PENN VIRGINIA CORPORATION

4th Quarter & Full-Year 2017 Earnings and 2018 Outlook Presentation

– March 2, 2018 –

Nasdaq Ticker: PVAC

Forward Looking and Cautionary Statements

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. We use words such as "guidance," "projects," "estimates," “expects," "continues," "intends," “plans,” "believes," forecasts," "future," and variations of such words or similar expressions in this press release to identify forward-looking statements. Because such statements include assumptions, 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: risks related to the recently completed acquisitions, including the Company's ability to realize their expected benefits; our ability to satisfy our short-term and long-term liquidity needs, including our ability to generate sufficient cash flows from operations or to obtain adequate financing to fund our capital expenditures and meet working capital needs; negative events or publicity adversely affecting our ability to maintain our relationships with our suppliers, service providers, customers, employees, and other third parties; plans, objectives, expectations and intentions contained in this press release that are not historical; our ability to execute our business plan in volatile and depressed commodity price environments; any decline in and volatility of commodity prices for oil, NGLs, and natural gas; our anticipated production and development results; 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; our ability to contract for drilling rigs, frac crews, 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 that estimated in our proved oil and natural gas reserves; drilling and operating risks; concentration of assets; our ability to compete effectively against other oil and gas companies; leasehold terms expiring before production can be established and our ability to replace expired leases; costs or results of any strategic initiatives; environmental obligations, results of new drilling activities, locations and methods, costs and liabilities that are not covered by an effective indemnity or insurance; the timing of receipt of necessary regulatory permits; the effect of commodity and financial derivative arrangements; the occurrence of unusual weather or operating conditions, including force majeure events and hurricanes; our ability to retain or attract senior management and key employees; potential adverse effects of the completed bankruptcy proceedings on our liquidity, results of operations, business prospects, ability to retain financing and other risks and uncertainties related to our emergence from bankruptcy; our post-bankruptcy capital structure and the adoption of fresh start accounting, including the risk that assumptions and factors used in estimated enterprise value vary significantly from the current estimates in connection with the application of fresh start accounting; 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; litigation that impacts us, our assets or our midstream service providers; uncertainties relating to general domestic and international economic and political conditions; and other risks set forth in our filings with the SEC. Additional information concerning these and other factors can be found in our press releases and public 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. The statements in this release speak only as of the date of this release. 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.

Oil and Gas Reserves

Statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Investors are urged to consider closely the disclosure in Penn Virginia’s Annual Report on Form 10-K for the fiscal year ended December 31, 2017 on its website at www.pennvirginia.com under Investors – SEC Filings. You can also obtain these reports from the SEC’s website at www.sec.gov.

Definitions

Proved reserves are those quantities of oil and gas which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves, but which are as likely than not to be recoverable (there should be at least a 50% probability that the quantities actually recovered will equal or exceed the proved plus probable reserve estimates). Possible reserves are those additional reserves that are less certain to be recoverable than probable reserves (there should be at least a 10% probability that the total quantities actually recovered will equal or exceed the proved plus probable plus possible reserve estimates). Estimated ultimate recovery (EUR) is the sum of reserves remaining as of a given date and cumulative production as of that date. EUR is a measure that by its nature is more speculative than estimates of reserves prepared in accordance with SEC definitions and guidelines and accordingly is less certain.

Cautionary Statements

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that a company anticipates as of a given date to be economically and legally producible and deliverable by application of development projects to known accumulations. We use certain terms in this presentation, such as total resource potential, that the SEC's rules strictly prohibit us from including in filings with the SEC. These measures are by their nature more speculative than estimates of reserves prepared in accordance with SEC definitions and guidelines and accordingly are less certain. We also note that the SEC strictly prohibits us from aggregating proved, probable and possible reserves (3P) in filings with the SEC due to the different levels of certainty associated with each reserve category. The estimates and guidance presented in this release are based on assumptions of capital expenditure levels, prices for oil, natural gas and NGLs, current indications of supply and demand for oil, well results and operating costs. IP-24 production results might not be indicative of production over longer periods in the life of the well. Data regarding acreage that is expected to be acquired is based on currently available information about such acreage, including reserves and production, that was provided to us by third parties. The guidance provided in this presentation does not constitute any form of guarantee or assurance that the matters indicated will be achieved. While we believe these estimates and the assumptions on which they are based are reasonable, they are inherently uncertain and are subject to, among other things, significant business, economic, operational and regulatory risks and uncertainties and are subject to material revision. Actual results may differ materially from estimates and guidance.

Reconciliation of Non-GAAP Financial Measures

This presentation contains references to certain non-GAAP financial measures. Reconciliations between GAAP and non-GAAP financial measures are available in the appendix to this presentation. The non-GAAP financial measures presented may not provide information that is directly comparable to that provided by other companies, as other companies may calculate such financial results differently. The Company's non-GAAP financial measures are not measurements of financial performance under GAAP and should not be considered as alternatives to amounts presented in accordance with GAAP. The Company views these non-GAAP financial measures as supplemental and they are not intended to be a substitute for, or superior to, the information provided by GAAP financial results.

Company Overview

Pure Play Eagle Ford Shale Operator

- ~83,100[2] net acres in Gonzales, Lavaca and Dewitt Counties
- ~93% HBP with high-percentage oil and robust EBITDAX margins
- 2018 Production Guidance: Targeting Y-o-Y production growth of ~125%[4] with current development program
  - 22,000 – 25,000 BOEPD
- Substantial Eagle Ford inventory ~589 gross locations (~500 net)[2]
  - Area 1: ~278 net; Area 2: ~222 net
  - 99% operated
  - Includes 80 net extended reach laterals (XLRs), of ~8,000' or greater
- Active 3-rig program

Financial & Operational Profile

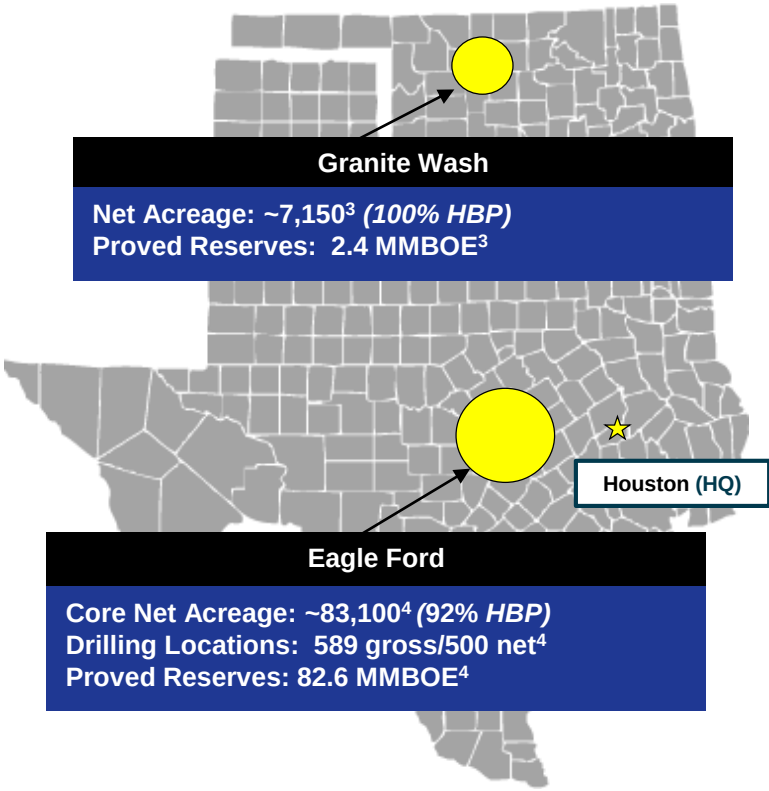
Exchange: Ticker	NASDAQ: PVAC
Share Price [1]	$37.30
Shares Outstanding (MM) as 12/31/2017	15.0
Market Capitalization ($ MM) [1]	$560
Long Term Debt ($ MM) [2]	$375
Enterprise Value ($ MM)	$935
Avg. 4Q Daily Production (BOEPD)	12,340 (74% oil)
2017 Exit Rate (average of last five days) Daily Production (BOEPD)	~14,650
PV-10 PDP at Strip Pricing ($ MM) [3]	$556
PV-10 Total Proved at Strip Pricing ($ MM) [3]	$823
Proved Reserves (MMBOE) [2]	76
Proved Reserves (Pro forma for Hunt Acquisition (MMBOE) [2]	85

1) As of February 28, 2018.
2) As of December 31, 2017, pro forma for Hunt acquisition.
3) PV-10 is a non-GAAP measure reconciled to Standardized Measure in the Appendix of this presentation, pro forma for Hunt acquisition.
4) Assumes mid-point of 2018 production guidance.

Strong Operational Performance

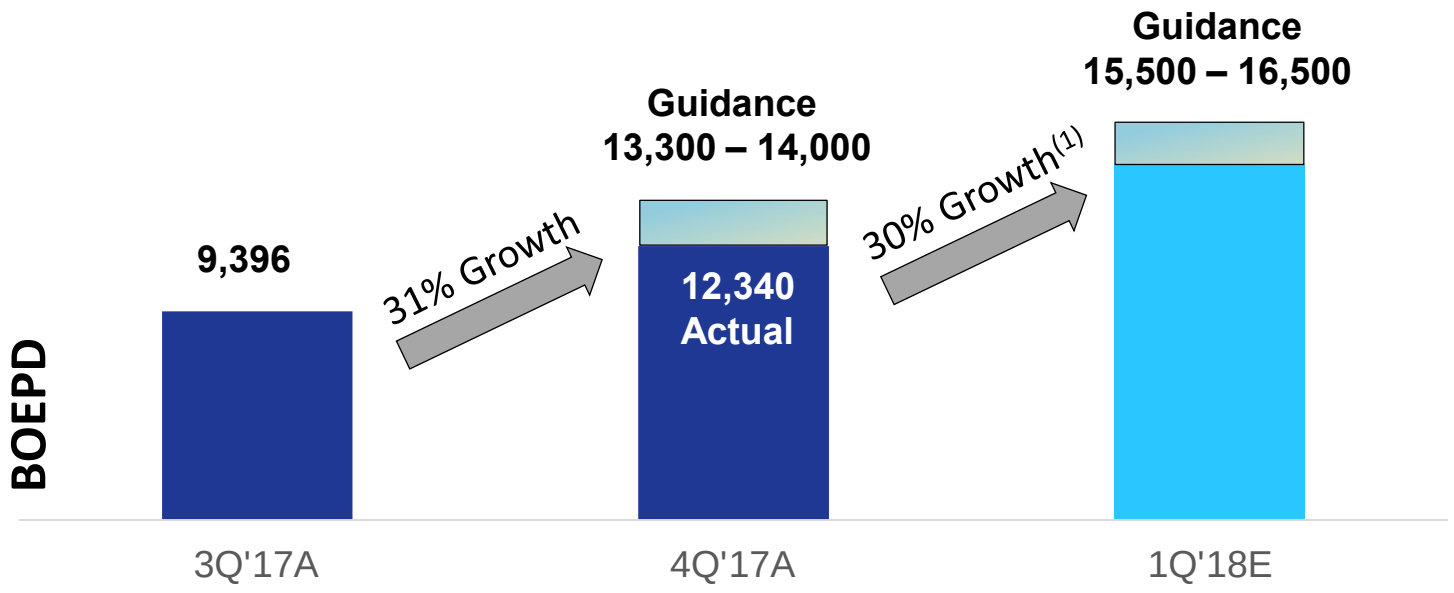
Fourth Quarter 2017, Full-Year 2017 and Recent Highlights

- Strong well results continue in Area 2 with Geo-Hunter and Southern Hunter-Amber pads
- Expanded technical team and upgraded drilling and completion equipment delivering significant improvements
- Targeting ~125%[1] production growth Y-O-Y for 2018
- 4th Qtr. 2017 production increased 31% over 3rd Qtr. 2017; Increased proved reserves by 47%; replaced ~710% of 2017 production at a drill-bit F&D cost of $4.40/BOE[2]
- Closed previously announced acquisition of Eagle Ford assets from Hunt Oil Company on March 1, 2018.
- Increased borrowing base under the credit facility by more than 40% to $340 MM, effective March 1, 2018



1) Assumes mid-point of 2018 production guidance.
2) For an explanation of these supplemental measures, see the section titled "Reserve Replacement Ratio and Drill-bit Finding and Development - Definition" at the end of this presentation.
3) As of December 31, 2017.
4) As of December 31, 2017, pro forma for Hunt acquisition.

Significant Production Growth



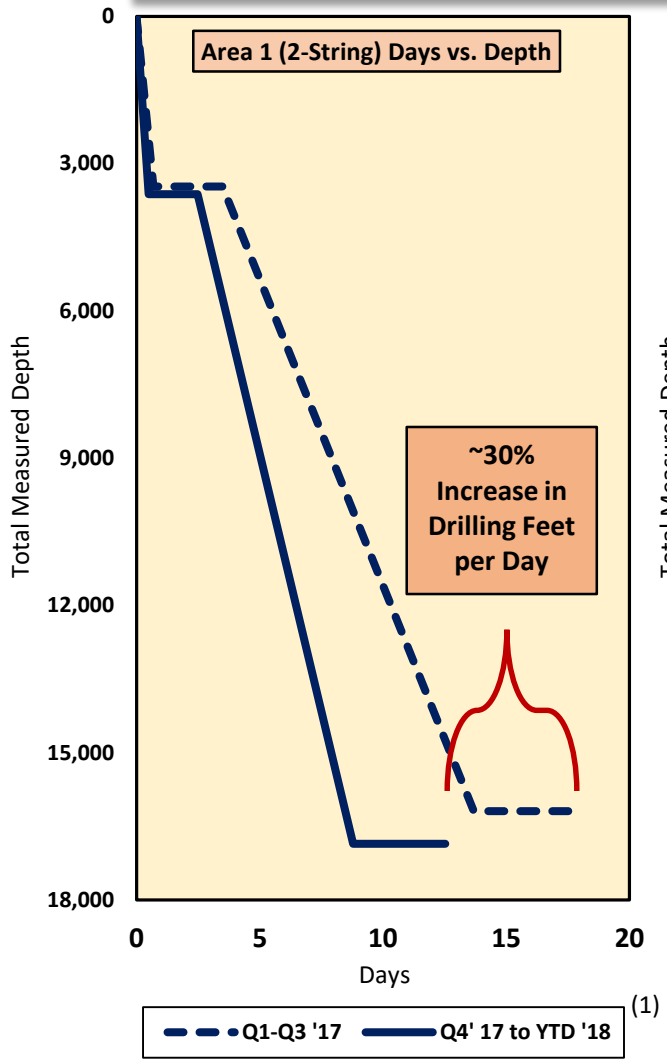
- **Strong well results in Area 2**
  - Geo Hunter pad had a a 24-hour IP rate of 5,465 BOEPD and 30-day IP rate of 3,767 BOEPD, turned to sales late December.
  - Southern Hunter Amber had a Preliminary 24-hour IP rate from its pad of 5,092 BOEPD, turned to sales mid-February
- **Drilling Challenges in Second Half of 2017 Yielded Shorter Laterals That Under-Performed Expectations**
- **Delays Shifted Geo Hunter & Furrh Pads First Sales to Late December 2017 and January 2018**

1) Assumes mid-point of 1Q 2018 production guidance.

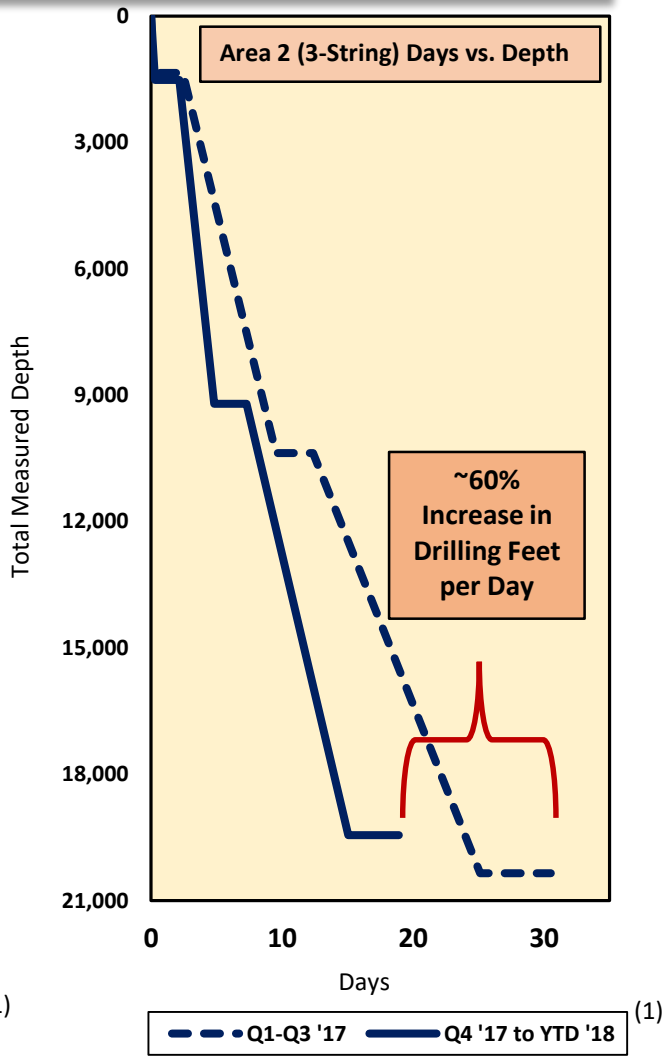
Improved Operational Efficiency

Expanded Technical Team & Upgraded Equipment Driving Improved Operational Execution

Increased Drilling Efficiency – Avg. Feet / Day from Spud-to-Rig Release

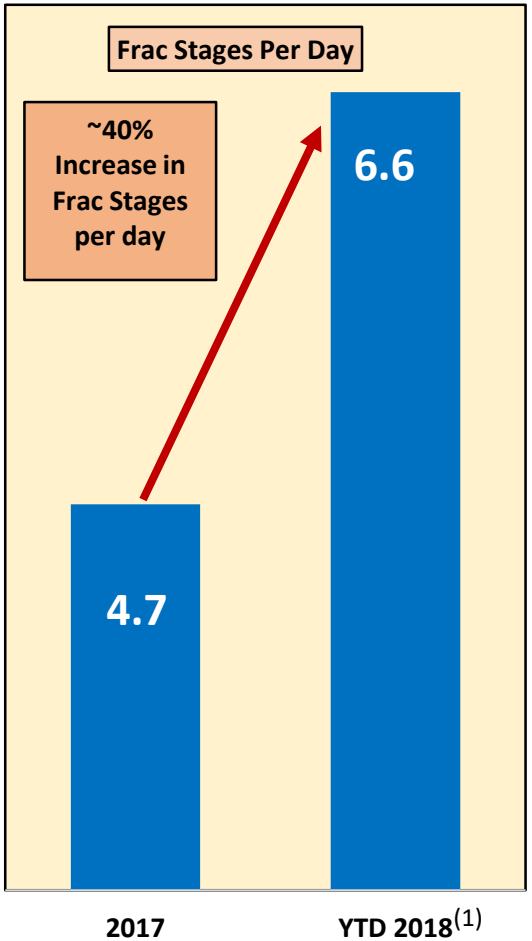


(1)



(1)

Increased Completion Efficiency

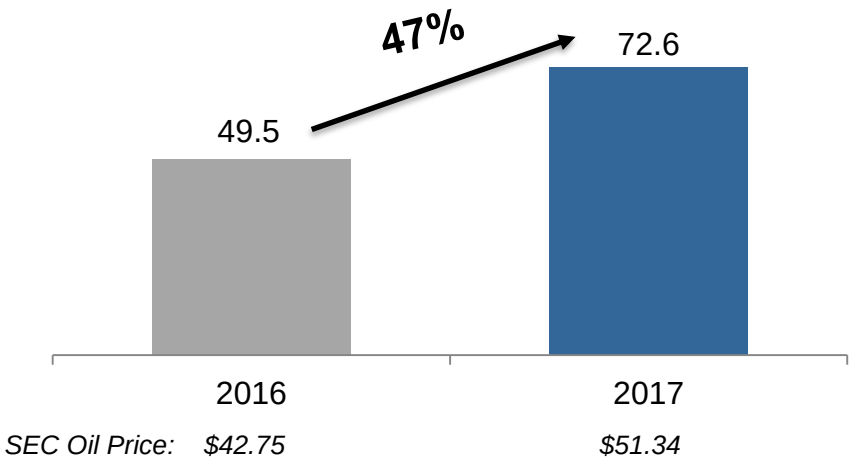


1) Through 02/28/2018.

Year-End 2017 Proved Reserves (excludes Hunt acquisition)

47% Increase in Proved Reserves

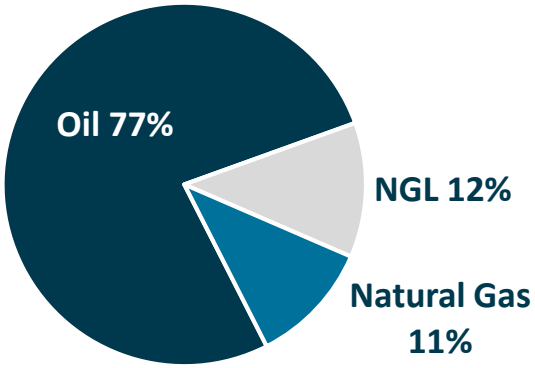
Proved Reserves (MMBOE) Growth

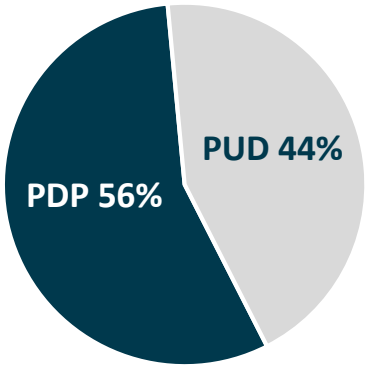


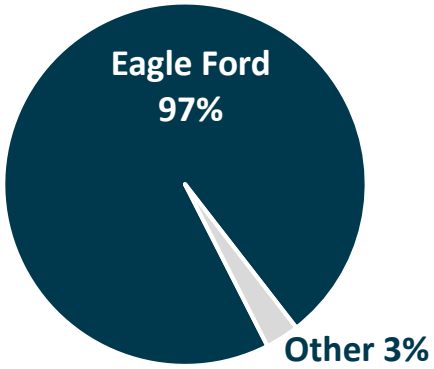
2017 Year-End Reserves Highlights

- Standardized Measure / PV-10 value with SEC pricing of $590 million and $609 million, respectively[1]
- PV-10 valued at strip pricing of $632 million, with $460 million provided by PDP reserves [2]
- Replaced 710% of 2017 production at drill-bit F&D of ~$4.40 per BOE [3]

2017 Year-End Reserves Composition and Location



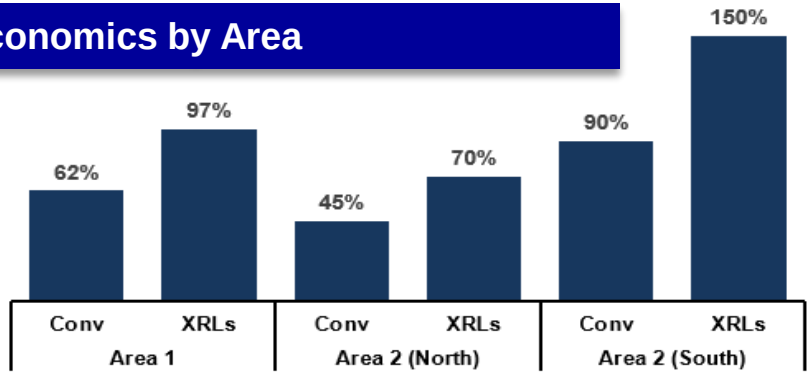




1) PV-10 is a non-GAAP measure reconciled to GAAP Standardized Measure in the Appendix of the presentation.
2) Monthly NYMEX pricing as of closing on December 31, 2017. See Appendix for pricing. Proved reserves were not changed for the change in pricing.
3) For an explanation of these supplemental measures, see the section titled "Reserve Replacement Ratio and Drill-bit Finding and Development - Definition" at the end of this presentation.

Large Inventory of Locations With Attractive Returns

Eagle Ford Economics by Area



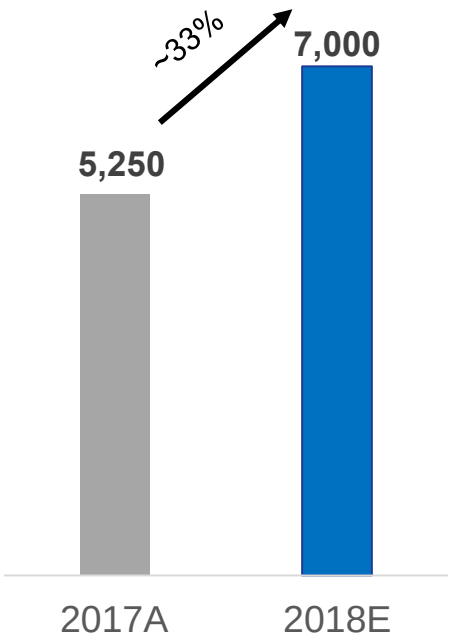
	Area 1 Conv	Area 1 XRLs	Area 2 (North) Conv	Area 2 (North) XRLs	Area 2 (South) Conv	Area 2 (South) XRLs
Producing Wells	227	-	75	-	71	2
Drilling Locations	307	26	144	41	38	33
EUR (Mboe)	485	710	620	920	1,120	1,865
% Oil	87%	87%	70%	70%	41%	41%
% NGL	7%	7%	16%	16%	33%	33%
% Gas	6%	6%	13%	13%	26%	26%
EUR per foot (boe)	81	81	100	100	187	187
Lateral Length	6,000	8,800	6,200	9,200	6,000	10,000
Well Cost (MM$)	5.3	6.6	6.6	8.3	6.5	8.8
PV10 BTAX (MM$)	4.1	7.4	3.8	7.2	6.8	13.5
ROR BTAX (%)	62%	97%	45%	70%	90%	150%
Payout (Yrs)	1.3	1.0	1.6	1.2	1.0	0.7

Note: Based on management's internal estimates as of February 14, 2018; economics based of $56 WTI and $3 natural gas. Drilling locations as of December 31, 2017.

2018 Capital Plan

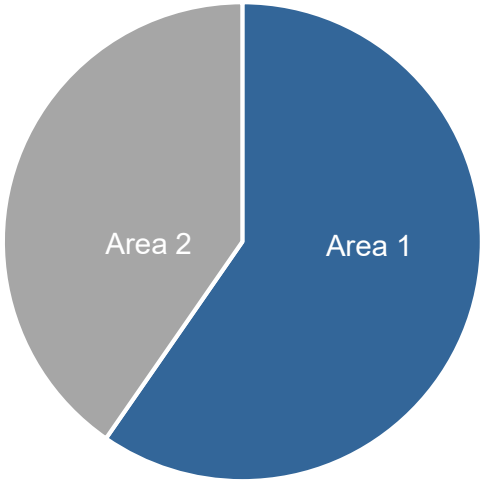
- **Estimated Capital Expenditures: Between $320 and $360 Million**
- **95% of Capital Expected to be Directed to D&C in Eagle Ford**
- **Expected to Drill a Total of 55 to 60 Gross Wells (45 to 50 net wells) (22 gross XRLs)**
  - **Area 1 - 33 to 35 Gross Wells (26 to 28 Net Wells)**
  - **Area 2 - 22 to 25 Gross Wells (19 to 22 Net Wells)**

Average Treatable Lateral Length

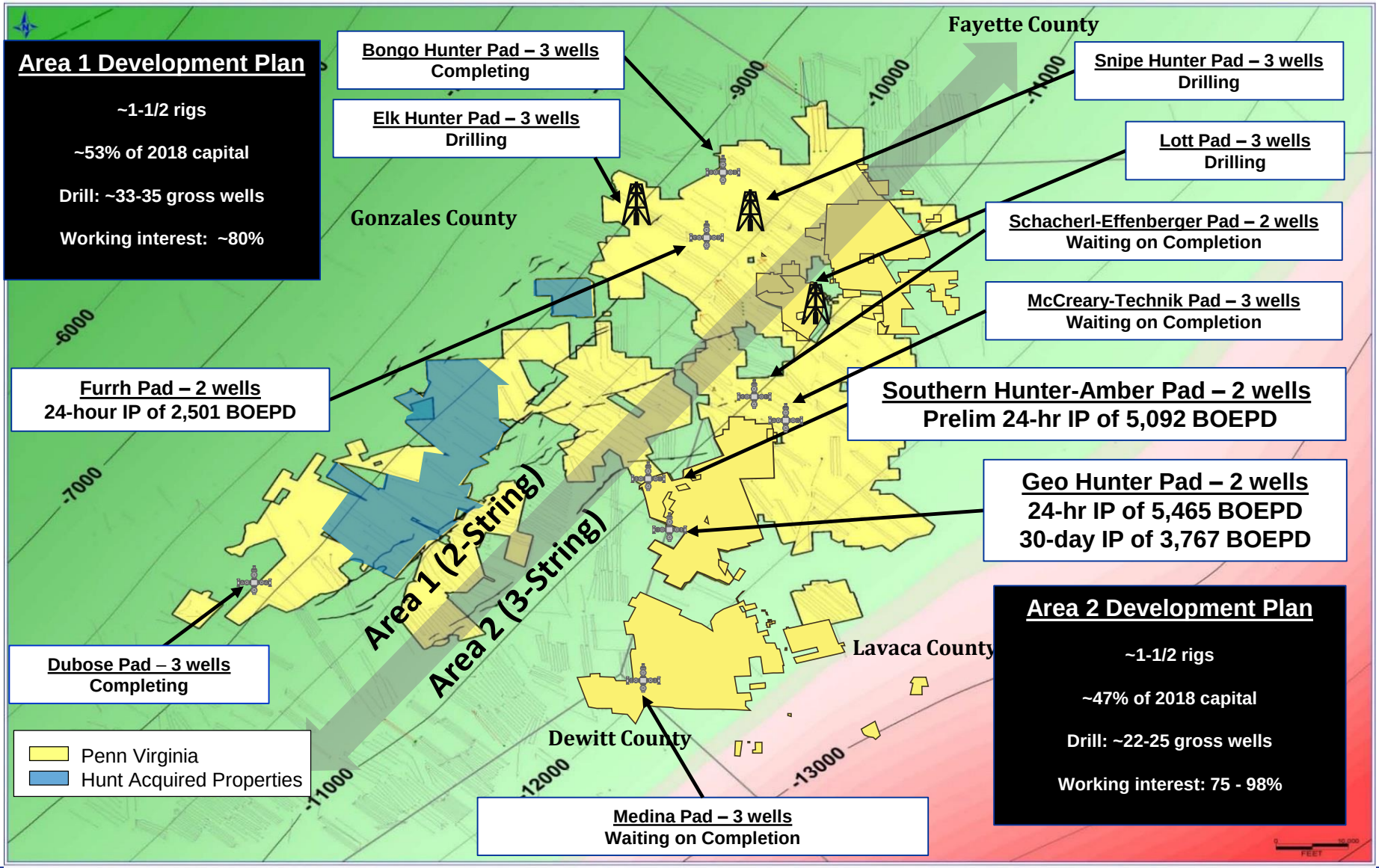


Capital by Area

Wells By Area



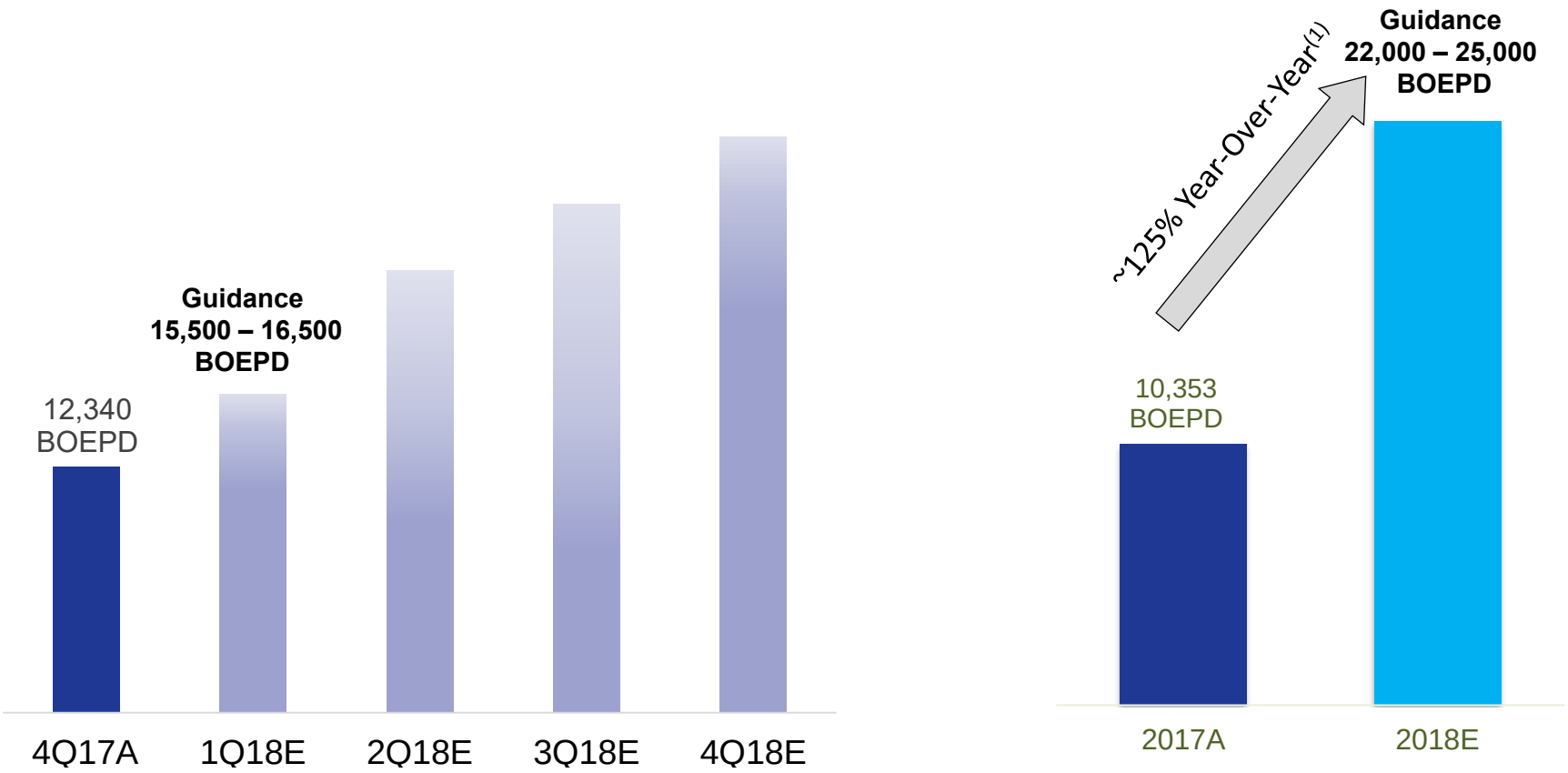
2018 Development Plans



Production Growth

Targeting ~125% Year-Over-Year Production Growth

Increasing Production ~125% Y-O-Y → Lower Operating Cost per BOE → Increasing Adjusted EBITDAX per BOE → Lowers Leverage Metric

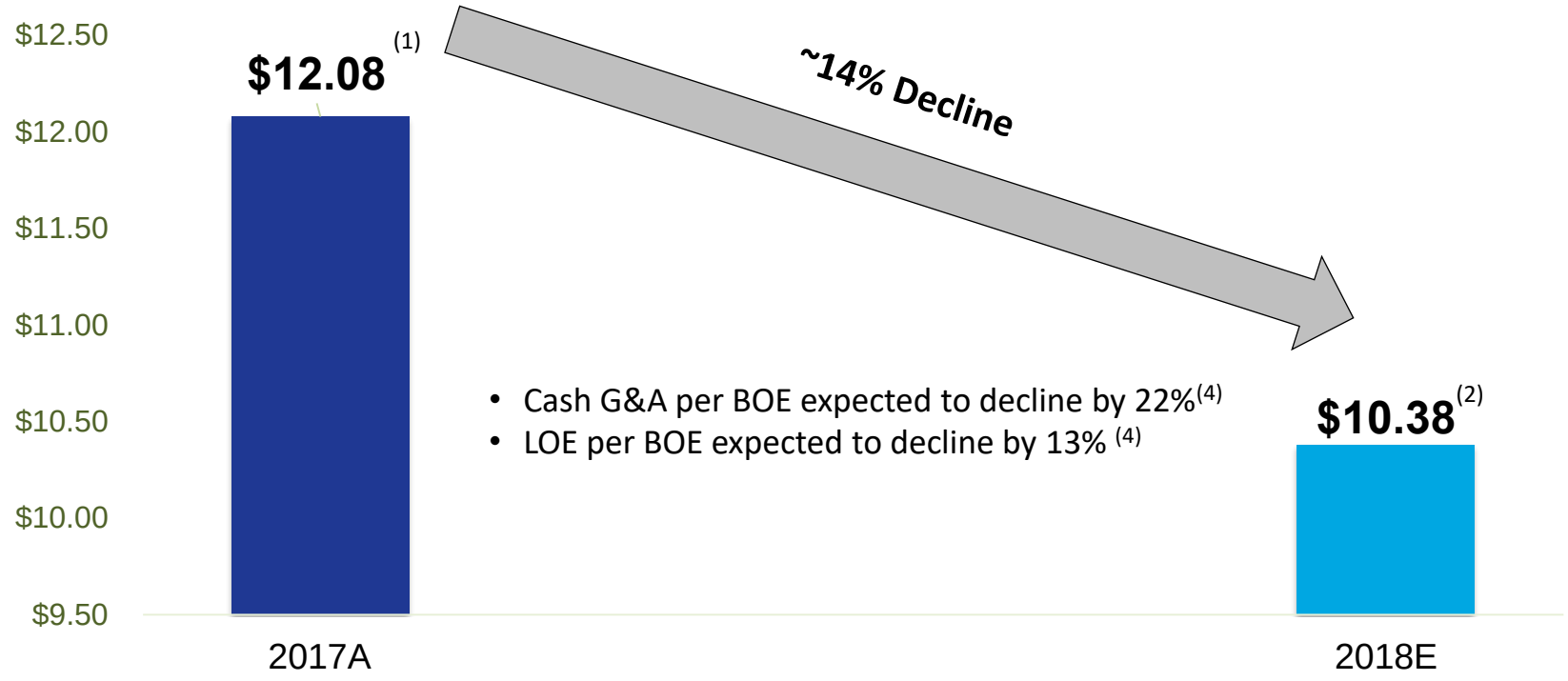


2018 Production Growth to Drive Cost per BOE Down

Note: Graphical representation of production growth profile only – Not intended to be quarterly guidance. Not to scale.
1) Assumes mid-point of 2018 production guidance.

Declining Cash Cost per BOE

Increasing Production ~125% Y-O-Y → **Lower Operating Cost per BOE** → Increasing Adjusted EBITDAX per BOE → Lowers Leverage Metric



- Cash G&A per BOE expected to decline by 22%(4)
- LOE per BOE expected to decline by 13% (4)

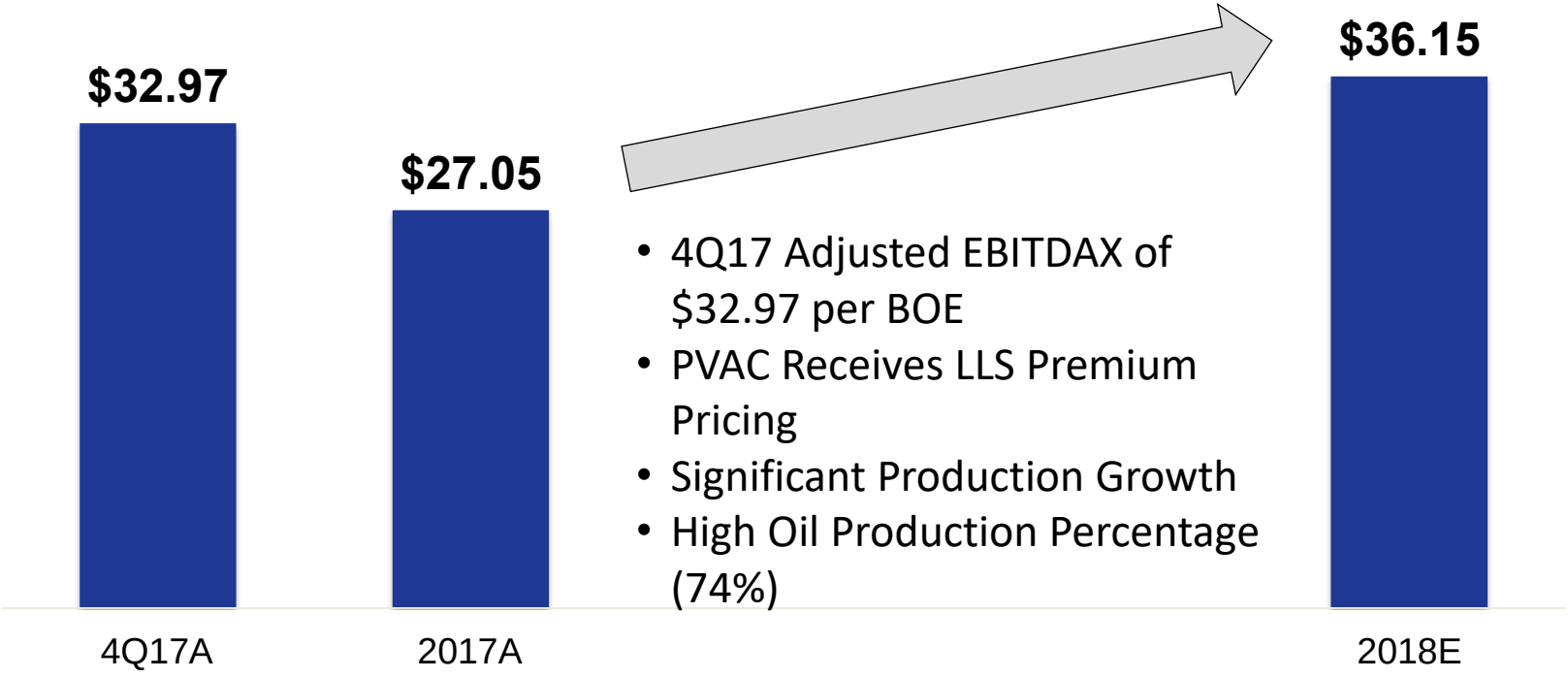
2018 Cash Cost per BOE Expected to Decrease Significantly by Year-end

1) 2017A Cash Cost per BOE is comprised of the sum of (Lease Operating Expense ($5.76/BOE) + GPT Expense ($2.84/BOE) + Adjusted Cash G&A(3) ($3.48/BOE)) divided by actual 2017 production).
2) 2018E Cash Cost per BOE is comprised of the sum of mid-point of guidance of (Lease Operating Expense + GPT Expense + Cash G&A Expense), which can be found in the Appendix of this presentation.
3) Adjusted Cash G&A is a non-GAAP financial measure. Definitions of non-GAAP financial measures and reconciliations of non-GAAP financial measures to the closest GAAP-based financial measures appear at the end of this presentation.
4) Based on mid-point of guidance

Adjusted EBITDAX per BOE [1]

Increasing Production ~125% Y-O-Y → Lower Operating Cost per BOE → **Increasing Adjusted EBITDAX per BOE** → Lowers Leverage Metric

Adjusted EBITDAX per BOE Accelerates Throughout 2018



- 4Q17 Adjusted EBITDAX of $32.97 per BOE
- PVAC Receives LLS Premium Pricing
- Significant Production Growth
- High Oil Production Percentage (74%)

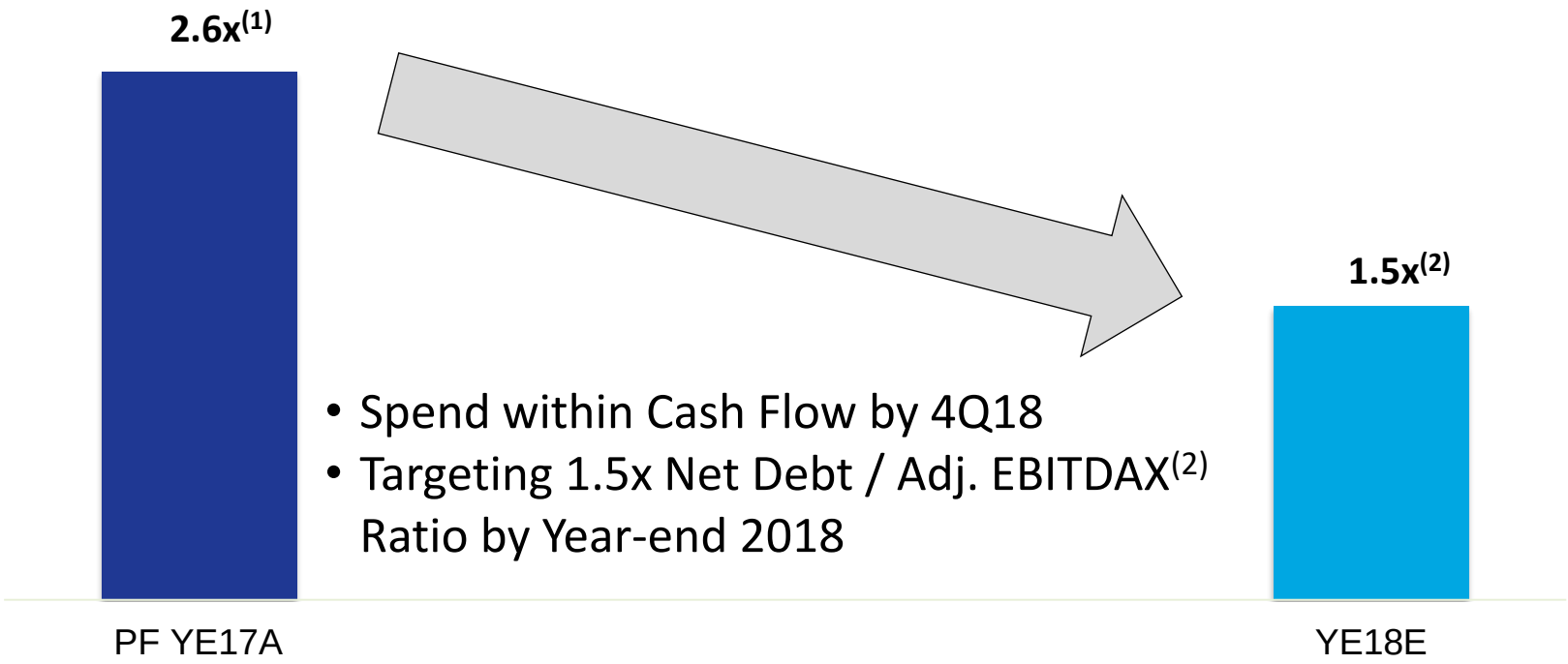
1) Adjusted EBITDAX per BOE is a non-GAAP measure. See appendix for explanation of these non-GAAP calculations

Balance Sheet Improvement

Debt to Adjusted EBITDAX

Increasing Production ~125% Y-O-Y → Lower Operating Cost per BOE → Increasing Adjusted EBITDAX per BOE → Lowers Leverage Metric

Strong Cash Flow Growth Rapidly Improves Balance Sheet

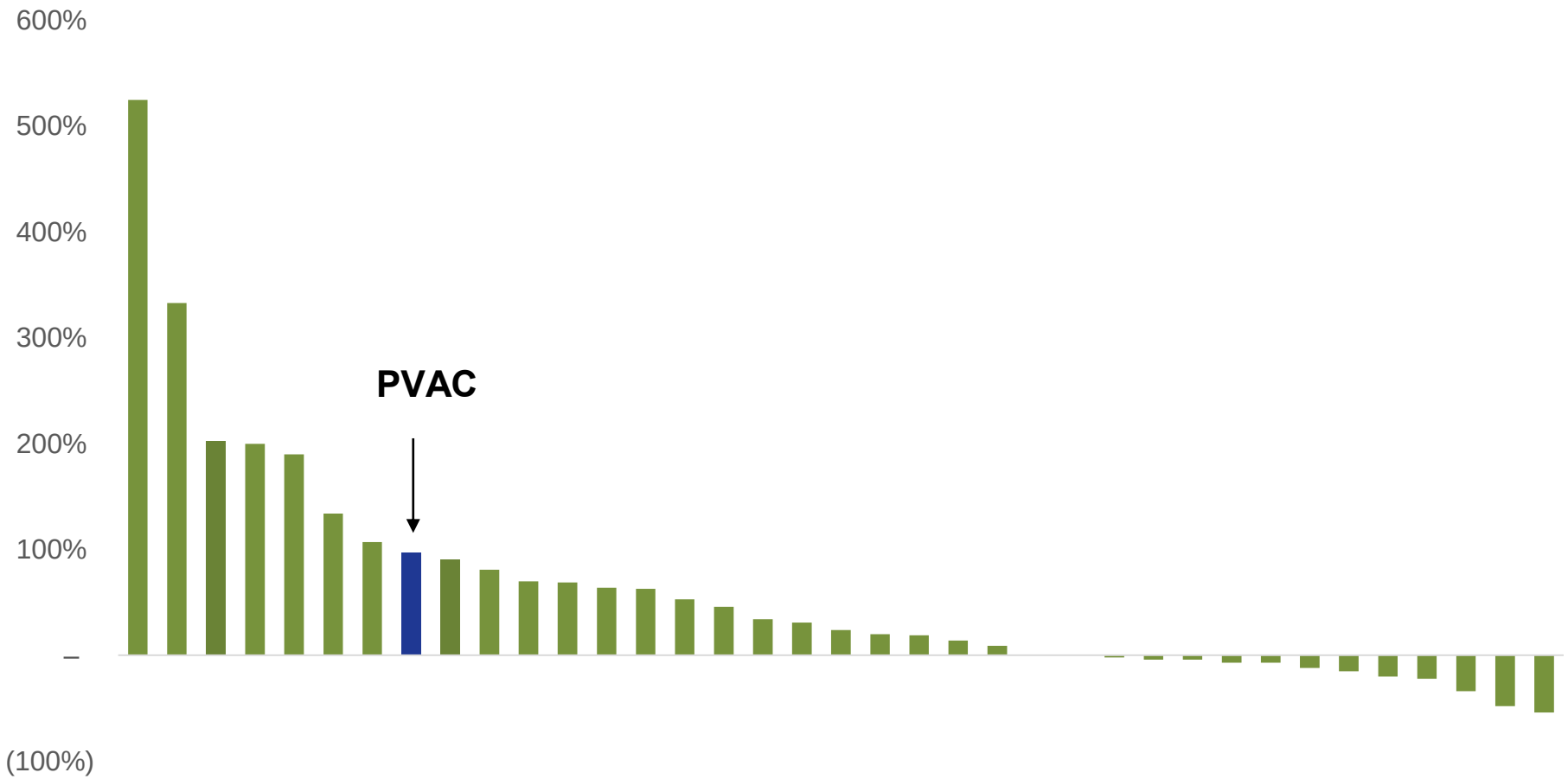


- Spend within Cash Flow by 4Q18
- Targeting 1.5x Net Debt / Adj. EBITDAX(2) Ratio by Year-end 2018

1) Pro forma for Hunt Acquisition (2017 year-end net debt / Adjusted EBITDAX was 2.3x).
2) As defined in the Company's credit facility.

PVAC vs. Peers: % of Reserves Oil & Production Growth Rate

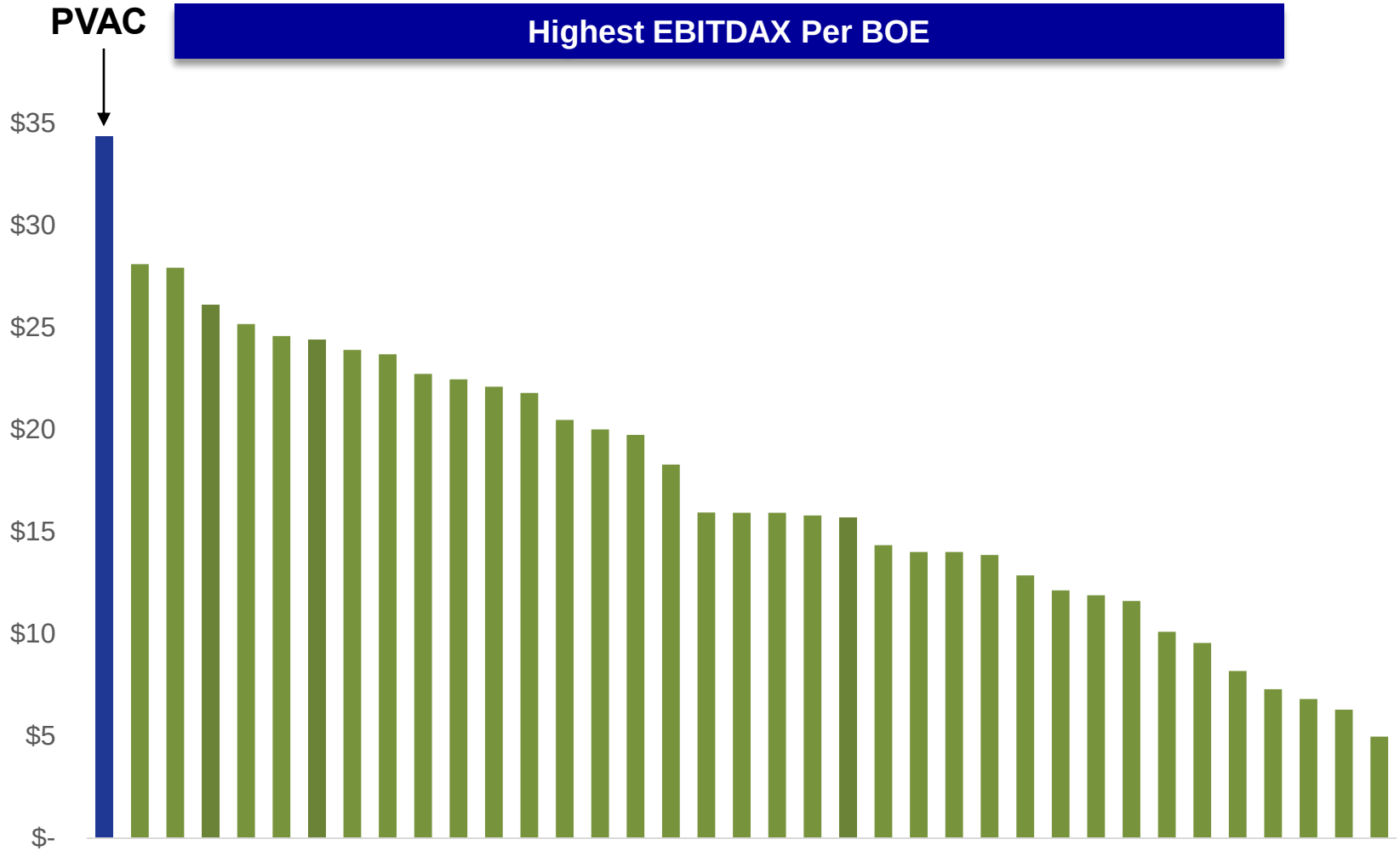
One of the Highest Production Growth Rates - 2018 over 2017 (1)



Disclaimer: Data is based on the arithmetic average of all consensus estimates publicly available at the time of publication of the consensus figures on FactSet. Any opinions, forecasts, estimates, projections or predictions regarding Penn Virginia's performance and its peers made by the analysts, and thereby also the consensus estimates, are theirs alone and do not in any way represent the opinions, forecasts, estimates, projections or predictions of Penn Virginia or its management. In providing these consensus figures, Penn Virginia does not imply its endorsement of, or concurrence with, such information. The consensus figures are provided for information purposes only and should not be relied upon in making an investment decision.

Note: Peer Group Companies include: AREX, BBG, BCEI, CHK, CPE, CRC, CRK, DNR, ECR, EPE, ESTE, GPOR, GST, HK, JAG, JONE, LONE, LPI, MCF, NOG, OAS, PQ, QEP, REN, REXX, SBOW, SD, SGY, SM, SN, SRCI, SWN, UPL, WLL, WRD and XOG.
Source: RBC; Market data based on public information available as of 2/9/2018.
1) 2018 projected growth rate over 2017

PVAC vs. Peers: 2018 EBITDAX / BOE

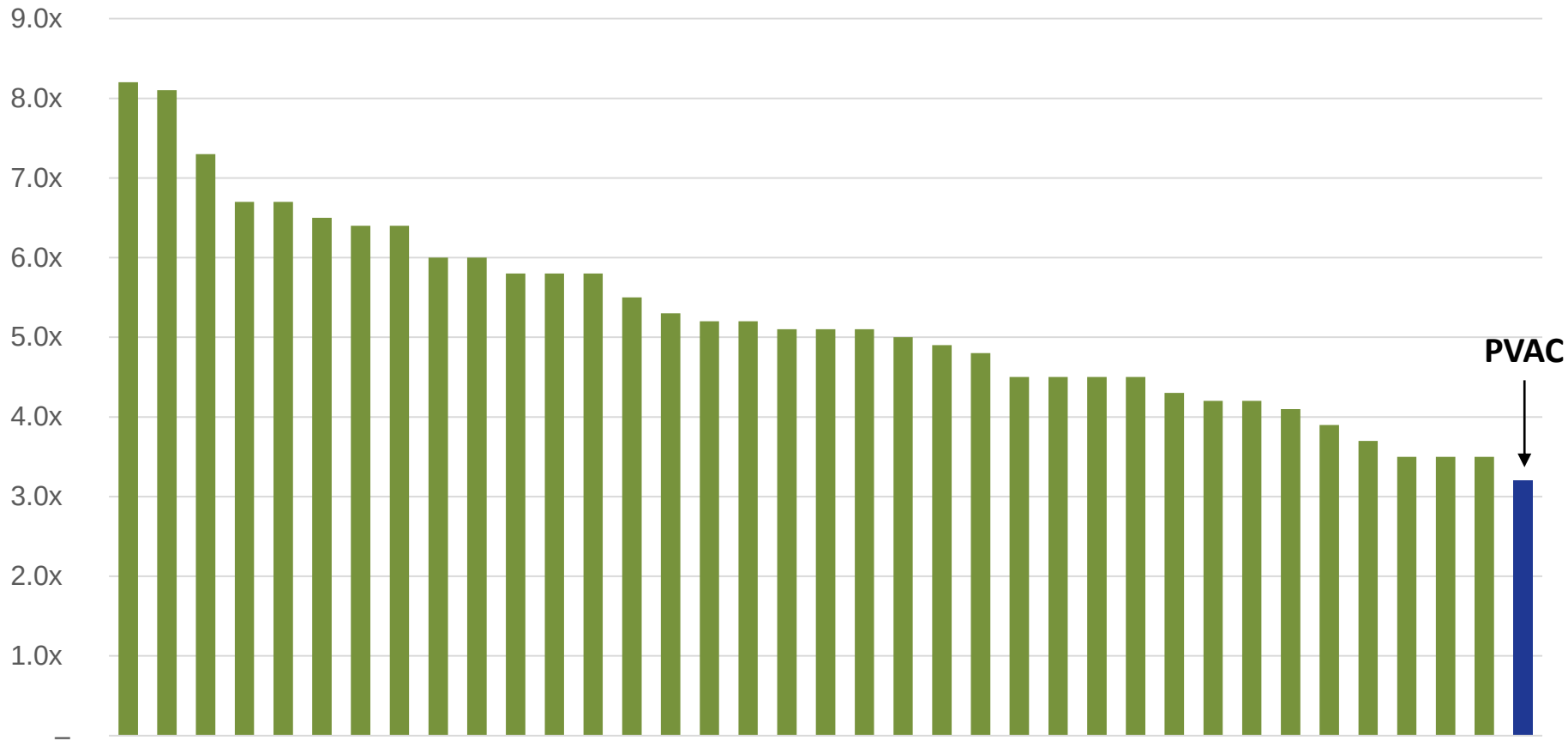


Disclaimer: Data is based on the arithmetic average of all consensus estimates publicly available at the time of publication of the consensus figures on FactSet. Any opinions, forecasts, estimates, projections or predictions regarding Penn Virginia's performance and its peers made by the analysts, and thereby also the consensus estimates, are theirs alone and do not in any way represent the opinions, forecasts, estimates, projections or predictions of Penn Virginia or its management. In providing these consensus figures, Penn Virginia does not imply its endorsement of, or concurrence with, such information. The consensus figures are provided for information purposes only and should not be relied upon in making an investment decision.

Note: Peer Group Companies include: AREX, BBG, BCEI, CHK, CPE, CRC, CRK, DNR, ECR, EPE, ESTE, GPOR, GST, JAG, JONE, LLEX, LONE, LPI, MCF, NOG, OAS, PQ, QEP, REN, REXX, SBOW, SD, SGY, SM, SN, SRCI, SWN, UPL, WLL, WRD and XOG.
Source: RBC; Market data based on public information available as of 2/9/2018.

PVAC vs. Peers: TEV / 2018 EBITDAX

Lowest EBITDAX Multiple in Small/Mid-Cap E&P Sector



Disclaimer: Data is based on the arithmetic average of all consensus estimates publicly available at the time of publication of the consensus figures on FactSet. Any opinions, forecasts, estimates, projections or predictions regarding Penn Virginia's performance and its peers made by the analysts, and thereby also the consensus estimates, are theirs alone and do not in any way represent the opinions, forecasts, estimates, projections or predictions of Penn Virginia or its management. In providing these consensus figures, Penn Virginia does not imply its endorsement of, or concurrence with, such information. The consensus figures are provided for information purposes only and should not be relied upon in making an investment decision.

Note: Peer Group Companies include: AREX, BBG, BCEI, CHK, CPE, CRC, CRK, DNR, ECR, EPE, ESTE, GPOR, HK, JAG, JONE, LLEX, LONE, LPI, MCF, NOG, OAS, PQ, QEP, REN, REXX, SBOW, SD, SGY, SM, SN, SRCI, SWN, UPL, WLL, WRD and XOG.
Source: RBC Market data based on public information available as of 2/9/2018.

Why Penn Virginia?

Pure Play

- "Pure play" Eagle Ford company
- Contiguous Eagle Ford acreage position of ~83,100 net acres [1]
- Focused on returns: Well returns anticipated to be 45% to 150%

Quality Assets

- Situated in "volatile" oil window
- Heavily weighted oil portfolio; 87% liquids (73% crude oil)
- Strong realized pricing yields robust EBITDAX margins

Financial Discipline

- Strong balance sheet and ample liquidity
- Expect to spend within cash flow by 4Q 2018; Targeting 1.5x net debt / Adjusted EBITDAX
- Approximately 50% of oil hedged in 2018

Growth Potential

- Estimated 2018 production growth: ~125% [2] (Y-O-Y)
- Multi-year drilling inventory with superior economics
- Inventory upside from Upper Eagle Ford and Austin Chalk

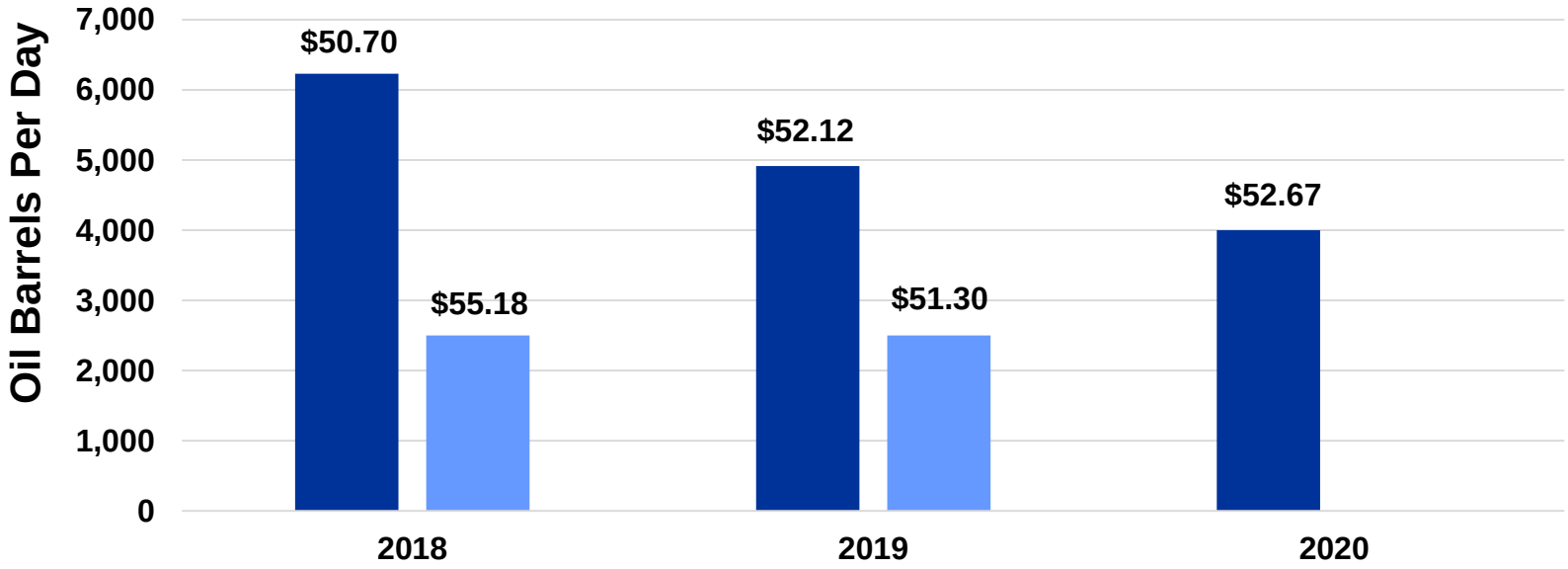
1) As of December 31, 2017, pro forma for Hunt acquisition
2) Based on mid-point of guidance

PENN VIRGINIA CORPORATION

Appendix

Updated Hedge Portfolio [1]

Mitigating Commodity Price Volatility Through Proactive Hedging Program



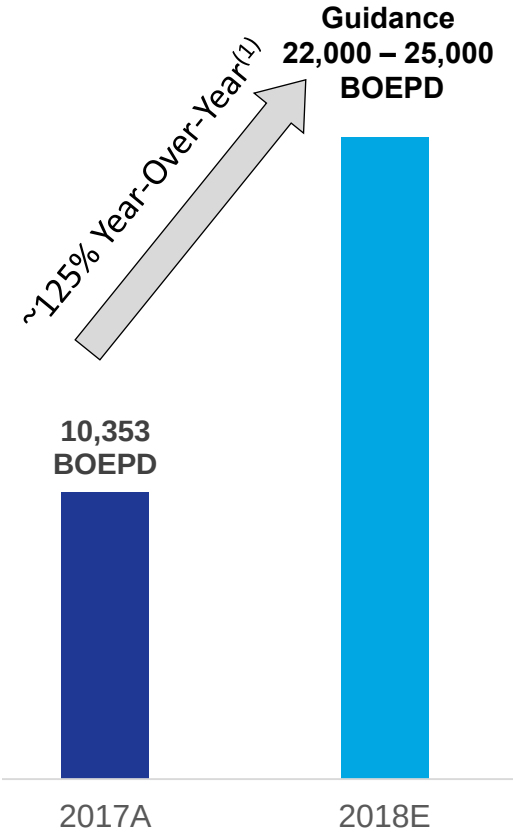
	WTI Volumes *(Bbls / Day)*	**WTI** Average Price *($ / Bbl)*	**LLS** Volumes *(Bbls / Day)*	**LLS** Average Price *($ / Barrel)*
2018	6,227	$50.70	2,500	$55.18
2019	4,915	$52.12	2,500	$51.30
2020	4,000	$52.67	-	-

1) As of 02/13/2018.

Updated Guidance

The table below sets forth the Company's current financial and operational guidance for 2018:

	2018	
Production (BOEPD)		**% oil**
First Quarter	15,500 – 16,500	74%
Full Year	22,000 – 25,000	74%
Realized Price Differentials		
Oil (off WTI, per barrel)	$1.00 - $2.00	
Natural gas (off Henry Hub, per MMBtu)	$0.10 - $0.20	
Direct Operating Expenses		
Lease operating expense (per BOE)	$4.75 - $5.25	
GPT expense (per BOE)	$2.75 - $3.00	
Ad valorem and production taxes (percent of product revenue)	5.5% - 6.0%	
Cash G&A expense (per BOE)	$2.25 - $2.75	
Capital Expenditures (millions)	$320 - $360	



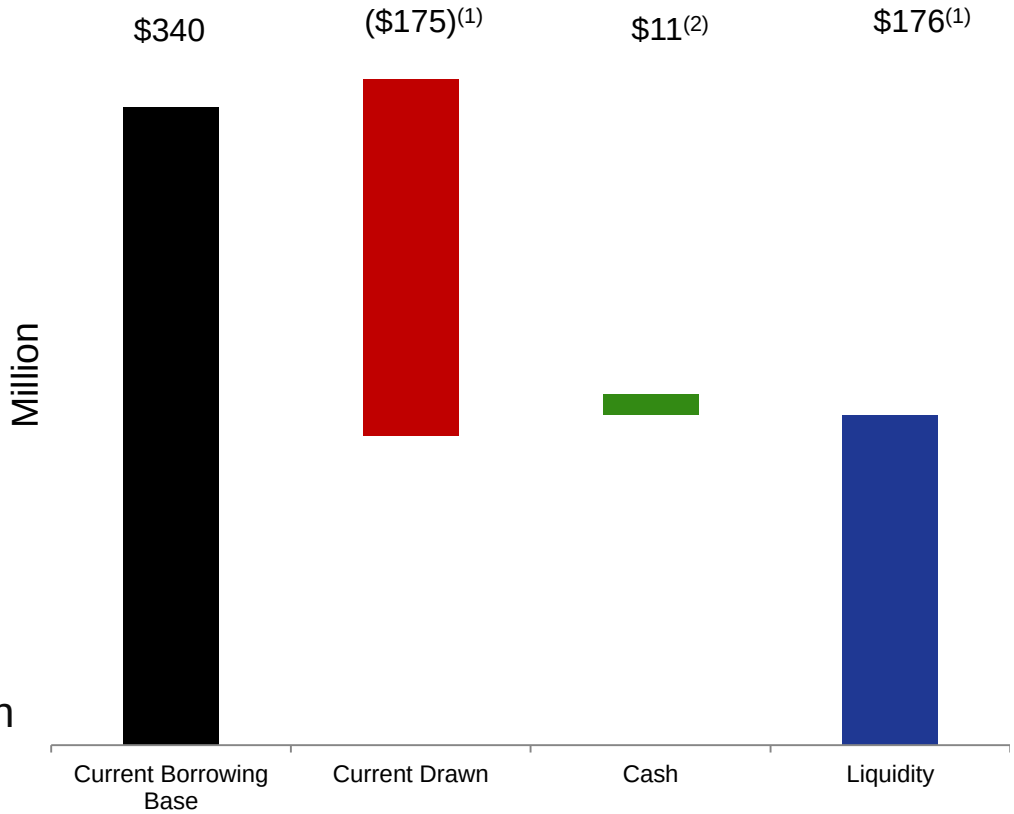
- **Expected to Drill a Total of 55 to 60 Gross Wells (45 to 50 Net Wells) (22 Gross XRLs)**
  - **Area 1 - 33 to 35 Gross Wells (26 to 28 Net Wells)**
  - **Area 2 - 22 to 25 Gross Wells (19 to 22 Net Wells)**

1) Assumes mid-point of 2018 production guidance.

Balance Sheet and Liquidity

- **Increased borrowing base under the credit facility by more than 40% to $340 MM, effective March 1, 2018**
  - Borrowing base increase exceeds the Hunt acquisition, improving liquidity
- **Pro Forma Liquidity of ~$176 MM [1]**
- **Restoring Low Leverage**
  - Target net debt to Adjusted EBITDAX of 1.5x by end of 2018
  - Expected to live within cash flow by fourth quarter of 2018

Pro Forma Liquidity of ~$176 MM at Year-end



Preserve Strong Balance Sheet and Ample Liquidity

(1) As of March 1, 2018, post closing for the Hunt acquisition and subject to change, does not include letters of credit of $0.8 million.
(2) As December 31, 2017.

Hunt Acquisition Overview

Bolt-on Acquisition

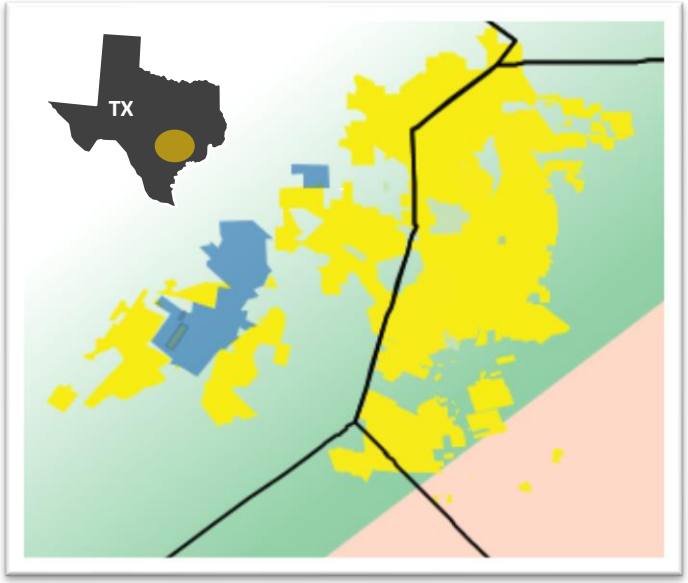
Transaction Summary

- On January 2, 2018, the Company announced a $86 MM acquisition of certain of Hunt Oil Company's ("Hunt") Eagle Ford Shale assets, primarily in Gonzales and Lavaca Counties, TX.
- Closed on March 1, 2018 with effective date of October 1, 2017.
- Funded with borrowings under the Company's credit facility.

Transaction Highlights

- Expands the Company's acreage ~13%, or 9,700 net acres in Area 1, 5,700 net acres were operated by Penn Virginia. Increases operated acreage to 99%;
- Includes production ~1,870 BOEPD[(1)] (89% oil) and 75 de-risked net lower Eagle Ford locations;
- Adds PDP reserves of approximately 3.8 MMBOE (86% oil) and ~8 MMBOE of PUDs; resource potential > 29 MMBOE;
- Provides economies of scale; increases PVAC's cash operating margin; requires minimal G&A or additional drilling rigs to capture value;
- Acquired acreage for ~$2,100 per net acre, including net production value of ~$65.5 million ($35,000 per flowing BOEPD); and
- Accretive to Penn Virginia under all measures, including earnings, cash flow and net asset value per share.

PVAC / Hunt Asset Map



Penn Virginia
Hunt

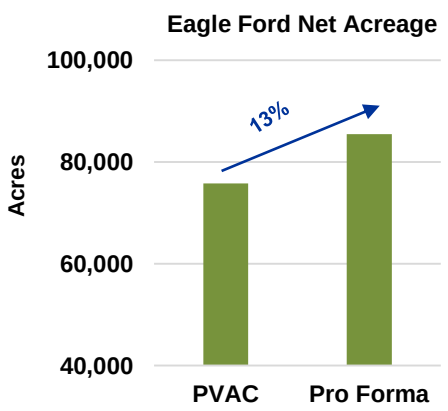
(1) Average production for the month of September 2017.

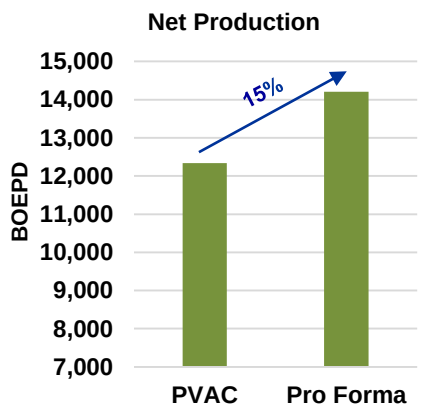
Transaction and Asset Highlights

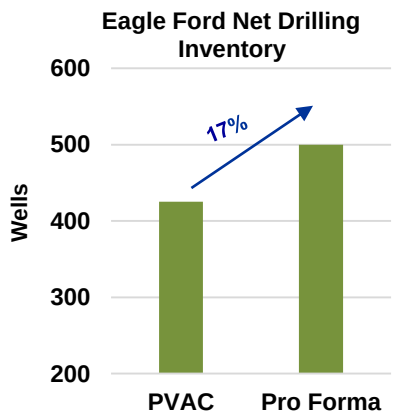
Increases Leasehold Position and Drilling Inventory By Approximately 13% and 17%, respectively

- Nearly 90% of production is crude oil, which receives premium LLS pricing.

All numbers are approximate	Pre-Acquisition Penn Virginia	Acquisition	Post-Acquisition Penn Virginia [5]	Percent Change
Net production (BOEPD)	12,340[1]	1,870[2]	14,210	15%
Oil - percent of BOEPD	74%[1]	89%[2]	76%	2%
Eagle Ford net acreage	73,400[3]	9,700	83,100	13%
Eagle Ford gross drilling inventory	589[3]	-	589	-
Eagle Ford net drilling inventory	425[3]	75	500	17%
Eagle Ford net treatable lateral length[4]	2.8 MM feet	0.5 MM feet	3.3 MM feet	16%







(1) Average production for the 4Q 2017.
(2) Average production for the month of September 2017.
(3) As of December 31, 2017.
(4) Represents total treatable lateral length in net drilling inventory.
(5) Metrics represent direct impact of acquisition as shown but does not necessarily represent the Company's results for future periods.

Non-GAAP Reconciliation – Adjusted EBITDAX - Unaudited

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

Adjusted EBITDAX represents net income (loss) before interest expense, income tax expense (benefit), depreciation, depletion and amortization expense, exploration, and share-based compensation expense, further adjusted to exclude the effects of gains and losses on sales of assets, accretion of firm transportation obligation, non-cash changes in the fair value of derivatives, and special items including acquisition transaction costs, reorganization items, strategic and financial advisory costs, restructuring expenses and account write-offs and reserves prior to our emergence from bankruptcy. We believe this presentation is commonly used by investors and professional research analysts for 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). Adjusted EBITDAX as defined by Penn Virginia may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) and other measures prepared in accordance with GAAP, such as operating income or cash flows from operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Penn Virginia's results as reported under GAAP.

In thousands, except per unit amounts	Successor Three Months Ended December 31, 2017	Successor Three Months Ended September 30, 2017	Successor Three Months Through December 31, 2016	Successor Year Ended December 31, 2017	Successor September 13 Through December 31, 2016	Predecessor January 1 Through September 12, 2016
Net income (loss)	$ (10,801)	$ (5,947)	$ (1,855)	$ 32,662	$ (5,296)	$ 1,054,602
Adjustments to reconcile to Adjusted EBITDAX:						
Interest expense, net	3,378	1,202	661	6,392	879	58,018
Income tax benefit	(4,943)	-	-	(4,943)	-	-
Depreciation, depletion and amortization	17,104	10,659	9,623	48,649	11,652	33,582
Exploration	-	-	-	-	-	10,288
Share-based compensation expense (equity-classified)	1,102	1,013	81	3,809	81	1,511
(Gain) loss on sale of assets, net	(24)	(9)	49	36	49	(1,261)
Accretion of firm transportation obligation	-	-	-	-	-	317
Adjustments for derivatives:						
Net losses (gains)	33,621	12,275	12,253	17,819	16,622	8,333
Cash settlements, net	(1,841)	788	384	(3,511)	384	48,008
Adjustment for special items:						
Acquisition transaction costs	(165)	1,505	-	1,340	-	-
Reorganization items, net	-	-	-	-	-	(1,144,993)
Strategic and financial advisory costs	-	-	-	-	-	18,036
Restructuring expenses	-	-	(116)	(20)	(98)	3,821
Account write-offs and reserves prior to emergence from bankruptcy	-	-	-	-	-	3,123
Adjusted EBITDAX	$ 37,431	$ 21,486	$ 21,080	$ 102,233	$ 24,273	$ 93,385
Adjusted EBITDAX per BOE	$ 32.97	$ 24.85	$ 24.60	$ 27.05	$ 23.35	$ 27.91

Non-GAAP Reconciliation – Adjusted Cash G&A - Unaudited

Reconciliation of GAAP "General administrative expenses" to Non-GAAP "Adjusted cash-based general and administrative expenses"

Adjusted cash-based general and administrative expense ("Adjusted G&A") is a supplemental non-GAAP financial measure that excludes certain non-recurring expenses and non-cash share-based compensation expense. We believe that the non-GAAP measure of Adjusted G&A is useful to investors because it provides readers with a meaningful measure of our recurring G&A expense and provides for greater comparability period-over-period. The table details all adjustments to G&A on a GAAP basis to arrive at Adjusted G&A.

In thousands, except per unit amounts	Successor Three Months Ended December 31, 2017	Successor Three Months Ended September 30, 2017	Successor Three Months Through December 31, 2016	Successor Year Ended December 31, 2017	Successor September 13 Through December 31, 2016	Predecessor January 1 Through September 12, 2016
General and administrative expenses - direct	$ 2,360	$ 5,939	$ 3,531	$ 14,453	$ 5,007	$ 37,434
Share-based compensation - equity-classified awards	1,102	1,013	81	3,809	81	1,511
GAAP General and administrative expenses	3,462	6,952	3,612	18,262	5,088	38,945
Less: Share-based compensation - equity-classified awards	(1,102)	(1,013)	(81)	(3,809)	(81)	(1,511)
Significant special charges:						
Acquisition transaction costs	165	(1,505)	-	(1,340)	-	-
Strategic and financial advisory costs	-	-	-	-	-	(18,036)
Restructuring expenses	-	-	116	20	98	(3,821)
Adjusted cash-based general and administrative expenses	$ 2,525	$ 4,434	$ 3,647	$ 13,133	$ 5,105	$ 15,577
Adjusted cash-based general and administrative expenses per BOE	$ 2.22	$ 5.13	$ 4.26	$ 3.48	$ 4.91	$ 4.66

Non-GAAP Reconciliation - PV-10 - Unaudited

Reconciliation of GAAP "Standardized Measure of Discounted Future Net Cash Flows" to Non-GAAP "PV-10"

Non-GAAP PV-10 value is the estimated future net cash flows from estimated proved reserves discounted at an annual rate of 10 percent before giving effect to income taxes. The standardized measure of discounted future net cash flows is the after-tax estimated future cash flows from estimated proved reserves discounted at an annual rate of 10 percent, determined in accordance with generally accepted accounting principles (GAAP). We use non-GAAP PV-10 value as one measure of the value of our estimated proved reserves and to compare relative values of proved reserves among exploration and production companies without regard to income taxes. We believe that securities analysts and rating agencies use PV-10 value in similar ways. Our management believes PV-10 value is a useful measure for comparison of proved reserve values among companies because, unlike standardized measure, it excludes future income taxes that often depend principally on the characteristics of the owner of the reserves rather than on the nature, location and quality of the reserves themselves.

	December 31,	
(in thousands)	2017	2016 [1]
Standardized measure of future discounted cash flows	$590,484	$317,550
Present value of future income taxes discounted at 10%	18,486	-
PV-10	$608,970	$317,550

[1] Due primarily to our net operating loss carry forwards, our standardized measure of future discounted cash flows does not include any income tax effect.

Strip Pricing as of December 31, 2017

NYMEX Pricing Used inthe Calculation of PV-10 at Strip

	Calendar Year Average	
	Oil (per barrel)	**Natural Gas (per MMBtu)**
2018	$59.55	$2.87
2019	$56.22	$2.81
2020	$53.79	$2.82
2021	$52.29	$2.85
2022	$51.70	$2.89
2023	$51.59	$2.93
2024	$51.76	$2.97
2025	$52.07	$3.01
2026	$52.47	$3.07

The Company used the average pricing for the year shown above and flat pricing after 2026.

Definitions and Calculations

Drill-Bit Finding and Development Cost - Definition

Drill-bit finding and development costs for full year 2017 of approximately $4.40 per BOE was calculated by dividing the sum of development costs of $133.0 million by total reserve, extensions and discoveries of 30.2 MMBOE. Drill-bit finding and development cost is a supplemental used to assist in an evaluation of how much it costs the Company, on a per BOE basis, to add proved reserves. This calculation does not include the future development costs required for the development of proved undeveloped reserves.

Reserve Replacement Ratio - Definition

The Company uses the reserves replacement ratio as an indicator of the Company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. The reserves replacement ratio is a statistical indicator that is limited because it typically varies widely based on the extent and timing of discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not embed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. The reserve replacement ratio of approximately 710% was calculated by dividing net proved reserve additions of 26.9 MMBOE (the sum of extensions, discoveries, revisions and purchases) by production of 3.8 MMBOE.