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FOR IMMEDIATE RELEASE

PENN VIRGINIA CORPORATION ANNOUNCES SECOND QUARTER 2015 RESULTS AND PROVIDES UPDATES OF 2015 GUIDANCE AND OPERATIONS

RADNOR, PA (Globe Newswire) July 29, 2015 – Penn Virginia Corporation (NYSE: PVA) today reported financial results for the three months ended June 30, 2015 and provided updates of its operations and 2015 capital plan and guidance.

Key Highlights

Second quarter 2015 results compared, as applicable, to first quarter 2015 results were as follows:

- Product revenues increased to $118.0 million from $110.6 million, including oil and gas derivatives.
  - Realized oil, gas and natural gas liquids (NGLs) prices were $82.44 per barrel, $2.54 per thousand cubic feet (Mcf) and $13.53 per barrel, compared to $71.79 per barrel, $3.14 per Mcf and $13.60 per barrel, including oil and gas derivatives.
- Unit production costs, including lease operating expense, gathering, processing and transportation expenses and production and ad valorem taxes, decreased to $10.40 per barrel of oil equivalent (BOE) from $10.68 per BOE.
- Recurring unit production and general and administrative (G&A) costs decreased 4% to $4.59 per BOE from $4.77 per BOE and were 23% lower than $5.98 per BOE in the second quarter of 2014.
- Adjusted EBITDAX, a non-GAAP (generally accepted accounting principles) measure, increased to $85.5 million, from $77.6 million.
- Total production during the second quarter was in excess of 2.1 million barrels of oil equivalent (MMBOE), or 23,519 BOE per day (BOEPD), compared to 24,721 BOEPD.
  - Total production increased 8% over the second quarter of 2014 and increased 18%, pro forma to exclude volumes from Mississippi properties sold in July 2014.
  - Eagle Ford production was 20,259 BOEPD, compared to 21,390 BOEPD.
  - The sequential decline in Eagle Ford production was due to high line pressure in sections of our midstream gathering system and lower than expected early-time production performance of our recent Upper Eagle Ford program
    - The estimated negative effect on production of high line pressure was approximately 500 BOEPD.
- Gross per well drilling and completion costs in the Eagle Ford, including facilities, averaged $6.9 million during the second quarter of 2015, $1.7 million, or approximately 19%, lower than the $8.6 million average cost during the first quarter of 2015. Drilling and completion costs are now approximately 30% less than what was experienced in the fourth quarter of 2014 and approximately 42% less than the third quarter of 2014.

Other recent highlights included:

- At June 30, 2015, our financial liquidity was $215 million and our leverage ratio was 3.7 times.
  - Assuming the closing of the previously announced sale of our East Texas assets, estimated to be in late August, our pro forma liquidity would be approximately $260 million.
  - Year-end 2015 liquidity is expected to be between $200 and $220 million, including the estimated borrowing base reduction due to the East Texas sale, but excludes any potential adjustment to our borrowing base in the fall of 2015.

- Preliminarily, we estimate 2016 capital expenditures to be between $200 and $250 million resulting in oil production during the fourth quarter of 2016 similar to that estimated for 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

H. Baird Whitehead, President and Chief Executive Officer stated, "Second quarter revenues and Adjusted EBITDAX were higher than we had expected, despite continued low product prices. We continue to focus on decreasing our costs with combined unit production and G&A costs declining approximately 4% from the first quarter. In addition, the execution of our drilling and completion program continues to improve with our overall per well costs now 30% and 42% lower than in the fourth and third quarters of 2014, respectively.

"Our second quarter production came in below the lower end of second quarter guidance, primarily for two reasons: first, higher gathering line pressures curtailed production by an estimated 500 BOEPD and, second, the early-time performance of our recent Upper Eagle Ford program did not meet our expectations. The line pressure issue will be resolved soon as our midstream transporter is adding additional compression and, as described more fully below, we have taken steps to improve our completion design which we believe will improve well performance. We remain confident in the potential of the Upper Eagle Ford on our acreage. Nevertheless, we will be focusing our drilling effort for the time being to two-string Lower Eagle Ford in Gonzales County and northwestern Lavaca County, where rates of returns are optimized. This redirection of our drilling program to Gonzales County, where the initial potentials (IPs) and drilling and completion costs are somewhat less, has led us to reduce both capital expenditures and production guidance for the second half of 2015, as detailed later in this release."

Mr. Whitehead concluded, "With the sale of East Texas, we have sufficient liquidity to execute the remainder of our 2015 program. Our focus now is developing a 2016 capital program relative to our expected liquidity such that, at the end of 2016, we will remain financially healthy."

Second Quarter 2015 Results

Overview of Results

Operating loss was $41.0 million in the second quarter of 2015, compared to operating loss of $57.9 million in the first quarter of 2015. This $16.9 million improvement was due to a $9.1 million increase in product and other revenues and a $7.8 million decrease in operating expenses.

Net loss attributable to common shareholders for the second quarter was $86.2 million, or $1.19 per diluted share, compared to net loss of $63.2 million, or $0.88 per diluted share, in the prior quarter. The primary reason for the decrease was the non-cash $38.4 million increase in derivatives expense, 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 $32.0 million, or $0.44 per diluted share, for the second quarter compared to a loss of $44.9 million, or $0.62 per diluted share, in the prior quarter. The primary reason for the improvement was the $16.9 million decrease in operating loss, partially offset by a $1.0 million increase in interest expense and a $2.7 million decrease in cash settlements of derivatives.

Production

As shown in the table below, total production in the second quarter of 2015 was 23,519 BOEPD, compared to 24,721 BOEPD in the first quarter of 2015, with a 1,131 BOEPD decrease in the Eagle Ford and a 71 BOEPD decrease in other areas. The decrease in production in the Eagle Ford, was primarily due to higher line pressure in sections of our gathering system, along with lower than expected early-time production performance from our recent Upper Eagle Ford drilling program.

Region / Play Type	Total and Daily Equivalent Production for the Three Months Ended					
	June 30, 2015	Mar. 31, 2015	June 30, 2014	June 30, 2015	Mar. 31, 2015	June 30, 2014
	(in MBOE)			(in BOEPD)		
Eagle Ford Shale	1,844	1,925	1,421	20,259	21,390	15,618
East Texas	173	173	220	1,898	1,925	2,417
Mid-Continent	119	121	161	1,302	1,345	1,770
Other	5	6	180	60	61	1,981
Totals	**2,140**	**2,225**	**1,983**	**23,519**	**24,721**	**21,786**
Pro Forma Totals[(1)]	**2,140**	**2,225**	**1,809**	**23,519**	**24,721**	**19,872**

Note - Numbers may not add due to rounding. MBOE equals one thousand barrels of oil equivalent.
(1) Pro forma to exclude volumes from Mississippi properties sold in July 2014 and the third quarter 2014 Mid-Continent adjustment.

Product Revenues

Total product revenues increased by $10.0 million, or 14%, to $83.1 million, or $38.84 per BOE, in the second quarter of 2015, from $73.1 million, or $32.87 per BOE, in the first quarter of 2015 due primarily to the 18% increase in the realized oil equivalent price, partially offset by a 4% decrease in daily production. Including derivatives, total product revenues were $118.0 million, or $55.12 per BOE, in the second quarter of 2015, compared to $110.6 million, or $49.72 per BOE, in the first quarter of 2015. For the second quarter, the realized oil price increased by 25%, the realized natural gas price decreased by 13% and the realized NGL price decreased by 1% compared to the first quarter of 2015.

Operating Expenses

As discussed below, second quarter 2015 total direct operating expenses, excluding share-based compensation and non-recurring expenses, decreased by $2.3 million to $32.1 million, or $14.99 per BOE produced, from $34.4 million, or $15.45 per BOE produced, in the first quarter of 2015.

- Lease operating expense decreased by $0.7 million to $10.9 million, or $5.10 per BOE, from $11.6 million, or $5.20 per BOE, due to lower volume-based costs, partially offset by higher workover costs.
- Gathering, processing and transportation expense decreased by $1.1 million to $6.4 million, or $2.98 per BOE, from $7.5 million, or $3.37 per BOE, due primarily to lower production volumes.
- Production and ad valorem taxes increased by $0.3 million to $5.0 million, or 6.0% of product revenues, from $4.7 million, or 6.4% of product revenues, due to higher oil prices.
- Recurring G&A expense decreased by $0.8 million to $9.8 million, or $4.59 per BOE, from $10.6 million, or $4.77 per BOE. The decrease in recurring G&A expense was due to lower salary and benefits costs associated with reduced headcount, partially offset by higher third party consulting costs.

Depletion, depreciation and amortization expense in the second quarter of 2015 decreased by $5.4 million to $85.4 million, or $39.91 per BOE, from $90.8 million, or $40.81 per BOE, in the first quarter.

We recorded an impairment charge of $1.1 million during the second quarter, attributable to tubular inventory and well materials.

Capital Expenditures

During the second quarter of 2015, capital expenditures were $94 million, a decrease of $53 million, or 36%, compared to $147 million in the first quarter of 2015, consisting of:

- $88 million for drilling and completion activities, compared to $134 million.
- $6 million for pipeline, gathering, facilities, seismic, leasehold acquisition and other capital expenditures, compared to $13 million.

Capital Resources and Liquidity, Interest Expense and Impact of Derivatives

As of June 30, 2015, we had total debt of $1,287 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 $212 million drawn under our revolving credit facility (Revolver). Together with cash and equivalents of $4 million and net of letters of credit of $2 million, our financial liquidity was $215 million at June 30, 2015. Pro forma liquidity, assuming the closing of the previously announced sale of our East Texas assets would have been $260 million, assuming a $30 million decrease to our borrowing base related to the assets to be divested.

Our total debt leverage ratio under the Revolver at June 30, 2015 was 3.7 times trailing twelve months' Adjusted EBITDAX of $355 million. The maximum leverage ratio allowable during the second 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 June 30, 2015, this ratio was 0.6 times. Pro forma total debt and credit exposure ratios, assuming the closing of the previously announced sale of our East Texas assets, were 3.6 times and 0.4 times, respectively.

During the second quarter, interest expense was $23.0 million, of which $21.8 million was cash interest expense, compared to $22.0 million, of which $20.9 million was cash interest expense in the first quarter. In addition, during the second quarter, we paid $6.1 million in preferred stock dividends, unchanged from the first quarter.

During the second quarter, derivatives expense was $15.5 million, compared to derivatives income of $22.9 million in the first quarter. Second quarter cash settlements of derivatives resulted in net cash receipts of $34.8 million, compared to $37.5 million of net cash receipts in the first quarter.

Derivatives Update
To support our operating cash flows, we hedge a portion of our oil and natural gas production at pre-determined prices or price ranges. Currently, we have hedged 11,000 barrels of daily crude oil production during the second half of 2015, or about 80% to 90% 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 second half 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 hedges.

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 20,700 to 22,600 BOEPD, compared to previous guidance of 23,800 to 26,200 BOEPD, including the impact of the pending sale of East Texas assets, which we assume closes on August 31st.
  - 2015 crude oil production of 13,050 to 14,350 barrels of oil per day (BOPD), compared to previous guidance of 14,000 to 15,400 BOPD.
  - Production in the third and fourth quarters of 2015 is expected to range between 18,500 and 22,800 BOEPD and 16,300 and 19,600 BOEPD, respectively, including the impact of the pending sale of East Texas assets.
- Product revenues, excluding the impact of any hedges, are expected to be $284 to $307 million, compared to previous guidance of $320 to $350 million.
  - Our crude oil revenue estimate assumes realized pricing of West Texas Intermediate (WTI) crude oil benchmark pricing of $55.00 per barrel. Benchmark (Henry Hub) natural gas pricing is assumed to be $2.88 per Mcf ($2.75 per Mcf in the third quarter and $3.00 per Mcf in the fourth quarter), while NGL pricing is assumed to be 16% of the WTI price.
  - Cash receipts from the settlement of derivatives are expected to be $127 million, based on the foregoing assumptions, up compared to the midpoint of previous guidance of $121 million.
- Adjusted EBITDAX, a non-GAAP measure, is expected to be $285 to $310 million, compared to previous guidance of $300 to $340 million.
  - Net cash provided by operating activities, including expected working capital changes, is expected to be $147 to $156 million, compared to previous guidance of $165 to $185 million.
- Capital expenditures are expected to be $325 to $345 million, compared to previous guidance of $325 to $370 million.
  - Drilling and completion capital expenditures are expected to be $305 to $320 million, compared to previous guidance of $310 to $350 million.
  - Pipeline, gathering, facilities, seismic and other capital expenditures are expected to be $5 to $8 million, compared to previous guidance of $5 to $7 million.

- Lease acquisition capital expenditures are expected to be $14 to $15 million, compared to previous guidance of $10 to $11 million.

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

Preliminarily, and based on expected conditions in the crude oil market, specifically $55 to $60 per barrel WTI crude oil pricing, we expect to spend $200 to $250 million in capital expenditures during 2016, with fourth quarter 2016 oil production up to approximately 10% higher than the midpoint of fourth quarter 2015 oil production guidance. 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 our operating environment changes.

Eagle Ford Shale Operational Update

Second Quarter 2015 Update

Second quarter production from our Eagle Ford operations was 20,259 BOEPD, a 5% decrease from the 21,390 BOEPD produced in the first quarter of 2015. Approximately 68% of our second quarter Eagle Ford production was from crude oil, 17% was from NGLs and 15% was from natural gas, unchanged from the first quarter of 2015. As explained in this release, the decrease was primarily attributable to higher line pressure in sections of our midstream gathering systems and lower than expected early-time performance of Upper Eagle Ford wells during the second quarter.

Well Cost Reductions

Average gross well costs for all wells drilled and completed during the second quarter of 2015 declined by approximately $1.7 million, or 19%, to $6.9 million from approximately $8.6 million for wells drilled and completed in the first quarter of 2015. This lower overall well cost equates to approximately a 30% and 42% decrease in well costs since the fourth quarter and third quarters of 2014, respectively. More specifically, the cost of our most recent two-string Lower Eagle Ford wells averaged $5.3 million, while our most recent three-string wells averaged $8.0 million.

Average drilling costs for the second quarter of 2015 decreased 24% and 30% compared to the fourth and third quarters of 2014, respectively, driven by enhanced efficiencies and increased average rates of penetration. Average completion costs for wells over those same time intervals declined by 34% and 51%, respectively. Approximately half of the decreases in completion costs can be attributed to ongoing optimization and increased efficiencies, while the other half can be attributed to improved pricing.

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 - 2nd quarter	21 / 12.5	5,487	25.2	9,218,820	1,191	1,472	81%	736	903	83%
2014 - 3rd quarter	23 / 12.2	5,756	27.0	10,038,484	1,079	1,268	85%	676	788	86%
2014 - 4th quarter	19 / 14.9	5,536	25.8	10,222,539	832	1,230	68%	618	910	69%
2015 - 1st quarter	28 / 15.3	6,184	27.0	8,236,324	1,060	1,269	84%	684	809	86%
2015 – 2nd quarter[4]	20 / 14.8	5,897	24.0	6,930,019	623	823	79%	456	596	76%
Totals and averages[4]	**111/69.7**	**5,801**	**25.9**	**8,900,235**	**971**	**1,220**	**80%**	**654**	**817**	**81%**
Operating Area										
Upper Eagle Ford	31 / 25.7	5,968	26.0	8,821,497	645	1,031	67%	524	824	67%
Lavaca "Beer Area"	29 / 13.7	5,871	26.6	9,691,705	1,252	1,522	81%	764	911	83%
Rock Creek / Bozka	10 / 4.6	5,767	27.1	9,740,905	1,276	1,444	88%	913	1,030	89%
Peach Creek	11 / 5.5	5,149	24.6	9,121,632	1,083	1,179	92%	631	681	93%
Shiner	14 / 11.1	5,637	24.1	7,216,832	767	1,036	73%	504	667	75%
Shallow Gonzales	16 / 9.1	5,962	26.2	8,413,596	1,005	1,088	93%	638	683	94%
Totals and averages[4]	**111/69.7**	**5,801**	**25.9**	**8,900,235**	**971**	**1,220**	**80%**	**654**	**817**	**81%**

(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.
(4) 30-day information is available for 12 wells since the end of the first quarter of 2015 and for 104 wells since April 1, 2014. Second quarter 2015 average includes data for wells turned in line after June 30, 2015.

Since the end of the first quarter of 2015, we have turned in line 20 (14.8 net) operated wells. As a group, these 20 wells had an average IP rate of 823 BOEPD over an average of 24.0 frac stages, with 79% of production from crude oil. Ten of these wells were drilled into the Lower Eagle Ford and had an average IP rate of 1,027 BOEPD over and an average of 24.1 frac stages. The other ten of these wells were drilled into the Upper Eagle Ford and had an average IP rate of 618 BOEPD over and an average of 23.8 frac stages. Of these 20 wells, 12 wells with sufficient production history had a 30-day average rate of 596 BOEPD, with 76% of production from crude oil. The average amount of proppant per stage for these 20 wells was approximately 290,000 pounds and average amount of proppant per lateral foot was approximately 1,175 pounds, as discussed below.

Evolving Completion Design

Despite the disappointing IP rates of some of our recent Upper Eagle Ford wells, we continue to believe that the Upper Eagle Ford has significant potential across much of our acreage. Furthermore, we have identified certain factors which we believe contributed to our recent less-than-expected well results in the Upper Eagle Ford. First, in the first half of 2015, we reduced the amount of proppant pumped per foot of lateral. A detailed analysis has yielded evidence that there is a positive correlation between the amount of proppant pumped and well performance, so we intend to increase proppant in the third quarter. In addition, we have drilled some excellent Upper Eagle Ford wells in the general vicinity of other wells that had disappointing results, with the difference being that the better performing wells had alternating laterals in the Upper and Lower Eagle Ford that were then “zipper” fracked. Finally, we also intend to transition to “slickwater” stimulations. We believe that using this more complex completion technique of alternating laterals, increasing proppant pumped per stage and transitioning to slickwater stimulations in combination will improve our well results.

Drilling Program Outlook

For the remainder of 2015 and due primarily to continued low oil prices, we are discontinuing any Upper Eagle Ford drilling and are focusing our efforts drilling on less costly two-string Lower Eagle Ford wells in Gonzales County and northwestern Lavaca County where our economics are optimized. Preliminarily, we expect to resume multi-well pad drilling of alternating Upper and Lower Eagle Ford wells in 2016.

Second Quarter 2015 Conference Call

A conference call and webcast, during which management will discuss second quarter 2015 financial and operational results, is scheduled for Thursday, July 30, 2015 at 10:00 a.m. ET. Prepared remarks by H. Baird Whitehead, President and Chief Executive Officer, 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 59450442), 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 59450442. 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.

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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, 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; any impairments, write-downs or write-offs of our reserves or assets; the projected demand for and supply of oil, NGLs and natural gas; reductions in the borrowing base under our revolving credit facility, or the Revolver; 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; our ability to maintain adequate financial liquidity and to access adequate levels of capital on reasonable terms; compliance with debt covenants; 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.

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PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - unaudited
(in thousands, except per share data)

	Three months ended June 30, 2015	Three months ended June 30, 2014	Three months ended March 31, 2015	Six months ended June 30, 2015	Six months ended June 30, 2014
Revenues					
Crude oil	$ 70,672	$ 112,090	$ 59,168	$ 129,840	$ 217,666
Natural gas liquids (NGLs)	5,191	8,037	5,396	10,587	17,410
Natural gas	7,260	16,302	8,571	15,831	34,505
Total product revenues	83,123	136,429	73,135	156,258	269,581
Gain (loss) on sales of property and equipment, net	66	(51)	(91)	(25)	56,775
Other	427	2,983	1,483	1,910	2,870
Total revenues	83,616	139,361	74,527	158,143	329,226
Operating expenses					
Lease operating	10,907	12,001	11,569	22,476	22,117
Gathering, processing and transportation (a)	6,383	3,928	7,498	13,881	7,177
Production and ad valorem taxes	4,967	7,510	4,689	9,656	14,815
General and administrative (excluding equity-classified share-based compensation) (b)	10,363	14,014	10,980	21,343	29,877
Total direct operating expenses	32,620	37,453	34,736	67,356	73,986
Share-based compensation - equity classified awards (c)	1,116	826	990	2,106	1,651
Exploration	4,362	3,373	5,887	10,249	12,009
Depreciation, depletion and amortization	85,416	71,437	90,790	176,206	143,624
Impairments	1,084	117,908	-	1,084	117,908
Total operating expenses	124,598	230,997	132,403	257,001	349,178
Operating income (loss)	(40,982)	(91,636)	(57,876)	(98,858)	(19,952)
Other income (expense)					
Interest expense	(23,023)	(23,229)	(22,013)	(45,036)	(45,763)
Derivatives	(15,495)	(42,665)	22,867	7,372	(58,327)
Other	(540)	30	(2)	(542)	31
Income (loss) before income taxes	(80,040)	(157,500)	(57,024)	(137,064)	(124,011)
Income tax (expense) benefit	(89)	56,716	(141)	(230)	42,452
Net income (loss)	(80,129)	(100,784)	(57,165)	(137,294)	(81,559)
Preferred stock dividends	(6,067)	(1,718)	(6,067)	(12,134)	(3,440)
Induced conversion of preferred stock	-	(3,368)	-	-	(3,368)
Net income (loss) attributable to common shareholders	$ (86,196)	$ (105,870)	$ (63,232)	$ (149,428)	$ (88,367)
Net income (loss) per share:					
Basic	$ (1.19)	$ (1.59)	$ (0.88)	$ (2.07)	$ (1.34)
Diluted	$ (1.19)	$ (1.59)	$ (0.88)	$ (2.07)	$ (1.34)
Weighted average shares outstanding, basic	72,398	66,514	71,820	72,330	66,065
Weighted average shares outstanding, diluted	72,390	66,514	71,820	72,330	66,065

	Three months ended June 30, 2015	Three months ended June 30, 2014	Three months ended March 31, 2015	Six months ended June 30, 2015	Six months ended June 30, 2014
Production					
Crude oil (MBbls)	1,280	1,119	1,337	2,617	2,195
NGLs (MBbls)	384	261	397	781	488
Natural gas (MMcf)	2,860	3,618	2,947	5,806	7,211
Total crude oil, NGL and natural gas production (MBOE)	2,140	1,983	2,225	4,365	3,885
Prices					
Crude oil ($ per Bbl)	$ 55.22	$ 100.16	$ 44.26	$ 49.62	$ 99.16
NGLs ($ per Bbl)	$ 13.53	$ 30.85	$ 13.60	$ 13.56	$ 35.71
Natural gas ($ per Mcf)	$ 2.54	$ 4.51	$ 2.91	$ 2.73	$ 4.78
Prices - Adjusted for derivative settlements					
Crude oil ($ per Bbl)	$ 82.44	$ 94.72	$ 71.79	$ 77.00	$ 95.35
NGLs ($ per Bbl)	$ 13.53	$ 30.85	$ 13.60	$ 13.56	$ 35.71
Natural gas ($ per Mcf)	$ 2.54	$ 4.20	$ 3.14	$ 2.85	$ 4.51

(a) We have reclassified approximately $0.4 million and $0.7 million of certain natural gas compression costs from lease operating expense to gathering, processing and transportation expenses for the three and six months ended June 30, 2014.
(b) Includes liability-classified share-based compensation expense (credit) of $(0.2) million and $1.0 million for the three months ended June 30, 2015 and 2014 and $0.2 million and $7.0 million for the six months ended June 30, 2015 and 2014, respectively, attributable to our performance-based restricted stock units. The three months ended March 31, 2015 includes $0.4 million attributable to these awards. The awards are payable in cash upon the achievement of certain market-based performance metrics.
(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.

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS - unaudited
(in thousands)

	As of June 30, 2015	As of December 31, 2014
Assets		
Current assets	$ 197,830	$ 335,027
Net property and equipment	1,888,892	1,825,098
Other assets	25,868	41,738
Total assets	$ 2,112,590	$ 2,201,863
Liabilities and shareholders' equity		
Current liabilities	$ 197,889	$ 312,227
Revolving credit facility	212,000	35,000
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	775,000
Debt issuance costs	(22,637)	(24,571)
Other liabilities and deferred income taxes	122,420	128,390
Total shareholders' equity	527,918	675,817
Total liabilities and shareholders' equity	$ 2,112,590	$ 2,201,863

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - unaudited
(in thousands)

	Three months ended June 30, 2015	Three months ended June 30, 2014	Three months ended March 31, 2015	Six months ended June 30, 2015	Six months ended June 30, 2014
Cash flows from operating activities					
Net income (loss)	$ (80,129)	$ (100,784)	$ (57,165)	(137,294)	$ (81,559)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation, depletion and amortization	85,416	71,437	90,790	176,206	143,624
Impairments	1,084	117,908	-	1,084	117,908
Accretion of firm transportation obligation	233	230	212	445	584
Derivative contracts:					
Net losses (gains)	15,495	42,665	(22,867)	(7,372)	58,327
Cash settlements, net	34,840	(7,222)	37,492	72,332	(10,279)
Deferred income tax expense (benefit)	89	(56,516)	141	230	(42,452)
(Gain) loss on sales of assets, net	(66)	51	91	25	(56,775)
Non-cash exploration expense	2,022	3,285	1,983	4,005	6,579
Non-cash interest expense	1,176	1,039	1,104	2,280	2,051
Share-based compensation (equity-classified)	1,116	826	990	2,106	1,651
Other, net	(6)	75	9	3	281
Changes in operating assets and liabilities	(8,541)	(40,361)	(7,228)	(15,769)	(40,747)
Net cash provided by operating activities	52,729	32,633	45,552	98,281	99,193
Cash flows from investing activities					
Capital expenditures - property and equipment	(94,999)	(190,776)	(168,994)	(263,993)	(350,580)
Proceeds from sales of assets, net	(337)	668	116	(221)	96,632
Net cash used in investing activities	(95,336)	(190,108)	(168,878)	(264,214)	(253,948)
Cash flows from financing activities					
Proceeds from the issuance of preferred stock, net	-	313,646	-	-	313,646
Payments made to induce conversion of preferred stock	-	(3,368)	-	-	(3,368)
Proceeds from revolving credit facility borrowings	70,000	217,000	127,000	197,000	302,000
Repayment of revolving credit facility borrowings	(20,000)	(352,000)	-	(20,000)	(453,000)
Debt issuance costs paid	(744)	(151)	-	(744)	(151)
Dividends paid on preferred and common stock	(6,067)	(2,111)	(6,067)	(12,134)	(3,836)
Other, net	-	-	-	-	1,085
Net cash provided by financing activities	43,189	173,016	120,933	164,122	156,376
Net increase (decrease) in cash and cash equivalents	582	15,541	(2,393)	(1,811)	1,621
Cash and cash equivalents - beginning of period	3,859	9,554	6,252	6,252	23,474
Cash and cash equivalents - end of period	$ 4,441	$ 25,095	$ 3,859	4,441	$ 25,095

PENN VIRGINIA CORPORATION
CERTAIN NON-GAAP FINANCIAL MEASURES - unaudited
(in thousands)

	Three months ended June 30,		Three months ended March 31,	Six months ended June 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)	$ (80,129)	$ (100,784)	$ (57,165)	$ (137,294)	$ (81,559)
Adjustments for derivatives:					
Net losses (gains)	15,495	42,665	(22,867)	(7,372)	58,327
Cash settlements, net	34,840	(7,222)	37,492	72,332	(10,279)
Adjustment for impairments	1,084	117,908	-	1,084	117,908
Adjustment for restructuring costs	753	(3)	(11)	742	9
Adjustment for rig termination charges	2,039	-	3,626	5,665	-
Adjustment for (gain) loss on sale of assets, net	(66)	51	91	25	(56,775)
Impact of adjustments on income taxes	60	(55,239)	45	122	(37,378)
Preferred stock dividends	(6,067)	(1,718)	(6,067)	(12,134)	(3,440)
Net loss applicable to common shareholders, as adjusted (a)	$ (31,991)	$ (4,342)	$ (44,856)	$ (76,830)	$ (13,187)
Net loss applicable to common shareholders, as adjusted, per share, diluted	$ (0.44)	$ (0.07)	$ (0.62)	$ (1.06)	$ (0.20)
Reconciliation of GAAP "Net income (loss)" to Non-GAAP "Adjusted EBITDAX"					
Net income (loss)	$ (80,129)	$ (100,784)	$ (57,165)	$ (137,294)	$ (81,559)
Income tax benefit	89	(56,716)	141	230	(42,452)
Interest expense	23,023	23,229	22,013	45,036	45,763
Depreciation, depletion and amortization	85,416	71,437	90,790	176,206	143,624
Exploration	4,362	3,373	5,887	10,249	12,009
Share-based compensation expense (equity-classified awards)	1,116	826	990	2,106	1,651
EBITDAX	33,877	(58,635)	62,656	96,533	79,036
Adjustments for derivatives:					
Net losses (gains)	15,495	42,665	(22,867)	(7,372)	58,327
Cash settlements, net	34,840	(7,222)	37,492	72,332	(10,279)
Adjustment for impairments	1,084	117,908	-	1,084	117,908
Adjustment for (gain) loss on sale of assets, net	(66)	51	91	25	(56,775)
Adjustment for other non-cash items	233	230	212	445	584
Adjusted EBITDAX (b)	$ 85,463	$ 94,997	$ 77,584	$ 163,047	$ 188,801

(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, 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 ne loss applicable to common shareholders.

(b) Adjusted EBITDAX represents net income (loss) before income tax benefit, 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.
The guidance reflects the closing of the pending sale of East Texas assets during the third quarter of 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		Fourth Quarter		Full-Year	
Production:										
Crude oil (MBbls)		1,202	1,337	1,280	1,125 -	1,375	1,025 -	1,250	4,767 -	5,242
NGLs (MBbls)		314	397	384	275 -	325	225 -	250	1,281 -	1,356
Natural gas (MMcf)		2,672	2,947	2,860	1,800 -	2,400	1,500 -	1,800	9,106 -	10,006
Equivalent production (MBOE)		1,961	2,225	2,140	1,700 -	2,100	1,500 -	1,800	7,565 -	8,265
Equivalent daily production (BOEPD)		21,314	24,721	23,519	18,478 -	22,826	16,304 -	19,565	20,726 -	22,644
Production revenues (a):										
Crude oil	$	83.9	59.2	70.7	57.0 -	68.8	59.0 -	67.0	245.8 -	265.6
NGLs	$	7.4	5.4	5.2	2.0 -	3.5	1.5 -	3.0	14.1 -	17.1
Natural gas	$	10.2	8.6	7.3	5.0 -	7.0	3.6 -	5.6	24.4 -	28.4
Total product revenues	$	101.4	73.1	83.1	64.0 -	79.3	64.1 -	75.6	284.4 -	311.1
Crude oil derivative receipts (payments)	$	9.8	36.8	34.8	27.0 -	30.0	25.0 -	28.0	123.7 -	129.7
Natural gas derivative receipts (payments)	$	0.6	0.7	0.0	0.0 -	0.0	0.0 -	0.0	0.7 -	0.7
Total product revenues (including derivatives)	$	111.8	110.6	118.0	91.0 -	109.3	89.1 -	103.6	408.7 -	441.4
Operating expenses:										
Lease operating	$	11.4	11.6	10.9					42.5 -	43.5
Lease operating ($ per BOE)	$	5.82	5.20	5.10					5.14 -	5.75
Gathering, processing and transportation costs	$	5.7	7.5	6.4					24.9 -	25.9
Gathering, processing and transportation costs ($ per BOE)	$	2.90	3.37	2.98					3.01 -	3.42
Production and ad valorem taxes	$	5.5	4.7	5.0					18.2 -	18.7
Production and ad valorem taxes (percent of product revenues)		5.4%	6.4%	6.0%					5.8% -	6.6%
General and administrative:										
Recurring general and administrative	$	7.1	10.6	9.8					38.4 -	39.4
Non-recurring general and administrative	$	(0.0)	(0.0)	0.6					0.5 -	0.5
Share-based compensation	$	(1.1)	1.4	1.1					6.5 -	7.5
Total reported G&A	$	6.0	12.0	11.5					45.4 -	47.4
Exploration:										
Total reported exploration	$	3.1	5.9	4.4					13.1 -	13.6
Drilling rig termination charges	$	0.0	3.6	2.0					7.0 -	7.5
Unproved property amortization	$	1.9	2.0	2.0					5.4 -	5.9
Depreciation, depletion and amortization	$	84.7	90.8	85.4					315.0 -	320.0
Depreciation, depletion and amortization ($ per BOE)	$	43.18	40.81	39.91					38.11 -	42.30
Adjusted EBITDAX (b)	$	84.8	77.6	85.5	65.0 -	75.0	57.0 -	72.0	285.0 -	310.0
Capital expenditures:										
Drilling and completion	$	229.2	134.1	88.1					305.0 -	320.0
Lease acquisitions	$	(1.5)	8.8	5.3					14.0 -	15.0
Seismic (c)	$	0.3	0.3	0.3					1.0 -	2.0
Pipeline, gathering, facilities and other	$	9.1	3.3	0.7					5.0 -	8.0
Total capital expenditures	$	237.1	146.5	94.4	52.0 -	61.0	32.1 -	43.1	325.0 -	345.0
End of period debt outstanding	$	1,110.0	1,237.0	1,287.0	1,217.0 -	1,227.0	1,247.0 -	1,267.0	1,247.0 -	1,267.0
Interest expense:										
Total reported interest expense	$	21.1	22.0	23.0					99.5 -	101.5
Cash interest expense	$	20.0	20.9	21.8					94.8 -	97.3
Preferred stock dividends paid	$	7.6	6.1	6.1	6.1 -	6.1	6.1 -	6.1	24.3 -	24.3
Effective tax rate		23.9%	-0.2%	-0.1%						

(a) Assumes average benchmark prices of $55.00 per barrel for crude oil and $2.88 per MMBtu for natural gas in second half 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 $8.94 per barrel in the second half of 2015, or approximately 16% 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)**	
Third quarter 2015	Collars	3,000	86.67	94.73
Fourth quarter 2015	Collars	3,000	86.67	94.73
Third quarter 2015	Swaps	8,000	91.06	
Fourth quarter 2015	Swaps	8,000	91.06	
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	
Third quarter 2015	Sold Puts (a)	5,000	70.00	
Fourth quarter 2015	Sold Puts (a)	5,000	70.00	

(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 second half of 2015 would increase or decrease by approximately $18.7 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 second half of 2015 would increase or decrease by approximately $2.5 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.