVA's operating environment changes.

| | Actual Results | | | | | 2015 Guidance | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Fourth Quarter 2014 | First Quarter 2015 | Second Quarter 2015 | Third Quarter 2015 | Year-to-Date 2015 | Fourth Quarter | | Full-Year | |
| Production: | | | | | | | | | |
| Crude oil (MBbls) | 1,202 | 1,337 | 1,280 | 1,205 | 3,822 | 1,000 - | 1,100 | 4,822 - | 4,922 |
| NGLs (MBbls) | 314 | 397 | 384 | 332 | 1,112 | 240 - | 280 | 1,352 - | 1,392 |
| Natural gas (MMcf) | 2,672 | 2,947 | 2,860 | 2,358 | 8,165 | 1,500 - | 1,700 | 9,665 - | 9,865 |
| Equivalent production (MBOE) | 1,961 | 2,225 | 2,140 | 1,930 | 6,295 | 1,490 - | 1,663 | 7,785 - | 7,958 |
| Equivalent daily production (BOEPD) | 21,314 | 24,721 | 23,519 | 20,976 | 23,058 | 16,196 - | 18,080 | 21,328 - | 21,803 |
| | | | | | | | | | |
| Production revenues (a): | | | | | | | | | |
| Crude oil | $ 83.9 | 59.2 | 70.7 | 51.1 | 181.0 | 42.0 - | 45.0 | 223.0 - | 226.0 |
| NGLs | $ 7.4 | 5.4 | 5.2 | 3.3 | 13.8 | 2.0 - | 2.5 | 15.8 - | 16.3 |
| Natural gas | $ 10.2 | 8.6 | 7.3 | 6.3 | 22.1 | 3.5 - | 4.5 | 25.6 - | 26.6 |
| Total product revenues | $ 101.4 | 73.1 | 83.1 | 60.7 | 216.9 | 47.5 - | 52.0 | 264.4 - | 268.9 |
| Crude oil derivative receipts (payments) | $ 9.8 | 36.8 | 34.8 | 32.3 | 103.9 | 30.0 - | 30.5 | 133.9 - | 134.4 |
| Natural gas derivative receipts (payments) | $ 0.6 | 0.7 | 0.0 | 0.0 | 0.7 | 0.0 - | 0.0 | 0.7 - | 0.7 |
| Total product revenues (including derivatives) | $ 111.8 | 110.6 | 118.0 | 93.0 | 321.5 | 77.5 - | 82.5 | 399.0 - | 404.0 |
| | | | | | | | | | |
| Operating expenses: | | | | | | | | | |
| Lease operating | $ 11.4 | 11.6 | 10.9 | 11.3 | 33.8 | 8.6 - | 9.2 | 42.4 - | 43.0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Lease operating ($ per BOE) | $ 5.82 | 5.20 | 5.10 | 5.86 | 5.37 | 5.45 - | 5.84 | 5.38 - | 5.46 |
| Gathering, processing and transportation costs | $ 5.7 | 7.5 | 6.4 | 5.7 | 19.5 | 3.7 - | 4.0 | 23.2 - | 23.5 |
| Gathering, processing and transportation costs ($ per BOE) | $ 2.90 | 3.37 | 2.98 | 2.93 | 3.10 | 2.35 - | 2.54 | 2.95 - | 2.99 |
| Production and ad valorem taxes | $ 5.5 | 4.7 | 5.0 | 3.5 | 13.1 | 2.7 - | 2.9 | 15.8 - | 16.0 |
| Production and ad valorem taxes (percent of product revenues) | 5.4% | 6.4% | 6.0% | 5.7% | 6.1% | 5.4% - | 5.8% | 5.9% - | 6.0% |
| General and administrative: | | | | | | | | | |
| Recurring general and administrative | $ 7.1 | 10.6 | 9.4 | 8.2 | 28.2 | 8.0 - | 9.0 | 36.2 - | 37.2 |
| Non-recurring general and administrative | $ (0.0) | 0.0 | 1.2 | 0.8 | 2.0 | 0.0 - | 0.5 | 2.0 - | 2.5 |
| Share-based compensation | $ (1.1) | 1.4 | 0.9 | 0.4 | 2.7 | 1.1 - | 1.1 | 3.8 - | 3.8 |
| Total reported G&A | $ 6.0 | 12.0 | 11.5 | 9.4 | 32.9 | 9.1 - | 10.6 | 42.0 - | 43.5 |
| Exploration: | | | | | | | | | |
| Total reported exploration | $ 3.1 | 5.9 | 4.4 | 1.7 | 11.9 | 0.5 - | 1.0 | 12.4 - | 12.9 |
| Drilling rig termination charges | $ 0.0 | 3.6 | 2.0 | 0.5 | 6.2 | 0.5 - | 1.0 | 6.7 - | 7.2 |
| Unproved property amortization | $ 1.9 | 2.0 | 2.0 | 0.9 | 4.9 | 0.0 - | 1.0 | 4.9 - | 5.9 |
| Depreciation, depletion and amortization | $ 84.7 | 90.8 | 85.4 | 76.9 | 253.1 | 63.0 - | 64.0 | 316.1 - | 317.1 |
| Depreciation, depletion and amortization ($ per BOE) | $ 43.18 | 40.81 | 39.91 | 39.82 | 40.20 | 39.96 - | 40.59 | 40.15 - | 40.28 |
| Adjusted EBITDAX (b) | $ 84.8 | 77.6 | 85.5 | 65.0 | 228.1 | 52.0 - | 56.0 | 280.1 - | 284.1 |
| Capital expenditures: | | | | | | | | | |
| Drilling and completion | $ 229.2 | 134.1 | 88.1 | 39.9 | 262.1 | 34.0 - | 39.5 | 296.1 - | 301.6 |
| Lease acquisitions | $ (1.5) | 8.8 | 5.3 | (0.5) | 13.6 | 0.5 - | 2.0 | 14.1 - | 15.6 |
| Seismic (c) | $ 0.3 | 0.3 | 0.3 | 0.3 | 0.8 | 0.0 - | 0.0 | 0.8 - | 0.8 |
| Pipeline, gathering, facilities and other | $ 9.1 | 3.3 | 0.7 | 0.2 | 4.2 | 1.0 - | 2.0 | 5.2 - | 6.2 |
| Total capital expenditures | $ 237.1 | 146.5 | 94.4 | 39.8 | 280.7 | 35.5 - | 43.5 | 316.2 - | 324.2 |
| End of period debt outstanding | $ 1,110.0 | 1,237.0 | 1,287.0 | 1,215.0 | 1,215.0 | 1,230.0 - | 1,245.0 | 1,230.0 - | 1,245.0 |
| Interest expense: | | | | | | | | | |
| Total reported interest expense | $ 21.1 | 22.0 | 23.0 | 23.0 | 68.0 | 24.0 - | 24.3 | 92.0 - | 92.3 |
| Cash interest expense | $ 20.0 | 20.9 | 21.8 | 21.8 | 64.5 | 23.0 - | 23.7 | 87.5 - | 88.2 |
| Preferred stock dividends paid | $ 7.6 | 6.1 | 6.1 | 6.1 | 18.2 | 0.0 - | 0.0 | 18.2 - | 18.2 |
| Effective tax rate | 23.9% | -0.2% | -0.1% | -2.5% | 0.4% | | | | |

(a) Assumes average benchmark prices of $44.93 per barrel for crude oil and $2.56 per MMBtu for natural gas in the fourth quarter of 2015, prior to any premium or discount for quality, basin differentials, the impact of hedges and other adjustments. NGL realized pricing is assumed to be $8.55 per barrel in the fourth quarter of 2015, or approximately 19% of the benchmark crude oil price.

(b) Adjusted EBITDAX is not a measure of financial performance under GAAP and should not be considered as a measure of liquidity or as an alternative to net income.

(c) Seismic expenditures are also reported as a component of exploration expense and as a component of net cash provided by operating activities.

**PENN VIRGINIA CORPORATION**

**GUIDANCE TABLE - unaudited - (continued)**

**Note to Guidance Table:**

The following table shows our current derivative positions.

| | | | Weighted Average Price | |
|---|---|---|---|---|
| | **Instrument Type** | **Average Volume Per Day** | **Floor/ Swap / Option** | **Ceiling** |
| **Crude oil:** | | **(barrels)** | **($ / barrel)** | |
| Bitmap Bitmap Fourth quarter 2015 | Collars | 3,000 | 86.67 | 94.73 |
| Fourth quarter 2015 | Swaps | 8,000 | 91.06 | |

| | | | |
|---|---|---|---|
| Fourth quarter 2015 | Sold Puts (a) | 5,000 | 70.00 |
| First quarter 2016 | Swaps | 6,000 | 80.41 |
| Second quarter 2016 | Swaps | 6,000 | 80.41 |
| Third quarter 2016 | Swaps | 6,000 | 80.41 |
| Fourth quarter 2016 | Swaps | 6,000 | 80.41 |

(a) These "lower" puts were sold at a strike price of $70 per barrel. If the price of WTI oil goes below $70 per barrel, the cash receipts on other 2015 derivatives will be limited to the difference between the swap / floor price and $70 per barrel.

We estimate that, excluding the derivative positions described above, for every $10.00 per barrel increase or decrease in the crude oil price, operating income for the fourth quarter of 2015 would increase or decrease by approximately $9.1 million. In addition, we estimate that, excluding the derivative positions described above, for every $1.00 per MMBtu increase or decrease in the natural gas price, operating income for the fourth quarter of 2015 would increase or decrease by approximately $1.5 million. This assumes that crude oil prices, natural gas prices and inlet volumes remain constant at anticipated levels. These estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

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PENN VIRGINIA CORPORATION

Source: Penn Virginia Corporation