Penn Virginia Corporation Announces Second Quarter 2014 Results

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RADNOR, Pa., July 30, 2014 (GLOBE NEWSWIRE) -- Penn Virginia Corp. (NYSE:PVA) today reported financial results for the three months ended June 30, 2014 and provided updates of its operations, 2014 guidance and 2015 preliminary guidance.

Key Highlights

- Second quarter production from Eagle Ford Shale operations increased six percent to 15,618 barrels of oil equivalent per day (BOEPD) compared to 14,761 BOEPD in the prior quarter.
    - Since our last quarterly report, our operated Eagle Ford wells had an average initial potential (IP) of 1,514 BOEPD (excluding shallow wells), including one well with an IP of 3,175 BOEPD.
    - Our Upper Eagle Ford well production is exceeding expectations.
- Adjusted second quarter EBITDAX, a non-GAAP (generally accepted accounting principles) measure, grew to $95.0 million from $93.8 million in the first quarter.
- Currently in the Eagle Ford we have 11 (6.3 net) wells completing, 11 (5.0 net) wells waiting on completion and six (4.6 net) wells being drilled.
- Currently in the Eagle Ford we have approximately 143,200 (102,000 net) acres, including the recently announced acquisition of 13,125 (11,660 net) acres for $45 million.
    - Including this pending acquisition, approximately 16,100 net acres, or 19 percent, have been added in the Eagle Ford since our last quarterly report at an average cost of approximately $3,700 per acre.
    - We have increased our undrilled location inventory from approximately 1,510 to approximately 1,635 locations.
- As separately announced, we today closed a $150 million sale of the rights to construct and operate a crude oil gathering and intermediate transportation system in the Eagle Ford.
- We are increasing our rig count in the Eagle Ford to eight in the second half of 2014.
    - Incremental capital expenditures will be funded by our recently completed $325 million convertible preferred equity offering and non-core asset sales.
- We have updated our guidance for full-year 2014 and updated our preliminary guidance for full-year 2015.
    - We decreased our guidance for 2014 production to between 8.8 and 9.2 million BOE (MMBOE), due primarily to less than expected production during the first half of 2014; we reaffirmed our 2014 Adjusted EBITDAX guidance.
    - We increased our preliminary guidance for 2015 production growth over 2014 to approximately 45 percent for oil and approximately 35 percent overall; we increased guidance for our 2015 Adjusted EBITDAX growth over 2014 to between 35 and 40 percent.

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 second quarter of 2014, our cash flows and margins remained strong and were in line with our expectations, despite our production being challenged by the timing and operational complexities associated with pad drilling and completions. We have expanded our ongoing pad drilling program in the Eagle Ford and are encouraged by our recent results in the play, especially our results in the Upper Eagle Ford. We are modestly reducing our full year production guidance, but we remain confident that we can deliver significantly higher production levels in the second half of 2014 as we realize the ongoing benefit of our pad completions and rig expansions along with an increased focus on the Upper Eagle Ford."

Whitehead continued, "We are very pleased with the results of the oil gathering and transportation rights sale, which is another step forward in our efforts to improve our liquidity and fund additional investment and further growth in the Eagle Ford. This transaction, along with the pending sale of our Mississippi assets, brings the total proceeds from 2014 asset sales to $319 million, exceeding our original goal of up to $300 million."

Whitehead concluded, "These asset sales and the convertible preferred offering provide us with the financial flexibility to fund operations through 2015, while also allowing us to significantly reduce our leverage ratio. We are increasing our capital expenditures in the second half to support the addition of two new rigs, which will position us to realize improved production in the second half and approximately 45 percent growth in oil production for 2015. We are excited about our future prospects and are committed to executing our strategic plan to deliver significant long-term shareholder value."

Second Quarter 2014 Results

Overview of Results

Operating income of $26.3 million in the second quarter of 2014, excluding $117.9 million of impairments, was $11.4 million higher than $14.9 million in the first quarter of 2014, excluding $56.8 million of gain on the sale of assets. This 77 percent increase was due primarily to a $6.4 million increase in product and other revenues, a $5.2 million decrease in exploration expense, a $4.9 million decrease in share-based compensation expenses and a $0.8 million decrease in depletion, depreciation and amortization (DD&A) expense. The effect of these favorable increases was partially offset by a $3.1 million increase in general and administrative (G&A) expense, excluding share-based compensation expenses, and a $2.8 million increase in lease operating, gathering, processing and transportation expenses and production and ad valorem taxes.

Net loss attributable to common shareholders for the second quarter was $105.9 million, or $1.59 per diluted share, compared to net income of $17.5 million, or $0.22 per diluted share, in the prior quarter. Adjusted net loss attributable to common shareholders for the second quarter, a non-GAAP measure which includes our preferred stock dividend but excludes the effects of other items that affect comparability to other periods, was $4.3 million, or $0.07 per diluted share, compared to a loss of $7.9 million, or $0.12 per diluted share in the prior quarter.

Product Revenues

Total product revenues were $136.4 million, or $68.81 per barrel of oil equivalent (BOE), in the second quarter of 2014, a two percent increase compared to $133.2 million, or $70.01 per BOE, in the first quarter due primarily to a four percent increase in equivalent production and a two percent increase in the realized oil price, partially offset by a 25 percent decrease in the realized natural gas liquid (NGL) price and an 11 percent decrease in the realized natural gas price. Oil and NGL revenues were $120.1 million in the second quarter, a five percent increase compared to $114.9 million in the first quarter due to a six percent increase in combined oil and NGL production, partially offset by a one percent decrease in combined oil and NGL prices. Oil and NGL revenues were 88 percent of product revenues in the second quarter, compared to 86 percent in the first quarter. Natural gas revenues were $16.3 million in the second quarter, a 10 percent decrease compared to $18.2 million in the first quarter due to an 11 percent decrease in natural gas prices, partially offset by a one percent increase in natural gas production.

Production

As shown in the table below, production in the second quarter of 2014 was 21,786 BOEPD, compared to 21,133 BOEPD in the first quarter of 2014. As a percentage of total equivalent production, oil and NGL volumes were 70 percent in the second quarter of 2014, compared to 69 percent in the first quarter of 2014.

	Total and Daily Equivalent Production for the Three Months Ended					
	June 30,	Mar. 31,	Dec. 31,	June 30,	Mar. 31,	Dec. 31,
Region / Play Type	2014	2014	2013	2014	2014	2013
	(in MBOE)			(in BOEPD)		

Eagle Ford Shale	1,421	1,329	1,209	15,618	14,761	13,145
East Texas	220	215	241	2,417	2,394	2,624
Mid-Continent	161	174	204	1,770	1,931	2,213
Mississippi / Other	180	184	187	1,981	2,047	2,037
Totals	1,983	1,902	1,842	21,786	21,133	20,020

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

Operating Expenses

As discussed below, second quarter 2014 total direct operating expenses, excluding share-based compensation expenses, increased by $5.8 million to $36.4 million, or $18.36 per BOE produced, compared to $30.6 million, or $16.08 per BOE, in the first quarter of 2014.

- Lease operating expenses increased by $2.0 million to $12.4 million, or $6.25 per BOE, from $10.4 million, or $5.47 per BOE, due to higher water disposal, chemical, fuel and lubricant costs, as well as higher compression costs related to a new gathering and compression agreement following the first quarter 2014 sale of our natural gas midstream assets in the Eagle Ford.
- Gathering, processing and transportation expenses increased by $0.6 million to $3.5 million, or $1.78 per BOE, compared to $2.9 million, or $1.56 per BOE, related to higher gas production volumes and increased transportation expense as a result of the new gathering and compression agreement.
- Production and ad valorem taxes increased by $0.2 million to $7.5 million, or 5.5 percent of product revenues, from $7.3 million, or 5.5 percent of product revenues, due to higher product revenues.
- G&A expense, excluding share-based compensation expenses of $1.9 million, increased by $3.1 million to $13.0 million, or $6.54 per BOE, from $9.9 million, or $5.21 per BOE, excluding share-based compensation expenses of $6.8 million. Approximately $1.1 million of the increase in G&A expense was due to non-recurring costs related to the replacement of our enterprise resource planning software, 2013-related arbitration costs and asset sale transactions. The decrease in share-based compensation expenses was due to a lower common stock price in the second quarter of 2014.

Exploration expense decreased to $3.4 million in the second quarter from $8.6 million in the first quarter, due primarily to decreased expenditures for seismic data.

DD&A expense decreased by $0.8 million to $71.4 million, or $36.03 per BOE, in the second quarter, from $72.2 million, or $37.95 per BOE, in the first quarter, due to lower depletion rates.

In the second quarter, we incurred a $117.9 million impairment charge as a result of writing down our Mississippi properties to fair value.

Capital Expenditures

During the second quarter of 2014, capital expenditures were $170 million, a decrease of $12 million, or seven percent, compared to $182 million in the first quarter of 2014, consisting of:

- $154 million for drilling and completion activities, compared to $135 million in the first quarter;
- $13 million for leasehold acquisitions, compared to $37 million in the first quarter; and
- $3 million for pipeline, gathering, facilities, seismic and other, compared to $10 million in the first quarter.

Capital Resources and Liquidity, Interest Expense and Impact of Derivatives

As of June 30, 2014, we had total debt of $1,130 million, consisting of $300 million principal amount of 7.25 percent senior unsecured notes due 2019, $775 million principal amount of 8.50 percent senior unsecured notes due 2020 and $55 million outstanding under our revolving credit facility (Revolver). In June 2014, we completed the offering of $325 million of Series B convertible perpetual preferred stock depositary shares. Moreover, year-to-date through June 30, 2014, approximately $26 million of our Series A convertible perpetual preferred stock depositary shares have converted into common shares. As a result, at June 30, 2014, we had outstanding convertible perpetual preferred stock depositary shares with a face value of approximately $414 million. Our leverage ratio under the Revolver at June 30, 2014 was 3.1 times trailing twelve months' pro forma Adjusted EBITDAX of approximately $362 million, compared to 3.6 times at March 31, 2014.

As separately announced, we today closed a sale of our rights to construct and operate a crude oil gathering and intermediate transportation system covering a portion of our Eagle Ford acreage for $150 million, and we expect to close the sale of our Mississippi Selma Chalk producing properties on July 31, 2014 for a price of approximately $73 million, bringing year-to-date asset sale proceeds to approximately $319 million. Earlier this month, we also announced an approximate $45 million acquisition in the Eagle Ford, of which approximately $34 million will be paid up front and the $11 million balance will be a drilling carry. Pro forma for these transactions, our leverage ratio under the Revolver at June 30, 2014 was approximately 2.6 times. In July 2014, there was a favorable final settlement of arbitration of approximately $34 million related to our significant 2013 Eagle Ford acquisition.

During the second quarter, interest expense was $23.2 million, of which $22.2 million was cash interest expense, compared to $22.5 million in the first quarter.

During the second quarter, derivatives loss was $42.7 million, compared to derivatives loss of $15.7 million in the first quarter. Second quarter 2014 cash settlements of derivatives resulted in net cash outlays of $7.2 million, compared to $3.1 million of net cash outlays in the first quarter.

Pricing

Our second quarter 2014 realized oil price was $100.16 per barrel, compared to $98.12 per barrel in the first quarter of 2014. Our second quarter 2014 realized NGL price was $30.85 per barrel, compared to $41.27 per barrel in the first quarter. Our second quarter 2014 realized natural gas price was $4.51 per thousand cubic feet (Mcf), compared to $5.07 per Mcf in the first quarter. Adjusting for oil and gas hedges, our second quarter 2014 effective oil price was $94.72 per barrel and our second quarter 2014 effective natural gas price was $4.20 per Mcf, or a decrease of $5.44 per barrel from the realized oil price and a decrease of $0.31 per Mcf in the realized gas price.

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 12,500 barrels of daily crude oil production, or approximately 70 percent of the midpoint of guidance for the second half of 2014, at a weighted average floor/swap price of $92.80 per barrel. For 2015, we have hedged approximately 11,500 barrels of daily crude oil production at a weighted average floor/swap price of $90.17 per barrel. For 2016, we have hedged 3,000 barrels of daily crude oil production at a weighted average floor/swap price of $90.84 per barrel.

We have also hedged 10,000 MMBtu (million British Thermal Units) of daily natural gas production, or approximately 25 percent of the midpoint of guidance for the second half of 2014, at a weighted average floor/swap price of $4.20 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 and Preliminary Full-Year 2015 Guidance

2014 capital expenditures are expected to range between $762 and $808 million ($410 to $456 million for the second half of 2014), which is an increase of $155 to $167 million from previous guidance. This reflects increases in drilling and completion capital expenditures of between $125 and $130 million and in lease acquisition capital expenditures of between $32 and $37 million. The increase in drilling and completion expenditures is attributable to the addition of a seventh drilling rig in August 2014 and an eighth drilling rig estimated to commence drilling in September 2014. As a result of the additional rigs, we expect to turn in line

68 (39.0 net) wells during the remainder of 2014, for a total of 111 (67.0 net) operated wells (excludes shallow wells) to be turned in line during 2014, along with a production contribution associated with the seventh and eighth rigs of 700 to 800 MBOE in the fourth quarter of 2014.

2014 production is expected to range between approximately 8.8 and 9.2 MMBOE (5.0 to 5.3 MMBOE in the second half of 2014). This represents a decrease of between 7 and 290 MBOE from previous guidance, excluding approximately 260 MBOE of production from our Mississippi assets, the sale of which we expect to close on July 31, 2014. 2014 oil production is expected to range between approximately 5.3 and 5.6 million barrels of oil (3.1 to 3.4 MMBO in the second half of 2014). This represents a decrease of between 400 and 550 MBOE barrels from previous guidance and is due primarily to delays in the timing of completions during the first half of 2014 resulting from operational complexities associated with pad drilling and completions.

The company average production in July 2014, through July 25th, is estimated at 23,800 BOEPD, compared to 21,786 BOEPD for the second quarter. As the seventh and eighth drilling rigs are expected to be active by the end of the third quarter, a significant jump in production is expected to take place during the fourth quarter, while the third quarter is expected to show a modest increase over the second quarter.

2014 Adjusted EBITDAX, which includes the cash impact of derivatives, is expected to range between $425 and $500 million ($251 to $296 million during the second half of 2014), unchanged from previous guidance. We assume the benchmark (WTI) oil price will average $90 per barrel and the benchmark (Henry Hub) natural gas price will average $4.50 per MMBTU in the second half of 2014.

With the two additional drilling rigs, we now estimate total production growth of approximately 35 percent in 2015 and oil production growth of approximately 45 percent in 2015, as compared to previous guidance for total production growth in excess of 30 percent and oil production growth in excess of 40 percent, which assumed a seven drilling rig program.

We estimate that 2015 capital expenditures will range between $750 and $800 million and include approximately $710 to $750 million for drilling and completion expenditures. 2015 Adjusted EBITDAX is expected to be between 35 and 40 percent higher than 2014. We assume the WTI oil price will average $90 per barrel and the Henry Hub natural gas price will average $4.25 per MMBTU in 2015.

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.

Eagle Ford Shale Operational Update

Second Quarter 2014 Update

Second quarter production from our Eagle Ford operations was 15,618 BOEPD, up six percent compared to 14,761 BOEPD in the first quarter, 75 percent of which was crude oil. In June 2014, our average production was 16,861 BOEPD, 74 percent of which was from crude oil. Through July 25, 2014, our average Eagle Ford production in July 2014 is estimated at 18,100 BOEPD. Year-to-date, we have turned in line 43 (28.0 net) operated wells (excludes shallow wells).

Below are the results and statistics for Eagle Ford wells over the past five quarters: [1]

		Averages								
					Peak Gross Daily Production Rates[2]			30-Day Average Gross Daily Production Rates[2]		
	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										

2013 - 2nd quarter	14 / 8.6	5,588	23.0	5,184,664	1,181	1,397	85%	691	845	82%
2013 - 3rd quarter	10 / 5.6	5,901	23.8	6,526,680	1,375	1,596	86%	879	1,036	85%
2013 - 4th quarter	15 / 7.3	5,730	24.1	7,789,759	1,418	1,624	87%	960	1,119	86%
2014 - 1st quarter	14 / 10.2	5,836	25.2	7,791,564	1,159	1,457	80%	695	844	82%
2014 - 2nd quarter(3)	25 / 15.2	5,527	25.4	9,327,075	1,220	1,514	81%	727	948	77%
Totals and averages	78 / 47.0	5,680	24.5	7,653,298	1,260	1,515	83%	789	956	82%
Operating Area										
Shiner -- "Beer Quad"	17 / 8.0	5,970	26.4	9,350,587	1,581	1,899	83%	1,097	1,340	82%
Upper Eagle Ford(4)	2 / 1.9	5,917	26.5	9,970,830	917	1,763	52%	830	1,502	55%
Shiner - Mod. GOR	12 / 9.2	5,124	21.7	6,579,536	1,118	1,346	83%	628	763	82%
Peach Creek	25 / 11.7	6,002	25.2	7,229,596	1,352	1,493	91%	907	1,002	91%
Rock Creek / Bozka(3)	8 / 3.7	6,152	26.8	9,041,509	1,339	1,527	88%	848	955	89%
Shiner - High GOR	14 / 12.5	4,928	21.6	6,144,944	833	1,189	70%	500	706	70%
Totals and averages	78 / 47.0	5,680	24.5	7,653,298	1,260	1,515	83%	789	956	82%

(1) Excludes non-operated wells and "shallow" wells, defined as wells whose vertical depth, including the "curve," is 10,500 feet or less.

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

(3) 30-day information for the Wombat #1H -- #4H wells or the Bock #1H -- #7H wells (11 wells in total) is not yet available. Includes information for the Cinco Ranch LTD Unit #1H well, which was brought on line in July 2014.

(4) Does not include the Fojtik #1H (Upper Eagle Ford well brought on line in March 2013).

Since our last quarterly report, we have turned in line 25 (15.2 net) operated wells (excludes shallow wells). As a group, these 25 wells had an average IP rate of 1,514 BOEPD over an average of 25.4 frac stages, with 81 percent of production from crude oil. Of these 25 wells, 15 wells with sufficient production history had a 30-day average rate of 948 BOEPD, with 77 percent of production from crude oil. In the first quarter, the average IP rate was 1,457 BOEPD over an average of 25.2 frac stages, with 80 percent of production from crude oil. Among the recent wells, the wells with the highest IP rates included the Bock #7H (3,175 BOEPD, a company record, over 26 frac stages), the Cinco Ranch LTD Unit #1H (2,611 BOEPD over 32 frac stages), the Bock #6H (2,272 BOEPD over 26 frac stages), the Amber #1H (2,217 BOEPD over 23 frac stages), the Amber #2H (1,919 BOEPD over 22 frac stages) and the Wombat #1H (1,670 BOEPD over 20 frac stages).

The strong performances of these recent wells was attributable primarily to contributions from wells located in the "beer quad" area near Shiner, the Peach Creek area and the Rock Creek Ranch / Bozka areas. In addition, the amount of proppant per stage increased from an average of 311,000 pounds in the first quarter of 2014 to an average of 370,000 pounds in the second quarter. Costs per stage, on the other hand, decreased from $411,000 in the first quarter of 2014 to $373,000 in the second quarter.

Upper Eagle Ford (Marl) Shale Update

To date, we have tested three Upper Eagle Ford (Marl) Shale wells (Fojtik #1H, Welhausen #A2H and Martinsen #2H) and for the remainder of 2014 we have 19 additional Upper Eagle Ford wells planned to spud, with eight of those scheduled as development wells in the Welhausen area.

The Welhausen #A2H was turned in line in March 2014 and has averaged 1,070 BOEPD over 95 days, 1,519 BOEPD over its first 60 days, 1,767 BOEPD over its first 30 days and had an IP rate of 2,165 BOEPD, with an oil and NGL percentage of approximately 70 percent. The Martinsen #2H was turned in line in May 2014 and has averaged 1,149 BOEPD over its first 60 days, 1,238 BOEPD over its first 30 days and had an IP rate of 1,360 BOEPD, with an oil and NGL percentage of approximately 74 percent.

After observing the performance of these wells relative to adjacent wells in the Lower Eagle Ford, we have increasing confidence that, at least in these areas, the Upper Eagle Ford and Lower Eagle Ford are separate reservoirs. During the second half of 2014, we will continue to test the Upper Eagle Ford across other portions of our Lavaca County acreage, with 11 additional wells planned to be spud in these other areas and all of those associated with pad drilling.

Explanation of Non-GAAP Cash Margin per BOE

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

Second Quarter 2014 Conference Call

A conference call and webcast, during which management will discuss second quarter 2014 financial and operational results, is scheduled for Thursday, July 31, 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 3711735), 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 3711735. 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 south and east 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; 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; 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 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; 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; compliance with and 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		Three months ended	Six months ended	
	June 30,		March 31,	June 30,	
	2014	2013	2014	2014	2013
Revenues					
Crude oil	$ 112,090	$ 86,867	$ 105,576	$ 217,666	$ 149,9
Natural gas liquids (NGLs)	8,037	7,313	9,373	17,410	14,440
Natural gas	16,302	15,554	18,203	34,505	27,593
Total product revenues	136,429	109,734	133,152	269,581	191,958
(Loss) gain on sales of property and equipment, net	(51)	256	56,826	56,775	(293)
Other	2,983	(335)	(113)	2,870	1,188
Total revenues	139,361	109,655	189,865	329,226	192,853
Operating expenses					
Lease operating	12,403	8,629	10,404	22,807	16,434
Gathering, processing and transportation	3,526	2,980	2,961	6,487	6,559
Production and ad valorem taxes	7,510	6,976	7,305	14,815	12,935
General and administrative (excluding equity-classified share-based compensation) (a)	14,014	12,970	15,863	29,877	22,828
Total direct operating expenses	37,453	31,555	36,533	73,986	58,756
Share-based compensation - equity classified awards (b)	826	2,686	825	1,651	3,771
Exploration	3,373	7,845	8,636	12,009	14,140
Depreciation, depletion and amortization	71,437	64,329	72,187	143,624	115,905
Impairment	117,908	--	--	117,908	--
Total operating expenses	230,997	106,415	118,181	349,178	192,572
Operating income (loss)	(91,636)	3,240	71,684	(19,952)	281
Other income (expense)					
Interest expense	(23,229)	(21,808)	(22,534)	(45,763)	(36,287
Loss on extinguishment of debt	--	(29,157)	--	--	(29,157
Derivatives	(42,665)	8,588	(15,662)	(58,327)	827
Other	30	17	1	31	44
Income (loss) before income taxes	(157,500)	(39,120)	33,489	(124,011)	(64,292
Income tax (expense) benefit	56,716	13,682	(14,264)	42,452	22,471
Net income (loss)	(100,784)	(25,438)	19,225	(81,559)	(41,821
Preferred stock dividends	(1,718)	(1,725)	(1,722)	(3,440)	(3,450)
Induced conversion of preferred stock	(3,368)	--	--	(3,368)	--
Net income (loss) attributable to common shareholders	$ (105,870)	$ (27,163)	$ 17,503	$ (88,367)	$ (45,27
Net income (loss) per share:					
Basic	$ (1.59)	$ (0.43)	$ 0.27	$ (1.34)	$ (0.77)
Diluted	$ (1.59)	$ (0.43)	$ 0.22	$ (1.34)	$ (0.77)
Weighted average shares outstanding, basic	66,514	62,899	65,611	66,065	59,141
Weighted average shares outstanding, diluted	66,514	62,899	85,744	66,065	59,141

	Three months ended		Three months ended	Six months ended	
	June 30,		March 31,	June 30,	
	2014	2013	2014	2014	2013
Production					

Crude oil (MBbls)	1,119	858	1,076	2,195	1,457
NGLs (MBbls)	261	260	227	488	494
Natural gas (MMcf)	3,618	3,778	3,593	7,211	7,342
Total crude oil, NGL and natural gas production (MBOE)	1,983	1,748	1,902	3,885	3,175
Prices					
Crude oil ($ per Bbl)	$ 100.16	$ 101.23	$ 98.12	$ 99.16	$ 102.8
NGLs ($ per Bbl)	$ 30.85	$ 28.10	$ 41.27	$ 35.71	$ 29.21
Natural gas ($ per Mcf)	$ 4.51	$ 4.12	$ 5.07	$ 4.78	$ 3.76
Prices - Adjusted for derivative settlements					
Crude oil ($ per Bbl)	$ 94.72	$ 104.10	$ 96.00	$ 95.35	$ 106.5
NGLs ($ per Bbl)	$ 30.85	$ 28.10	$ 41.27	$ 35.71	$ 29.21
Natural gas ($ per Mcf)	$ 4.20	$ 4.06	$ 4.85	$ 4.51	$ 3.83

(a) Includes liability-classified share-based compensation expense attributable to our performance-based restricted stock units, which is payable in cash upon the achievement of certain market-based performance metrics. A total of $1.0 million and $0.4 million and $7.0 million and $0.5 million attributable to these awards is included in the three and six months ended June 30, 2014 and 2013, respectively.

(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	
	June 30,	December 31,
	2014	2013
Assets		
Current assets	$336,873	$233,696
Net property and equipment	2,217,954	2,237,304
Other assets	32,853	36,087
Total assets	$2,587,680	$2,507,087
Liabilities and shareholders' equity		
Current liabilities	$284,552	$258,145
Revolving credit facility	55,000	206,000
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	775,000
Other liabilities and deferred income taxes	156,736	179,138
Total shareholders' equity	1,016,392	788,804
Total liabilities and shareholders' equity	$2,587,680	$2,507,087

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - unaudited

(in thousands)

	Three months ended		Three months ended	Six months ended	
	June 30,		March 31,	June 30,	
	2014	2013	2014	2014	2013
Cash flows from operating activities					
Net income (loss)	$(100,784)	$(25,438)	$19,225	$(81,559)	$(41,821)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Loss on extinguishment of debt	--	29,157	--	--	29,157
Depreciation, depletion and amortization	71,437	64,329	72,187	143,624	115,905
Accretion of firm transportation obligation	230	649	354	584	856

Impairment	117,908	--	--	117,908	--
Derivative contracts:					
Net losses (gains)	42,665	(8,588)	15,662	58,327	(827)
Cash settlements, net	(7,222)	2,233	(3,057)	(10,279)	5,790
Deferred income tax expense (benefit)	(56,516)	(13,682)	14,064	(42,452)	(22,471)
(Gain) loss on sales of assets, net	51	(256)	(56,826)	(56,775)	293
Non-cash exploration expense	3,285	5,146	3,294	6,579	10,408
Non-cash interest expense	1,039	939	1,012	2,051	1,885
Share-based compensation (equity-classified)	826	2,686	825	1,651	3,771
Other, net	75	1	206	281	82
Changes in operating assets and liabilities	(40,361)	26,960	(386)	(40,747)	26,723
Net cash provided by operating activities	32,633	84,136	66,560	99,193	129,751
Cash flows from investing activities					
Acquisition, net	--	(358,239)	--	--	(358,239)
Payments to settle obligations assumed in acquisition, net	--	(36,310)	--	--	(36,310)
Capital expenditures - property and equipment	(190,776)	(143,346)	(159,804)	(350,580)	(229,319)
Proceeds from sales of assets, net	668	(11)	95,964	96,632	867
Net cash used in investing activities	(190,108)	(537,906)	(63,840)	(253,948)	(623,001)
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 the issuance of senior notes	--	775,000	--	--	775,000
Retirement of senior notes	--	(319,090)	--	--	(319,090)
Proceeds from revolving credit facility borrowings	217,000	115,000	85,000	302,000	153,000
Repayment of revolving credit facility borrowings	(352,000)	(86,000)	(101,000)	(453,000)	(86,000)
Debt issuance costs paid	(151)	(24,698)	--	(151)	(24,698)
Dividends paid on preferred and common stock	(2,111)	(1,725)	(1,725)	(3,836)	(3,412)
Other, net	--	(49)	1,085	1,085	(110)
Net cash provided by (used in) financing activities	173,016	458,438	(16,640)	156,376	494,690
Net increase (decrease) in cash and cash equivalents	15,541	4,668	(13,920)	1,621	1,440
Cash and cash equivalents - beginning of period	9,554	14,422	23,474	23,474	17,650
Cash and cash equivalents - end of period	$25,095	$19,090	$9,554	$25,095	$19,090
Supplemental disclosures of cash paid for:					
Interest	$46,009	$22,876	$1,025	$47,034	$23,215
Income taxes (net of refunds received)	$100	$ --	$ --	$100	$ --

PENN VIRGINIA CORPORATION

CERTAIN NON-GAAP FINANCIAL MEASURES - unaudited

(in thousands)

	Three months ended June 30,		Th M
	2014	2013	20
Reconciliation of GAAP "Net income (loss) " to Non-GAAP "Net income (loss) applicable to common shareholders, as adjusted"			
Net income (loss)	$ (100,784)	$ (25,438)	$
Adjustments for derivatives:			
Net losses (gains)	42,665	(8,588)	15
Cash settlements, net	(7,222)	2,233	(3
Adjustment for acquisition transaction expenses	--	2,396	--
Adjustment for impairments	117,908	--	--

Adjustment for restructuring costs	(3)	--	12
Adjustment for (gain) loss on sale of assets, net	51	(256)	(5
Adjustment for loss on extinguishment of debt	--	29,157	--
Impact of adjustments on income taxes	(55,239)	(8,723)	18
Preferred stock dividends	(1,718)	(1,725)	(1
Net loss applicable to common shareholders, as adjusted (a)	$ (4,342)	$ (10,944)	$
<u>Net loss applicable to common shareholders, as adjusted, per share, diluted</u>	$ (0.07)	$ (0.17)	$
<u>Reconciliation of GAAP "Net income (loss)" to Non-GAAP "Adjusted EBITDAX"</u>			
Net income (loss)	$ (100,784)	$ (25,438)	$
Income tax benefit	(56,716)	(13,682)	14
Interest expense	23,229	21,808	22
Depreciation, depletion and amortization	71,437	64,329	72
Exploration	3,373	7,845	8,
Share-based compensation expense (equity-classified awards)	826	2,686	82
EBITDAX	(58,635)	57,548	13
Adjustments for derivatives:			
Net losses (gains)	42,665	(8,588)	15
Cash settlements, net	(7,222)	2,233	(3
Adjustment for acquisition transaction expenses	--	2,396	--
Adjustment for impairments	117,908	--	--
Adjustment for (gain) loss on sale of assets, net	51	(256)	(5
Adjustment for other non-cash items	230	647	35
Adjustment for loss on extinguishment of debt	--	29,157	--
Adjusted EBITDAX (b)	94,997	83,137	93
Pro forma EBITDAX from our 2013 Eagle Ford Shale acquisition	--	3,607	--
Pro forma Adjusted EBITDAX	$ 94,997	$ 86,744	$

(a) Net loss applicable to common shareholders, as adjusted, represents net loss, less preferred stock dividends, adjusted to exclude the effects, net of incor value of derivatives, acquisition transaction expenses, impairments, restructuring costs, net gains and losses on the sale of assets and loss on extinguishmer commonly used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of companies within tl industry. We use this information for comparative purposes within our industry. Net loss applicable to common shareholders, as adjusted, is not a measure o 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 expense, further adjusted to exclude the effects of non-cash changes in the fair value of derivatives, acquisition transaction expenses, impairments, net gains extinguishment of debt and other non-cash items. We believe this presentation is commonly used by investors and professional research analysts in the valu recommendations of companies within the oil and gas exploration and production industry. We use this information for comparative purposes within our indus of financial performance under GAAP and should not be considered as a measure of liquidity or as an alternative to net loss. Pro forma Adjusted EBITDAX fu 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 2014	Second Quarter 2014	First Half 2014	Full-Year 2014 Guidance		
Production:						
Crude oil (MBbls)	1,076	1,119	2,195	5,300	--	5,550
NGLs (MBbls)	227	261	488	1,175	--	1,225

Natural gas (MMcf)	3,593	3,618	7,211	14,200	--	14,700
Equivalent production (MBOE)	1,902	1,983	3,885	8,842	--	9,225
Equivalent daily production (BOEPD)	21,133	21,786	21,461	24,224	--	25,274
Percent crude oil and NGLs	68.5%	69.6%	69.1%	72.5%	--	74.1%
Production revenues (a):						
Crude oil	$105.6	112.1	217.7	485.0	--	520.0
NGLs	$9.4	8.0	17.4	40.0	--	45.0
Natural gas	$18.2	16.3	34.5	65.0	--	72.0
Total product revenues	$133.2	136.4	269.6	590.0	--	637.0
Total product revenues ($ per BOE)	$70.01	68.81	69.40	66.73	--	69.05
Percent crude oil and NGLs	86.3%	88.1%	87.2%	87.9%	--	89.7%
Operating expenses:						
Lease operating ($ per BOE)	$5.47	6.25	5.87	5.30	--	5.90
Gathering, processing and transportation costs ($ per BOE)	$1.56	1.78	1.67	1.80	--	2.05
Production and ad valorem taxes (percent of oil and gas revenues)	5.5%	5.5%	5.5%	6.0%	--	7.0%
General and administrative:						
Recurring general and administrative	$9.7	11.8	21.5	42.5	--	44.0
Non-recurring general and administrative	$0.2	1.1	1.3	1.3	--	1.3
Share-based compensation	$6.8	1.9	8.6	12.0	--	15.0
Total reported G&A	$16.7	14.8	31.5	55.8	--	60.3
Exploration:						
Total reported exploration	$8.6	3.4	12.0	22.0	--	24.0
Unproved property amortization	$3.3	3.4	6.7	13.0	--	13.5
Depreciation, depletion and amortization ($ per BOE)	$37.95	36.03	36.97	36.00	--	37.00
Adjusted EBITDAX (b)	$93.8	95.0	188.8	440.0	--	485.0
Capital expenditures:						
Drilling and completion	$135.5	154.0	289.5	640.0	--	665.0
Lease acquisitions	$36.9	12.8	49.7	97.0	--	115.0
Seismic (c)	$4.5	0.1	4.6	8.0	--	9.0
Pipeline, gathering, facilities and other	$5.6	2.6	8.2	17.0	--	19.0
Total capital expenditures	$182.4	169.5	351.9	762.0	--	808.0
End of period debt outstanding	$1,265.0	1,130.0	1,130.0	1,075.0	--	1,140.0
Interest expense:						
Total reported interest expense	$22.5	23.2	45.8	91.0	--	94.0
Cash interest expense	$21.5	22.2	43.7	86.0	--	91.0
Preferred stock dividends paid	$1.7	2.1	3.8	16.3	--	16.3
Income tax benefit rate	42.6%	36.0%	34.2%	36.5%	--	38.5%

(a) Assumes average benchmark prices of $90.00 per barrel for crude oil and $4.50 per MMBtu for natural gas in the second half of 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 $29.06 per barrel in the second half of 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.

	Instrument Type	Average Volume Per Day	Weighted Average Price Floor/ Swap	Ceiling
Natural gas:		(MMBtu)	($ / MMBtu)	
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)	
Third quarter 2014	Collars	2,000	90.00	94.33
Fourth quarter 2014	Collars	2,000	90.00	94.33
First quarter 2015	Collars (a)	4,000	87.50	94.66
Second quarter 2015	Collars (a)	4,000	87.50	94.66
Third quarter 2015	Collars (a)	3,000	86.67	94.73
Fourth quarter 2015	Collars (a)	3,000	86.67	94.73
Third quarter 2014	Swaps (a)	10,000	93.21	
Fourth quarter 2014	Swaps (a)	11,000	93.45	
First quarter 2015	Swaps (a)	9,000	91.81	
Second quarter 2015	Swaps (a)	9,000	91.81	
Third quarter 2015	Swaps (a)	7,000	91.09	
Fourth quarter 2015	Swaps (a)	7,000	91.09	
First quarter 2016	Swaps	3,000	90.84	
Second quarter 2016	Swaps	3,000	90.84	
Third quarter 2016	Swaps	3,000	90.84	
Fourth quarter 2016	Swaps	3,000	90.84	
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 the second half of 2014 would increase or decrease by approximately $39.1 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 second half of 2014 would increase or decrease by approximately $7.9 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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