Penn Virginia Corporation Announces Fourth Quarter and Full-Year 2013 Financial Results and Provides 2014 Guidance

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2014 OIL PRODUCTION GROWTH EXPECTED TO BE 66 TO 78 PERCENT
2013 ADJUSTED EBITDAX OF $342 MILLION AND FOURTH QUARTER ADJUSTED EBITDAX OF $84 MILLION
2014 ADJUSTED EBITDAX EXPECTED TO BE $440 TO $485 MILLION
PRO FORMA YEAR-END 2013 FINANCIAL LIQUIDITY OF APPROXIMATELY $340 MILLION
62 PERCENT OF 2014 OIL PRODUCTION GUIDANCE MIDPOINT HEDGED AT AVERAGE FLOOR/SWAP PRICE OF $93.55 PER BARREL

RADNOR, Pa., Feb. 19, 2014 (GLOBE NEWSWIRE) -- Penn Virginia Corp. (NYSE:PVA) today reported financial results for the three months and year ended December 31, 2013 and provided 2014 guidance.

Fourth Quarter 2013 Highlights

Fourth quarter 2013 financial results, as compared to third quarter 2013 results, were as follows:

- Product revenues from the sale of oil, natural gas liquids (NGLs) and natural gas were $117.1 million, or $63.58 per barrel of oil equivalent (BOE), compared to $121.6 million, or $67.33 per BOE.
  * While crude oil production increased seven percent, the realized crude oil price declined 10 percent.
- Oil and NGL revenues were $105.0 million, or 90 percent of product revenues, compared to $108.8 million, or 89 percent of product revenues.
- Operating margin, a non-GAAP (generally accepted accounting principles) measure, was $47.07 per BOE, compared to $50.86 per BOE.
- Operating income was $15.5 million, compared to operating income of $24.4 million, excluding $132.2 million of impairment expense.
- Adjusted EBITDAX, a non-GAAP measure, was $84.4 million, compared to $88.3 million.
- Net loss attributable to common shareholders (which includes our preferred stock dividend) was $4.1 million, or $0.06 per diluted share, compared to a loss of $100.6 million, or $1.54 per diluted share.
- Adjusted net loss attributable to common shareholders, a non-GAAP measure which includes our preferred stock dividend but excludes the effects of impairments and other costs and other gains or losses that affect comparability to other periods, was $6.7 million, or $0.10 per diluted share, compared to a loss of $1.5 million, or $0.02 per diluted share.
- In January 2014, we sold our Eagle Ford Shale natural gas gathering assets for a total price of $100 million, $94 million net to our working interest. Pro forma financial liquidity at December 31, 2013 was approximately $340 million.

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, "In the fourth quarter, our operating cash flows and margins remained strong. While our production during the fourth quarter was consistent with previous guidance, we had a number of wells brought on line later than anticipated and these wells did not contribute as much to the fourth quarter results as we had expected. In addition, our non-operated partner suspended its drilling program. In response, we have increased our operated drilling rig count to six rigs where we intend to remain during 2014, subject to market conditions. To help fund this additional operated rig and our capital program in general, we have, as previously announced, retained a financial advisor for the potential sale of our Mid-Continent and Mississippi properties. That process has commenced and we hope to be in a position to announce a transaction or transactions by the second quarter of 2014. We were also pleased to close our sale of Eagle Ford Shale gas gathering assets at the top end of our expected proceeds range.

"We expect 2014 oil production growth of between 66 and 78 percent compared to 2013. We continue to increase our core Eagle Ford Shale position through leasing at a cost of approximately $2,800 per net acre since early November. Our stated goal of 100,000 net acres in the Eagle Ford Shale remains intact and we remain confident this is achievable at attractive acquisition costs. As a result of and in conjunction with successful downspaced drilling, we have increased our estimated drilling inventory by about 26 percent from 895 just a few months ago to the current estimate of approximately 1,125 drilling locations.

"Not included in this estimate of drilling locations is the potential inventory of upper Eagle Ford Shale locations. We have just run production casing on our second upper Eagle Ford Shale test well (Welhausen #A2H) and expect to complete it and the adjacent lower Eagle Ford Shale well in late first quarter or early second quarter. The cumulative production from the first upper Eagle Ford Shale test well (Fojtik #1H) was about 85,000 BOE for the first 290 days, which was very positive considering the relatively fewer number of frac stages and the shorter lateral length of this well.

"During the fourth quarter, our well costs per stage decreased again, while our well productivity per stage increased as a result of pumping additional proppant and the continued use of multi-well pads and 'zipper fracs.' We will continue to implement advanced techniques to further optimize our well results and economics.

"2013 was a very successful year for the Company, not only with a meaningful Eagle Ford Shale acquisition that added a significant number of drilling locations, but also with a drilling program that has generated very attractive rates of return.

"Our balance sheet remains sound with approximately $340 million of pro forma financial liquidity at year-end 2013, reflecting the first quarter 2014 sale of our Eagle Ford Shale natural gas gathering assets for $94 million, net to our interest. We expect to fund our capital programs over the next three years with increasing operating cash flows, net proceeds from asset sales and borrowings under our revolver, with the ongoing goals of decreasing our leverage ratio and, therefore, increasing our liquidity over this same timeframe."

Full-Year 2013 Financial Results

For the year ended December 31, 2013, we had operating income of $40.2 million, which excluded impairment charges of $132.2 million, compared to a loss for the year ended December 31, 2012 of $25.3 million, which excluded impairment charges and a loss on firm transportation obligations of $121.8 million. Adjusted loss attributable to common shareholders, excluding the effects of changes in derivatives fair value, acquisition transaction expenses, impairments, restructuring costs and other gains or losses that affect comparability to the prior year period, and including the preferred stock dividend of $6.9 million, was $30.7 million, or $0.49 per diluted share, in 2013 compared to a loss of $36.6 million, or $0.76 per diluted share, in 2012. Loss attributable to common shareholders (which includes our preferred stock dividend) was $150.0 million, or $2.41 per diluted share, in 2013 compared to a loss of $106.3 million, or $2.22 per diluted share, in 2012. The $43.7 million increase in loss was due primarily to a $57.0 million increase in derivatives loss, a $26.0 million increase in loss on extinguishment of debt, a $19.5 million increase in interest expense and a $5.2 million increase in preferred stock dividends, partially offset by a $55.0 million decrease in operating loss. Total production increased by five percent in 2013, from 6.5 million barrels of oil equivalent (MMBOE) to 6.8 MMBOE, while crude oil production increased by 53 percent in 2013, from 2.3 million barrels to 3.4 million barrels. Natural gas production declined by 29 percent from 20.3 billion cubic feet (Bcf) to 14.4 Bcf, due primarily to the sale of our Appalachian properties in mid-2012, along with the natural declines of our natural gas assets.

Fourth Quarter 2013 Results

Overview of Financial Results

The $15.5 million of operating income in the fourth quarter of 2013 was $8.9 million lower than $24.4 million in the third quarter of 2013, excluding $132.2 million of impairment expense. This decrease was due primarily to a $4.8 million increase in depreciation, depletion and amortization (DD&A) expense, a $4.5 million decrease in product revenues, a $2.1 million increase in lease operating expense and a $1.5 million increase in share-based and liability-based compensation expenses. The effect of these changes was partially offset by a $3.7 million decrease in production taxes and a $1.1 million decrease in exploration expense.

Pricing

Our fourth quarter 2013 realized oil price was $94.66 per barrel, compared to $105.37 per barrel in the third quarter of 2013. Our fourth quarter 2013 realized NGL price was $34.56 per barrel, compared to $32.34 per barrel in the third quarter. Our fourth quarter 2013 realized natural gas price was $3.45 per thousand cubic feet (Mcf), compared to $3.58 per Mcf in the third quarter. Adjusting for oil and gas hedges, our fourth quarter 2013 effective oil price was $91.48 per barrel and our fourth quarter 2013 effective natural gas price was $3.61 per Mcf, or a decrease of $3.18 per barrel from the realized oil price in the fourth quarter and an increase of $0.16 per Mcf in the realized gas price in the fourth quarter.

Product Revenues

Total product revenues were $117.1 million in the fourth quarter of 2013, a four percent decrease compared to $121.6 million in the third quarter of 2013, due primarily to a six percent decrease in average product pricing to $63.58 per BOE from $67.33 per BOE, partially offset by a two percent increase in equivalent production. The realized oil price was 10 percent lower than in the third quarter. Oil and NGL revenues were $105.0 million in the fourth quarter, a three percent decrease compared to $108.8 million in the third quarter, due to a seven percent decrease in oil and NGL prices, partially offset by a four percent increase in oil and NGL production. Oil and NGL revenues were 90 percent of product revenues in the fourth quarter, compared to 89 percent in the third quarter.

Operating Expenses

As discussed below, fourth quarter 2013 total direct operating expenses increased by $0.6 million to $30.4 million, or $16.51 per BOE produced, compared to $29.8 million, or $16.47 per BOE, in the third quarter of 2013.

- Lease operating expenses increased by $2.1 million to $10.6 million, or $5.74 per BOE, from $8.5 million, or $4.68 per BOE, due primarily to downhole repairs and maintenance, both in east Texas and the Eagle Ford Shale.
- Gathering, processing and transportation expenses increased by $0.2 million to $3.2 million, or $1.76 per BOE, compared to $3.0 million, or $1.68 per BOE, related primarily to higher Eagle Ford Shale production.
- Production and ad valorem taxes decreased by $3.7 million to $2.9 million, or 2.5 percent of product revenues, from $6.6 million, or 5.4 percent of product revenues, due primarily to lower than expected ad valorem taxes.
- General and administrative expenses, excluding share-based and liability-based compensation expenses of $3.6 million and acquisition transaction expenses of $0.2 million, increased by $0.3 million to $10.9 million, or $5.94 per BOE, from $10.6 million, or $5.85 per BOE, excluding share-based and liability-based compensation and acquisition transaction expenses of $2.1 million. The increase in share-based and liability-based compensation expenses was due primarily to the increase in our common stock price during the fourth quarter of 2013.

Exploration expense decreased to $2.9 million in the fourth quarter of 2013 from $4.0 million in the third quarter of 2013.

DD&A expense increased by $4.8 million to $67.2 million, or $36.50 per BOE, in the fourth quarter of 2013, from $62.4 million, or $34.56 per BOE, in the third quarter of 2013, due primarily to higher capitalized finding and development costs attributable to our drilling program in the Eagle Ford Shale as well as lower natural gas reserves due to revisions.

Capital Expenditures

During the fourth quarter of 2013, capital expenditures were approximately $150 million, an increase of $30 million, or 25 percent, compared to $120 million in the third quarter of 2013, consisting of:

- $104 million for drilling and completion activities, compared to $112 million in the third quarter;
- $40 million for leasehold acquisitions, compared to $5 million in the third quarter; and.
- $6 million for pipeline, gathering, facilities, seismic and other, compared to $2 million in the third quarter.

Capital Resources and Liquidity, Interest Expense and Impact of Derivatives

As of December 31, 2013, we had total debt of $1,281 million, consisting of $300 million principal amount of 7.25 percent senior unsecured notes due 2019, $775 million of 8.50 percent senior unsecured notes due 2020 and $206 million outstanding under our revolving credit facility (Revolver). Our leverage ratio under the Revolver was 3.7 times trailing twelve months' pro forma Adjusted EBITDAX of approximately $342 million.

In January, we closed on the sale of our Eagle Ford Shale natural gas gathering assets for $100 million, $94 million net to our working interest, which was used to reduce our Revolver balance. As a result, together with cash and cash equivalents of $24 million at December 31, 2013 and given our borrowing base of $425 million, our pro forma liquidity at December 31, 2013 was approximately $340 million. Pro forma for the asset sale, our leverage ratio was 3.5 times trailing twelve months' pro forma Adjusted EBITDAX.

During the fourth quarter, interest expense was $22.3 million, of which $21.3 million was cash interest expense, compared to $20.2 million in the third quarter.

During the fourth quarter, derivatives income was $2.4 million, compared to a derivatives loss of $24.0 million in the third quarter. Fourth quarter 2013 cash settlements of derivatives resulted in net cash outlays of $2.7 million, compared to $4.2 million of net cash outlays in the third 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. Based on hedges currently in place, we have hedged 10,000 barrels of daily crude oil production in 2014, or approximately 62 percent of the midpoint of guidance for 2014 crude oil production, at a weighted average floor/swap price of $93.55 per barrel. For 2015, we have hedged approximately 5,500 barrels of daily crude oil production at a weighted average floor/swap price of $89.10 per barrel.

We have also hedged approximately 12,500 MMBtu of daily natural gas production in 2014, or approximately 31 percent of the midpoint of guidance for 2014 natural gas production, at a weighted average floor/swap price of $4.17 per MMBtu. For the first quarter of 2015, we have hedged 5,000 MMBtu of daily natural gas production at a weighted average floor/swap price of $4.50 per MMBtu.

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

Full-Year 2014 Guidance

Full-year 2014 guidance highlights are as follows:

- Production is expected to be 9.1 to 9.8 MMBOE, or 25,000 to 26,800 BOE per day (BOEPD), an increase of 34 to 43 percent over 2013 production (midpoint increase of 38 percent).
  * 2014 crude oil production guidance is 5,700 to 6,100 thousands of barrels (MBO), or 15,600 to 16,700 barrels of oil per day (BOPD), an increase of 66 to 78 percent over 2013 oil production (midpoint increase of 72 percent).
  * Crude oil and NGL production is expected to be 70 to 80 percent of production (midpoint of 75 percent).
  * Approximately 77 percent of 2014 estimated total production is expected to come from the Eagle Ford Shale.
- Product revenues, excluding the impact of any hedges, are expected to be $587 to $630 million, an increase of 36 to 46 percent over 2013 product revenues (midpoint increase of 21 percent).
  * Our crude oil revenue estimate assumes West Texas Intermediate (WTI) crude oil benchmark pricing of $90 per barrel, with related crude oil pricing for the Eagle Ford Shale oil equal to the WTI price assumption less $2.00 per barrel, which includes the effect of transportation costs. Natural gas pricing is assumed to be $4.00 per Mcf and NGL pricing is assumed to be approximately 32 percent of the WTI price.
  * Crude oil and NGL revenues are expected to be 84 to 97 percent of product revenues (midpoint of 91 percent).
- Adjusted EBITDAX, a non-GAAP measure, is expected to be $440 to $480 million, an increase of 39 to 53 percent over 2013 Adjusted EBITDAX (midpoint increase of 46 percent).
- Capital expenditures are expected to be $575 to $640 million, an increase of 13 to 25 percent over 2013 capital expenditures (midpoint increase of 19 percent).
  * The preliminary 2014 guidance range for capital expenditures was $510 to $540 million. The increase of $65 to $100 million is due to a $40 to $45 million increase in drilling and completion capital expenditures, a $16 to $44 million increase in lease acquisition capital expenditures and a $9 to $11 million increase in pipeline, gathering, facilities, seismic and other capital expenditures. The increase in drilling and completion capital expenditures was driven largely by an approximate $30 million carryover of drilling and completion costs for wells spud in the later portion of 2013 and completed in 2014. The increase in lease acquisition capital expenditures was due to a high activity level of leasing completed thus far in early 2014 and the strategy of achieving our near-term 100,000 acre goal potentially during 2014.
  * Drilling and completion capital expenditures are expected to be $510 to $540 million, an increase of 22 to 29 percent from 2013 drilling and completion capital expenditures (midpoint increase of 26 percent). The increase is explained in the preceding discussion.
  * Pipeline, gathering, facilities, seismic and other capital expenditures are expected to be $25 to $30 million, a decrease of nine to 31 percent from 2013 production facilities and seismic capital expenditures (midpoint decrease of 20 percent).
  * Lease acquisition capital expenditures are expected to be $40 to $70 million, compared to $69 million in 2013 lease acquisition capital expenditures (midpoint decrease of 30 percent).

	2014 Operating Capital Plan				
Project Area	Average Gross Rig Count	Gross/Net Wells Spud in 2014	Gross/Net Wells Completed	Midpoint of Capital Expenditures (millions)	Percent of Capital Expenditures
Drilling and Completions					
Eagle Ford Shale – Shiner	2.6	45/25.1	45/26.3	$280.4	46%
Eagle Ford Shale – Peach Creek	1.8	28/12.7	25/11.3	$102.9	17%
Eagle Ford Shale – Rock Creek	0.9	15/6.0	15/6.0	$48.3	8%
Eagle Ford Shale – SW Gonzales	0.1	2/2.0	2/2.0	$15.9	3%
Eagle Ford Shale – Shallow(1)	0.5	8/6.7	10/7.6	$55.6	9%
Eagle Ford Shale – Contingency(2)	---	---	---	$15.0	2%
Workovers	---	---	---	$6.9	1%
Lease acquisition	---	---	---	$55.0	9%
Pipeline, production facilities, seismic and other	---	---	---	$27.5	5%
Totals	6.0	98/52.5	97/53.2	$607.5	100%

(1) The term "shallow" refers to fields, such as Cannonade Ranch, Kona and the northwest portions of Peach Creek and Cortez for which the top of the Eagle Ford Shale formation is typically shallower than 10,000 feet in vertical depth.

(2) Contingency refers to costs related to unforeseen drilling and/or completion difficulties for the 2014 program.

Please see the Guidance Table included in this release for guidance estimates for full-year 2014. These estimates are meant to provide guidance only and are subject to revision as our operating environment changes.

Explanation of Non-GAAP Operating Margin per BOE

Operating margin is a non-GAAP financial measure which represents total product revenues less total direct operating expenses. Operating margin per BOE is equal to operating margin divided by total equivalent crude oil, NGL and natural gas production. Operating margin is not adjusted for the impact of hedges. We believe that operating margin per BOE is an important measure that can be used by security analysts and investors to evaluate our operating margin per unit of production and to compare it to other oil and gas companies, as well as for comparisons to other time periods.

Fourth Quarter and Full-Year 2013 Conference Call

A conference call and webcast, during which management will discuss fourth quarter 2013 financial and operational results, is scheduled for Thursday, February 20, 2014 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 23232008), or via webcast 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 23232008. 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 Corp. (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 Texas, and other properties in the Mid-Continent, Mississippi and the Marcellus Shale in Appalachia. 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 and natural gas; our ability to develop, explore for, acquire and replace oil and 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, natural gas liquids and natural gas; reductions in the borrowing base under our revolving credit facility; 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 gas reserves; drilling and operating risks; our ability to compete effectively against oil and gas companies; our ability to successfully monetize select assets and repay our debt; leasehold terms expiring before production can be established; environmental 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; 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 their ability to meet their future obligations; changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters; 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. 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.

PENN VIRGINIA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - unaudited

(in thousands, except per share data)

	Three months ended		Twelve months ended	
	December 31,		December 31,	
	2013	2012	2013	2012
Revenues				
Crude oil	$ 96,918	$ 55,472	$ 347,407	$ 229,572
Natural gas liquids (NGLs)	8,096	7,753	30,748	31,051
Natural gas	12,073	12,763	52,538	49,861
Total product revenues	117,087	75,988	430,693	310,484
(Loss) gain on sales of property and equipment, net	213	1,875	(266)	4,282
Other	(298)	331	1,041	2,383
Total revenues	117,002	78,194	431,468	317,149
Operating expenses				
Lease operating	10,570	6,653	35,461	31,266
Gathering, processing and transportation	3,241	2,524	12,839	14,196
Production and ad valorem taxes	2,872	2,719	22,404	10,634
General and administrative (excluding equity-classified share-based compensation) (a)	13,722	8,264	48,217	39,553
Total direct operating expenses	30,405	20,160	118,921	95,649
Share-based compensation - equity classified awards (b)	1,000	2,114	5,781	6,347
Exploration	2,897	7,445	20,994	34,092
Depreciation, depletion and amortization	67,239	54,448	245,594	206,336
Impairments	--	75,168	132,224	104,484
Loss on firm transportation commitment	--	--	--	17,332
Total operating expenses	101,541	159,335	523,514	464,240
Operating income (loss)	15,461	(81,141)	(92,046)	(147,091)
Other income (expense)				
Interest expense	(22,336)	(14,502)	(78,841)	(59,339)
Loss on extinguishment of debt	(17)	(20)	(29,174)	(3,164)
Derivatives	2,356	4,937	(20,852)	36,187
Other	68	27	147	116
Loss before income taxes	(4,468)	(90,699)	(220,766)	(173,291)
Income tax benefit	2,119	36,258	77,696	68,702
Net loss	(2,349)	(54,441)	(143,070)	(104,589)
Preferred stock dividends	(1,725)	(1,687)	(6,900)	(1,687)
Net loss applicable to common shareholders	$ (4,074)	$ (56,128)	$ (149,970)	$ (106,276)
Net loss per share:				
Basic	$ (0.06)	$ (1.05)	$ (2.41)	$ (2.22)
Diluted	$ (0.06)	$ (1.05)	$ (2.41)	$ (2.22)
Weighted average shares outstanding, basic	65,490	53,607	62,335	47,919
Weighted average shares outstanding, diluted	65,490	53,607	62,335	47,919

	Three months ended		Twelve months ended	

	December 31,		December 31,	
	2013	2012	2013	2012
Production				
Crude oil (MBbls)	1,024	559	3,435	2,252
NGLs (MBbls)	234	239	983	884
Natural gas (MMcf)	3,502	3,737	14,435	20,261
Total crude oil, NGL and natural gas production (MBOE)	1,842	1,421	6,824	6,513
Prices				
Crude oil ($ per Bbl)	$ 94.66	$ 99.30	$ 101.13	$ 101.95
NGLs ($ per Bbl)	$ 34.56	$ 32.40	$ 31.30	$ 35.13
Natural gas ($ per Mcf)	$ 3.45	$ 3.41	$ 3.64	$ 2.46
Prices - Adjusted for derivative settlements				
Crude oil ($ per Bbl)	$ 91.48	$ 106.33	$ 100.36	$ 105.69
NGLs ($ per Bbl)	$ 34.56	$ 32.40	$ 31.30	$ 35.13
Natural gas ($ per Mcf)	$ 3.61	$ 3.83	$ 3.75	$ 3.44

(a) Includes liability-classified share-based compensation expense attributable to our performance-based restricted stock units which are payable in cash upon the achievement of certain market-based performance metrics. A total of $2.6 million and $(0.1) million attributable to these awards is included in the three months ended December, 2013 and 2012 and a total of $4.1 million and $0.7 million for the years ended December 31, 2013 and 2012.

(b) 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	
	December 31,	December 31,
	2013	2012
Assets		
Current assets	$ 233,696	$ 96,515
Net property and equipment	2,237,304	1,723,359
Other assets	36,087	23,115
Total assets	$ 2,507,087	$ 1,842,989
Liabilities and shareholders' equity		
Current liabilities	$ 258,145	$ 112,025
Revolving credit facility	206,000	--
Senior notes due 2016	--	294,759
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	--
Other liabilities and deferred income taxes	179,138	241,089
Total shareholders' equity	788,804	895,116
Total liabilities and shareholders' equity	$ 2,507,087	$ 1,842,989

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - unaudited

(in thousands)

	Three months ended		Twelve months ended	
	December 31,		December 31,	
	2013	2012	2013	2012
Cash flows from operating activities				

Net loss	$ (2,349)	$ (54,441)	$ (143,070)	$ (104,589)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Loss on extinguishment of debt	17	--	29,174	3,144
Loss on firm transportation commitment	--	--	--	17,332
Depreciation, depletion and amortization	67,239	54,448	245,594	206,336
Impairments	--	75,168	132,224	104,484
Derivative contracts:				
Net losses (gains)	(2,356)	(4,937)	20,852	(36,187)
Cash settlements	(2,667)	5,534	(1,042)	29,723
Deferred income tax benefit	(2,119)	(36,232)	(77,696)	(68,676)
Loss (gain) on sales of assets, net	(213)	(1,875)	266	(4,282)
Non-cash exploration expense	3,284	7,869	17,451	32,634
Non-cash interest expense	998	955	3,844	4,062
Share-based compensation (equity-classified)	1,000	2,114	5,781	6,347
Other, net	510	701	1,971	1,004
Changes in operating assets and liabilities	(26,666)	1,940	26,163	50,126
Net cash provided by operating activities	36,678	51,244	261,512	241,458
Cash flows from investing activities				
Acquisition, net	20,568	--	(380,694)	--
Capital expenditures - property and equipment	(147,239)	(113,713)	(504,203)	(370,907)
Proceeds from sales of assets, net	(707)	3,443	(54)	96,719
Other, net	--	--	--	180
Net cash used in investing activities	(127,378)	(110,270)	(884,951)	(274,008)
Cash flows from financing activities				
Proceeds from the issuance of preferred stock, net	--	110,337	--	110,337
Proceeds from the issuance of common stock, net	--	43,474	--	43,474
Proceeds from the issuance of senior notes	--	--	775,000	--
Retirement of senior notes	--	(4,915)	(319,090)	(4,915)
Proceeds from revolving credit facility borrowings	83,000	107,000	297,000	211,000
Repayment of revolving credit facility borrowings	(5,000)	(184,000)	(91,000)	(310,000)
Debt issuance costs paid	(435)	(253)	(25,634)	(2,032)
Dividends paid on preferred and common stock	(1,725)	--	(6,862)	(5,176)
Other, net	13	--	(151)	--
Net cash provided by financing activities	75,853	71,643	629,263	42,688
Net increase (decrease) in cash and cash equivalents	(14,847)	12,617	5,824	10,138
Cash and cash equivalents - beginning of period	38,321	5,033	17,650	7,512
Cash and cash equivalents - end of period	$ 23,474	$ 17,650	$ 23,474	$ 17,650
Supplemental disclosures of cash paid for:				
Interest (net of amounts capitalized)	$ 43,303	$ 26,943	$ 64,227	$ 54,808
Income taxes (net of refunds received)	$ --	$ (29)	$ --	$ (32,603)

PENN VIRGINIA CORPORATION

CERTAIN NON-GAAP FINANCIAL MEASURES - unaudited

(in thousands)

	Three months ended December 31,		Twelve months ended December 31,	
	2013	2012	2013	2012
<u>Reconciliation of GAAP "Net loss " to Non-GAAP "Net loss applicable to common shareholders, as adjusted"</u>				
Net loss	$ (2,349)	$ (54,441)	$ (143,070)	$ (104,58

Adjustments for derivatives:				
Net losses (gains)	(2,356)	(4,937)	20,852	(36,187)
Cash settlements	(2,667)	5,534	(1,042)	29,723
Adjustment for acquisition transaction expenses	191	--	2,587	--
Adjustment for impairments	--	75,168	132,224	104,484
Adjustment for restructuring costs	2	9	7	1,293
Adjustment for loss (gain) on sale of assets, net	(213)	(1,875)	266	(4,282)
Adjustment for loss on extinguishment of debt	17	20	29,174	3,164
Adjustment for loss on firm transportation commitment	--	--	--	17,332
Impact of adjustments on income taxes	2,384	(29,550)	(64,781)	(45,801)
Preferred stock dividends	(1,725)	(1,687)	(6,900)	(1,687)
Net loss applicable to common shareholders, as adjusted (a)	$ (6,716)	$ (11,759)	$ (30,683)	$ (36,550)
Net loss applicable to common shareholders, as adjusted, per share, diluted	$ (0.10)	$ (0.22)	$ (0.49)	$ (0.76)

Reconciliation of GAAP "Net loss" to Non-GAAP "Adjusted EBITDAX"

Net loss	$ (2,349)	$ (54,441)	$ (143,070)	$ (104,589
Income tax benefit	(2,119)	(36,258)	(77,696)	(68,702)
Interest expense	22,336	14,502	78,841	59,339
Depreciation, depletion and amortization	67,239	54,448	245,594	206,336
Exploration	2,897	7,445	20,994	34,092
Share-based compensation expense (equity-classified awards)	1,000	2,114	5,781	6,347
EBITDAX	89,004	(12,190)	130,444	132,823
Adjustments for derivatives:				
Net losses (gains)	(2,356)	(4,937)	20,852	(36,187)
Cash settlements	(2,667)	5,534	(1,042)	29,723
Adjustment for loss on firm transportation commitment	--	--	--	17,332
Adjustment for acquisition transaction expenses	191	--	2,587	--
Adjustment for impairments	--	75,168	132,224	104,484
Adjustment for loss (gain) on sale of assets, net	(213)	(1,875)	266	(4,282)
Adjustment for other non-cash items	411	561	1,674	561
Adjustment for loss on extinguishment of debt	17	20	29,174	3,164
Adjusted EBITDAX (b)	84,387	62,281	316,179	247,618
Pro forma EBITDAX from 2013 Eagle Ford Shale Acquisition (1/1/13 through 4/23/2013)	--	--	26,256	--
Pro forma Adjusted EBITDAX	$ 84,387	$ 62,281	$ 342,435	$ 247,618

(a) Net loss applicable to common shareholders, as adjusted, represents the net loss, less preferred stock dividends, adjusted to exclude the effects, net of income taxes, of non-cash changes in the fair value of derivatives, acquisition transaction expenses, impairments, restructuring costs, net gains and losses o the sale of assets, loss on extinguishment of debt and loss on firm transportation commitment. 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 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 loss before income tax benefit, interest expense, depreciation, depletion and amortization expense, exploration expens and share-based compensation expense, further adjusted to exclude the effects of non-cash changes in the fair value of derivatives, acquisition transaction expenses, impairments, net gains and losses on the sale of assets, loss on extinguishment of debt, loss on firm transportation commitment 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 a alternative to net loss. Pro forma Adjusted EBITDAX further adjusts Adjusted EBITDAX to include the pro forma EBITDAX from our Eagle Ford Shale acquisition in April 2013 and represents EBITDAX as defined in our revolving credit facility.

PENN VIRGINIA CORPORATION

GUIDANCE TABLE - unaudited

(dollars in millions except where noted)

We are providing the following guidance regarding financial and operational expectations for full-year 2014. These estimates are meant to provide guidance only and are subject to change as PVA's operating environment changes.

	First Quarter 2013	Second Quarter 2013	Third Quarter 2013	Fourth Quarter 2013	Full-Year 2013	Full-Year 2014 Guidance
Production:						
Crude oil (MBbls)	599	858	954	1,024	3,435	5,700 -- 6,100
NGLs (MBbls)	234	260	254	234	983	1,075 -- 1,175
Natural gas (MMcf)	3,565	3,778	3,591	3,502	14,435	14,000 -- 15,000
Equivalent production (MBOE)	1,427	1,748	1,807	1,842	6,824	9,108 -- 9,775
Equivalent daily production (BOEPD)	15,857	19,209	19,638	20,020	18,695	24,954 -- 26,781
Percent crude oil and NGLs	58.4%	64.0%	66.9%	68.3%	64.7%	69.3% -- 79.9%
Production revenues (a):						
Crude oil	$ 63.1	86.9	100.6	96.9	347.4	500.0 -- 535.0
NGLs	$ 7.1	7.3	8.2	8.1	30.7	32.0 -- 35.0
Natural gas	$ 12.0	15.6	12.9	12.1	52.5	55.0 -- 60.0
Total product revenues	$ 82.2	109.7	121.6	117.1	430.7	587.0 -- 630.0
Total product revenues ($ per BOE)	$ 57.61	62.78	67.33	63.58	63.12	60.05 -- 69.17
Percent crude oil and NGLs	85.4%	85.8%	89.4%	89.7%	87.8%	84.4% -- 97.1%
Operating expenses:						
Lease operating ($ per BOE)	$ 5.47	4.94	4.68	5.74	5.20	5.80 -- 6.40
Gathering, processing and transportation costs ($ per BOE)	$ 2.51	1.70	1.68	1.76	1.88	1.70 -- 1.90
Production and ad valorem taxes (percent of oil and gas revenues)	7.2%	6.4%	5.4%	2.5%	5.2%	6.5% -- 7.5%
General and administrative:						
Recurring general and administrative	$ 9.9	10.2	10.6	10.9	41.5	43.0 -- 46.0
Share-based and liability-based compensation	$ 1.1	3.1	2.1	3.6	9.9	7.0 -- 8.0
Acquisition transaction expenses	---	2.4	---	0.2	2.6	0.0 -- 0.0
Total reported G&A	$ 10.9	15.7	12.7	14.7	54.0	50.0 -- 54.0
Exploration:						
Total reported exploration	$ 6.3	7.8	4.0	2.9	21.0	23.0 -- 25.0
Unproved property amortization	$ 5.3	5.1	3.8	3.4	17.6	12.5 -- 13.0
Depreciation, depletion and amortization ($ per BOE)	$ 36.14	36.80	34.57	36.50	35.99	35.00 -- 36.00
Adjusted EBITDAX (b)	$ 60.3	83.1	88.3	84.4	316.2	440.0 -- 485.0
Capital expenditures:						
Drilling and completion	$ 86.5	116.3	111.9	103.5	418.2	510.0 -- 540.0
Lease acquisitions	$ 5.0	20.0	4.5	39.6	69.2	40.0 -- 70.0
Seismic (c)	$ 1.0	1.8	0.1	0.0	2.9	10.0 -- 12.0
Pipeline, gathering, facilities and other	$ 3.1	8.1	2.4	6.4	20.0	15.0 -- 18.0
Total capital expenditures	$ 95.6	145.4	119.7	149.5	510.2	575.0 -- 640.0
End of period debt outstanding	$ 633.1	1,142.0	1,203.0	1,281.0	1,281.0	1,400.0 -- 1,450.0
Interest expense:						
Total reported interest expense	$ 14.5	21.8	20.2	22.3	78.8	97.0 -- 100.0
Cash interest expense	$ 13.5	20.9	19.3	21.3	74.8	93.0 -- 96.0
Preferred stock dividends paid	$ 1.7	1.7	1.7	1.7	6.9	6.9 -- 6.9
Income tax benefit rate	34.9%	35.0%	34.9%	47.4%	35.2%	35.5% -- 37.5%

(a) Assumes average benchmark prices of $90.42 per barrel for crude oil and $4.16 per MMBtu for natural gas in 2014, prior to any premium or discount for quality, basin differentials, the impact of hedges and other adjustments. NGL realized pricing is assumed to be $29.37 per barrel in 2014.

(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	Ceiling
Natural gas:		(MMBtu)	($ / MMBtu)	
First quarter 2014	Collars	5,000	4.00	4.50
First quarter 2014	Swaps	10,000	4.28	
Second quarter 2014	Swaps	15,000	4.10	
Third quarter 2014	Swaps	15,000	4.10	
Fourth quarter 2014	Swaps	5,000	4.50	
First quarter 2015	Swaps	5,000	4.50	
Crude oil:		(barrels)	($ / barrel)	
First quarter 2014	Collars	1,500	93.33	102.80
Second quarter 2014	Collars	1,500	93.33	102.80
First quarter 2015	Collars (a)	2,000	85.00	95.00
Second quarter 2015	Collars (a)	2,000	85.00	95.00
Third quarter 2015	Collars (a)	2,000	85.00	95.00
Fourth quarter 2015	Collars (a)	2,000	85.00	95.00
First quarter 2014	Swaps	8,500	94.00	94.00
Second quarter 2014	Swaps	8,500	94.00	94.00
Third quarter 2014	Swaps (a)	10,000	93.21	93.21
Fourth quarter 2014	Swaps (a)	10,000	93.21	93.21
First quarter 2015	Swaps (a)	4,000	91.61	91.61
Second quarter 2015	Swaps (a)	4,000	91.61	91.61
Third quarter 2015	Swaps (a)	3,000	91.22	91.22
Fourth quarter 2015	Swaps (a)	3,000	91.22	91.22
First quarter 2015	Swaption (b)	1,000	88.00	
Second quarter 2015	Swaption (b)	1,000	88.00	
Third quarter 2015	Swaption (b)	1,000	88.00	
Fourth quarter 2015	Swaption (b)	1,000	88.00	

(a) All or a portion of these derivatives have include "lower" puts sold at a strike price of $70 per barrel. If the price of WTI oil goes below $70 per barrel, the cash receipts on the derivatives will be limited to the difference between the swap / floor price and $70 per barrel.

(b) This swaption contract gives our counterparties the option to enter into a fixed price swap with us at a future date. If the forward commodity price for calendar year 2015 is higher than or equal to $88.00 per barrel on December 31, 2014, the counterparty will exercise its option to enter into a fixed price swap at $88.00 per barrel for calendar year 2015, at which point the contract functions as a fixed price swap. If the forward commodity price for calendar year 2015 is lower than $88.00 per barrel on December 31, 2014, the option expires and no fixed price swap is in effect.

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 2014 would increase or decrease by approximately $44.0 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 2014 would increase or decrease by approximately $10.2 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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