APRIL 2017

2017 IPAA OGIS NEW YORK

Certain Disclosures

This presentation contains forward-looking statements. These forward-looking statements can be identified by use of forward-looking terminology including “may,” “assume,” “estimate,” “project,” “believe,” “plan,” “expect,” “anticipate,” “intend,” “forecast,” “continue” or other similar words. These statements discuss future operating or financial performance or events. Descriptions of Legacy’s objectives, goals, targets, plans, strategies, budgets and projected financial and operating performance are also forward-looking statements. These statements represent our present expectation or beliefs concerning future events and are not guarantees. Such statements speak only as of the date they are made, and Legacy does not undertake any obligation to update any forward-looking statement. We caution that forward-looking statements involve risks and uncertainties and are qualified by important factors that could cause actual events or results to differ materially from those expressed or implied in any such forward-looking statements.

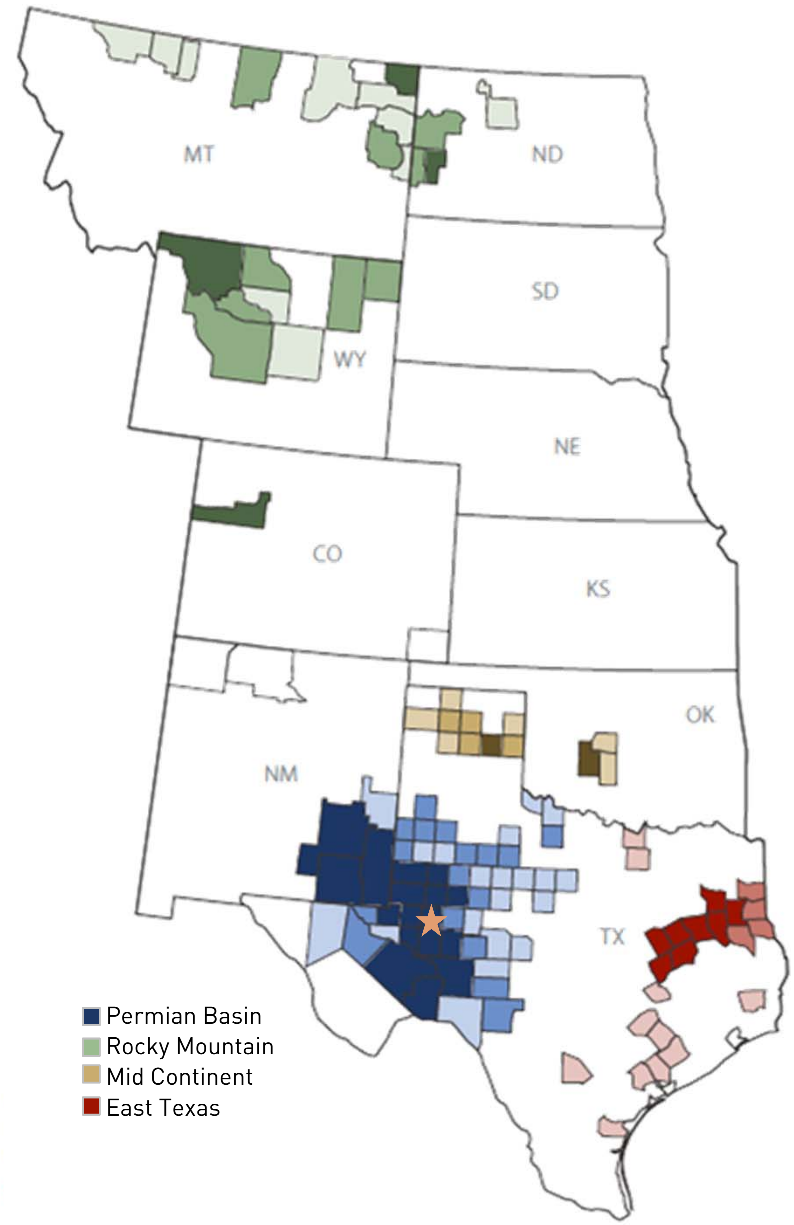
Investors are also urged to consider closely the disclosure relating “Risk Factors” and “Forward-Looking Statements” in Legacy Reserves LP’s Annual Report on Form 10-K for the year ended December 31, 2016 (the “Annual Report”), and subsequent filings with the Securities Exchange Commission (the “SEC”). The Annual Report is available from Legacy’s website at www.legacylp.com. You can also obtain this form from the SEC by visiting EDGAR.

Legacy continues to evaluate opportunities to improve its balance sheet. Potential future repurchases or cancellations of outstanding senior notes and/or asset sales by the Company could result in a tax liability for Legacy's unitholders. The effect to each unitholder would depend on the unitholder's individual tax position with respect to the units. If available, prior year passive losses from a unitholder's interest in the Company may serve to reduce or eliminate a unitholder's current and future year taxable income and related income tax liability.

Although Legacy has suspended distributions to both the 8% Series A and Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units"), such distributions continue to accrue. Pursuant to the terms of Legacy's partnership agreement, Legacy is required to pay or set aside for payment all accrued but unpaid distributions with respect to the Preferred Units prior to or contemporaneously with making any distribution with respect to Legacy's units. Accruals of distributions on the Preferred Units are treated for tax purposes as guaranteed payments for the use of capital that will generally be taxable to the holders of such Preferred Units as ordinary income even in the absence of contemporaneous distributions.

Legacy Reserves LP Overview

- Longstanding Midland, Texas-based operator (NASDAQ: LGCY)
- Unique balance of diversified, stable PDP footprint with significant horizontal Permian potential
  - 42 MBoe/d from 4 regions with <9% decline
  - Nearly 600 gross / 300+ net operated horizontal Permian drilling locations
- Weathered the 2016 storm with several great accomplishments
- Given resource delineation and recent well results, we are excited about our short and long-term opportunities to grow equity value



Note: Darker shading represents increased reserve concentration

2016 Key Accomplishments

- Production: Generated record production of 43,800 Boe/d.
- LOE: Reduced absolute LOE by $13 million and achieved record low lifting cost of $10.59/Boe
- Drilling Efficiencies: Reduced D&C cost of horizontals by 15% primarily through programmatic reduction in drilling days
- Asset Sales: Sold $97 million of assets in 26 transactions that were generating negative cash flow
- Debt Reduction: Reduced total debt by $269 million and annualized interest expense by $11.7 million; year-end revolver liquidity of $135 million
- JDA Expansion: Obtained increased commitment from TPG Special Situations Partners ("TSSP") to $275 million and 48 horizontal wells
  - Currently operating two horizontal rigs; one in Lea County, NM, and one in Howard County, TX
  - 24 horizontal wells brought online since commencement of the JDA program in July 2015
- 2nd Lien: Partnered with GSO Capital Partners LP ("GSO") in raising a New 2nd Lien Term Loan which reduced bank debt outstanding and provides a new source of future capital for the business. Added 1 GSO board member to be actively involved in Company's growth plans

Valuation and Credit Profile Underpinned by Significant PDP

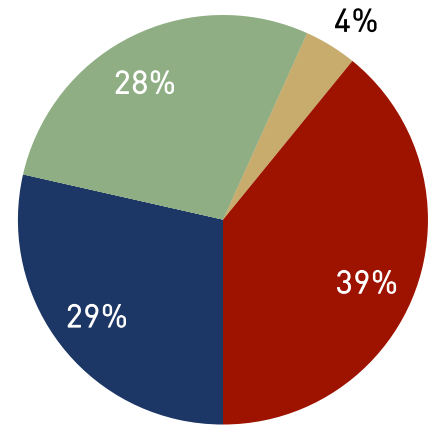
- ~$970 million Proved PV-10 based on Strip Pricing[1]
- Weighted average 3-year PDP decline rate <9%

PDP Decline Rate and Production Allocation by Region

	PDP Decline Rate (%)		% of Production	
Region	1 yr	3 yr	Q4'16	2017E
Permian (excl. JDA)	12%	10%	29%	26%
Permian JDA	30%	29%	2%	8%
East Texas	9%	7%	32%	31%
Mid-Con	5%	5%	4%	3%
Rockies	8%	7%	33%	32%
Total	10%	9%	100%	100%

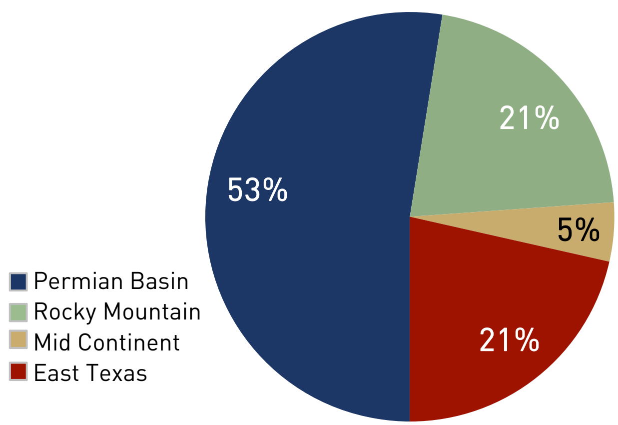
- ~77% of PDP hedged through 2018[3]
  - ~75% PDP Oil hedged @ $57.14[4]
  - ~77% PDP Gas hedged @ $3.30[4]

Proved Reserves by Region



145MMBoe; 94% PDP @ SEC Pricing [2]
165MMBoe; 94% PDP @ Strip Pricing [1]

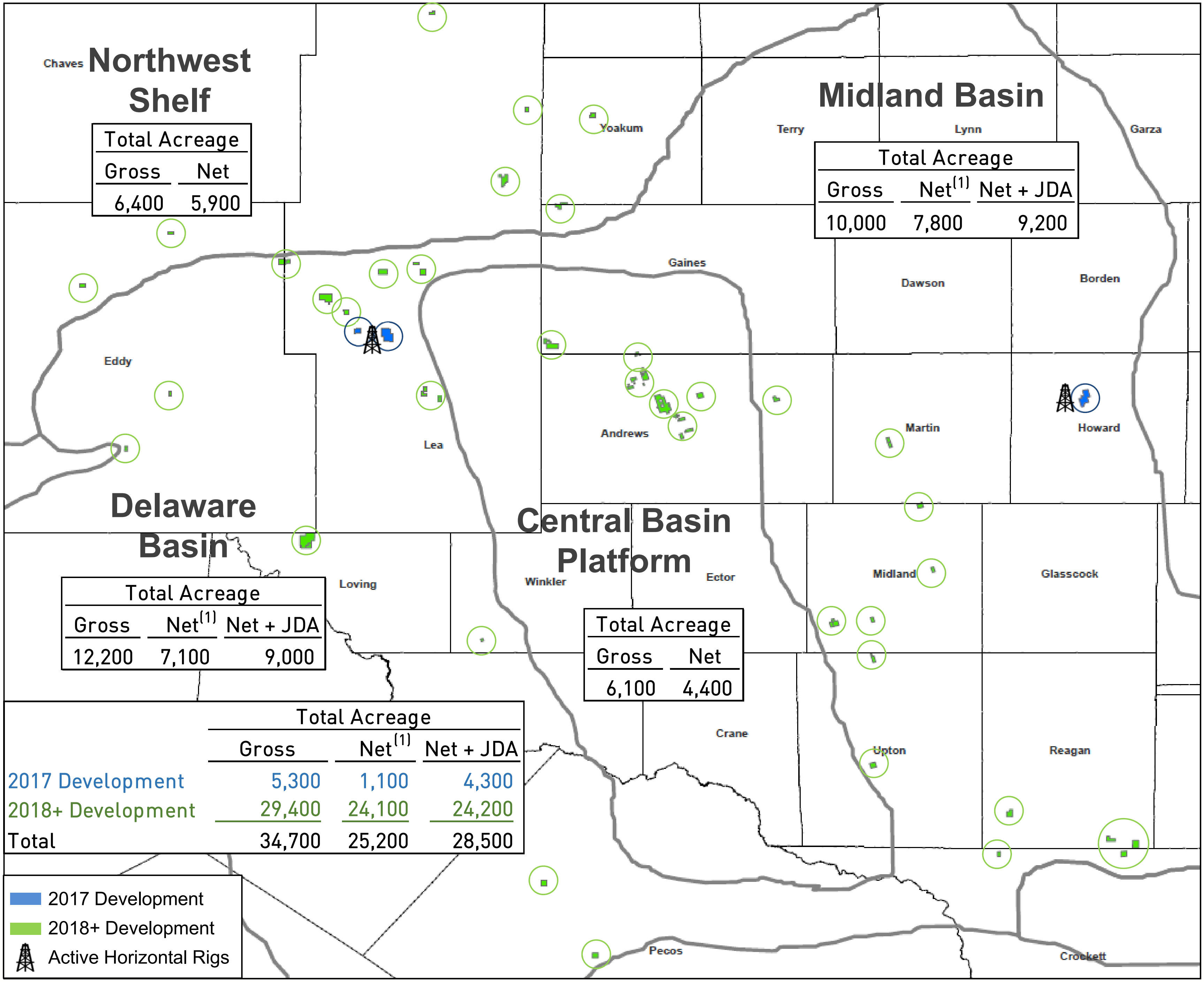
Proved PV-10 by Region



$970 million @ Strip Pricing [1]

(1) Source: Year-end SEC Reserve Report run at 5 year forward average NYMEX strip pricing at February 14, 2017 ($54.86 Oil / $2.97 Gas)
(2) Source: Year-end SEC Reserve Report run at year-end 2016 SEC pricing (Plains posted oil price of $39.25 / Platts Gas Daily price of $2.48)
(3) Excludes NGL's.
(4) Represents the effective oil and gas prices (before the impacts of differentials) after the impact of hedges using NYMEX pricing as of February 14, 2017 (2017 - Oil $54.24 / Gas $3.24. 2018 - Oil $55.28 / Gas $3.05). See slide 19 for hedge summary.

Identified Operated Permian Horizontal Acreage



Northwest Shelf – Total Acreage

Gross	Net
6,400	5,900

Delaware Basin – Total Acreage

Gross	Net[1]	Net + JDA
12,200	7,100	9,000

Central Basin Platform – Total Acreage

Gross	Net
6,100	4,400

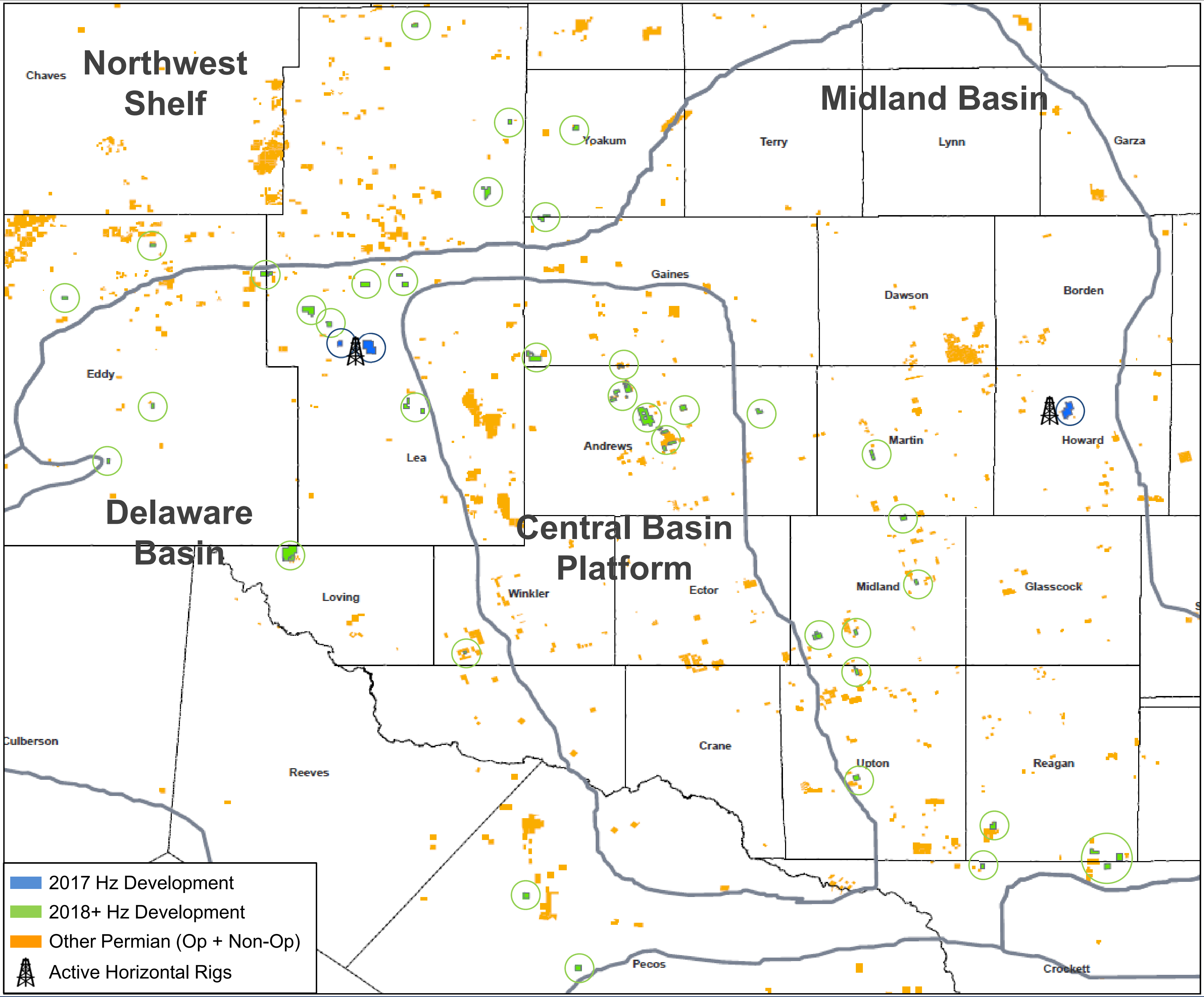
Midland Basin – Total Acreage

Gross	Net[1]	Net + JDA
10,000	7,800	9,200

	Total Acreage		
	Gross	Net[1]	Net + JDA
2017 Development	5,300	1,100	4,300
2018+ Development	29,400	24,100	24,200
Total	34,700	25,200	28,500

Note: References to development year are based on management projections and are subject to change.
(1) Net figures reflect our 20% remaining working interest in acreage conveyed to TSSP under the terms of the JDA.

Total Permian Acreage



Note: References to development year are based on management projections and are subject to change.

Significant Operated Permian Horizontal Development Inventory

- Extensive industry activity has de-risked a significant number of drilling locations across Legacy's position
- Coordinated efforts across land, geology and operations teams have identified these attractive prospects
- Most recent 16 wells averaged IP30 > 1,000 Boe/d with projected IRR of 40-70%[4]

Permian Horizontal Inventory

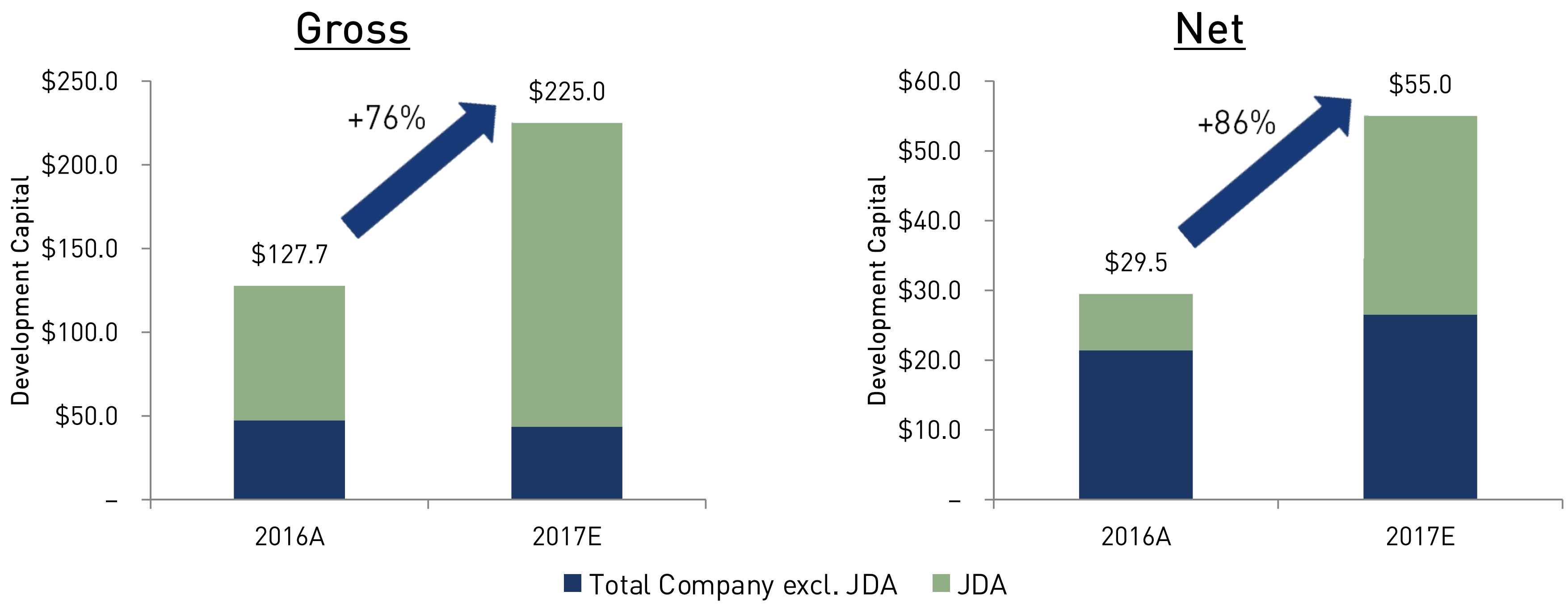
	Operated Horizontal Drilling Locations[1]						Wells per Section[2]
	2017 Development		2018+ Development		Total		
	Gross	Net[3]	Gross	Net [3]	Gross	Net	
Midland Basin							
Lower Sprayberry	8	3.2	48	24	56	27	8
Wolfcamp	10	4.4	235	151	245	156	8
Devonian	–	–	5	3	5	3	5
Delaware Basin							
Brushy Canyon	–	–	28	15	28	15	4
1st Bone Spring	1	0.1	34	13	35	13	4
2nd Bone Spring	7	1.0	35	16	42	17	4
3rd Bone Spring	3	0.4	15	8	18	8	4
Wolfcamp	–	–	30	13	30	13	4
Central Basin Platform							
San Andres	–	–	64	36	64	36	5
Northwest Shelf							
San Andres	–	–	22	17	22	17	4
Yeso	–	–	2	2	2	2	4
Abo / Wolfcamp	–	–	28	19	28	19	4
Devonian	-	-	10	5	10	5	5
Horizontal Total	29	9.1	556	320	585	329	

Note: References to development year are based on management projections and are subject to change.
(1) Assumes mostly 7,500' laterals (with some 10,000' laterals) in the Midland Basin and 5,000' lateral lengths in all other areas. Where incomplete lateral ownership exists, net location count assumes proportional dilution of interest.
(2) Spacing based on analogous, nearby development.
(3) Net figures reflect our 20% remaining working interest in acreage conveyed to TSSP under the terms of the JDA. Any other locations that may fall under the JDA AMI have not been proportionately reduced.
(4) Economics net to LGCY and TSSP's combined interest in the JDA based on a 75% NRI and run at 5 year forward average NYMEX strip pricing at February 14, 2017 ($54.86 Oil / $2.97 Gas)

2017 Capital Budget

($ in millions)

$55 million Capital Budget



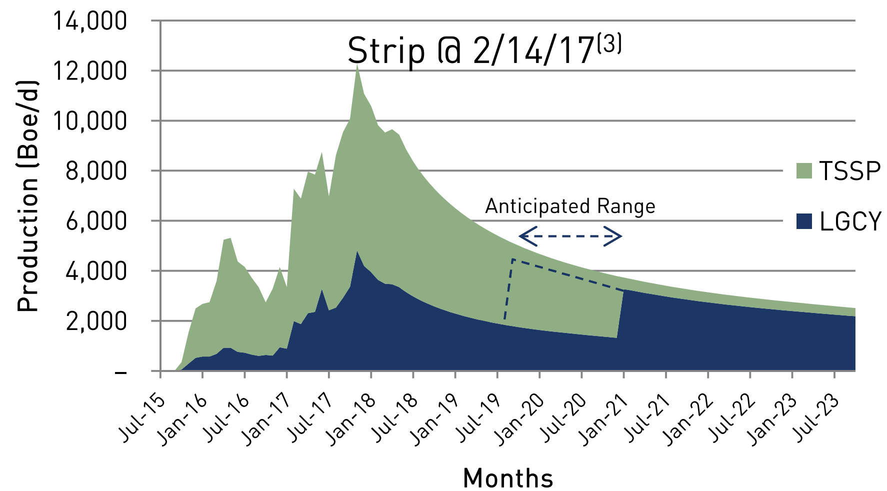
- 2017 capital increases over 2016 primarily due to (i) a lack of 6 month drilling pause in our 2016 horizontal development and (ii) increased working interest in our Howard County, TX development
- Robust capital program including JDA economics is anticipated to grow company oil production by 20+% (Q4'17 vs. Q4'16) with minimal capital spend while generating significant free cash flow
- Currently undertaking analysis of horizontal potential across portions of our 89,000 net acres in East Texas and may drill unbudgeted test well(s) in 2017

JDA Overview

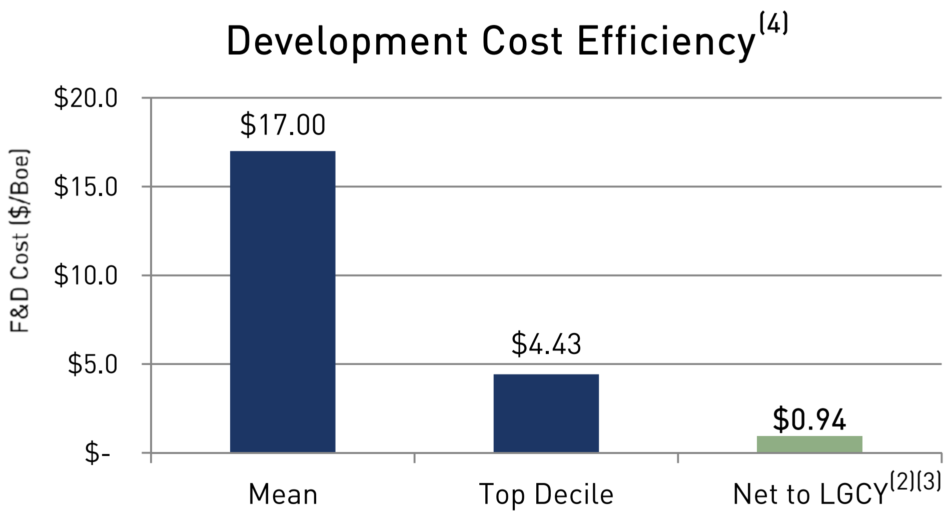
JDA Summary Economic Terms

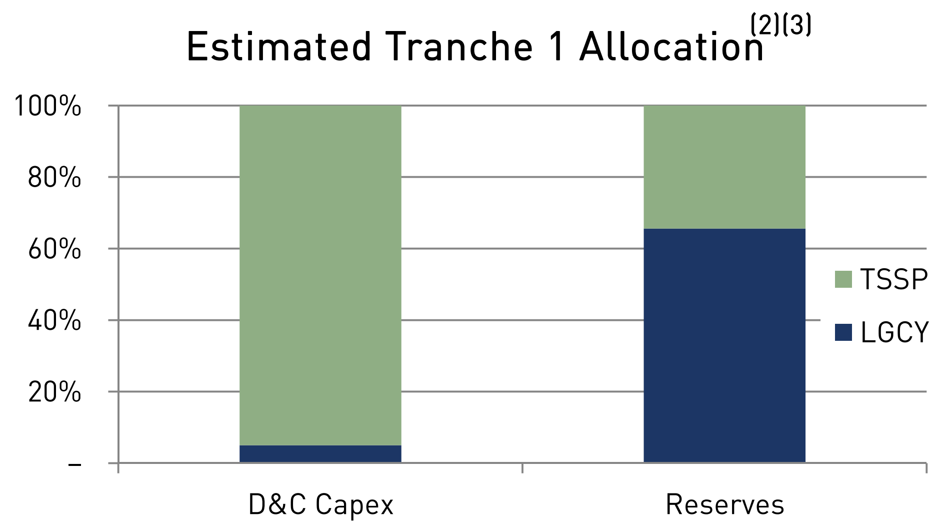
	LGCY	TSSP
Capital Contribution	5%	95%
Capital Contribution ($mm)	$14.5	$275.0
Initial WI	20%	80%
WI upon TSSP Receiving 15% IRR	85%	15%

Tranche(1) 1 Reversion Profile (48 Wells)(2)



Efficiencies and Results



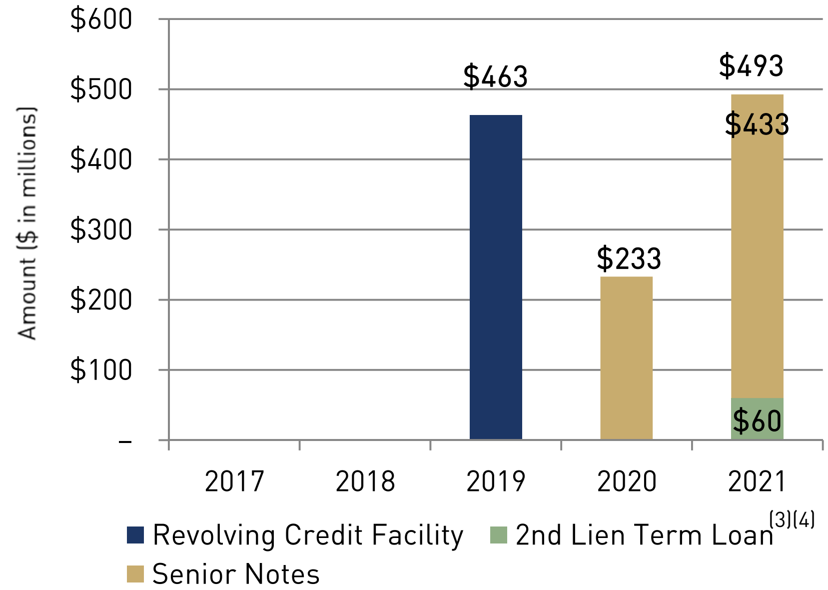


(1) Reversion math based on TSSP's investment return on a group (or "tranche") of wells and not on a single well basis
(2) Includes LGCY ORRI's which average 6% for the 48 expected wells in the tranche.
(3) Source: LGCY estimates run at 5 year forward average NYMEX strip pricing at February 14, 2017 ($54.86 Oil / $2.97 Gas)
(4) Based on F&D Cost ($/Boe – excluding revisions) per SEC filings for the year-ended 12/31/2015 for the following E&P Companies: APA, AR, AREX, BBG, BCEI, CHK, CLR, COG, COP, CRK, CRZO, CWEI, CXO, DVN, ECA, ECR, EGN, EOG, EPE, EQT, FANG, GPOR, GST, HK, JONE, LPI, MPO, MRO, MTDR, MUR, NBL, NFX, NOG, OAS, PDCE, PE, PQ, PXD, QEP, REN, REXX, RICE, RRC, RSPP, SD, SGY, SM, SN, SWN, TPLM, WLL, WPX, WTI, XCO, XEC

Balance Sheet

($ in millions)	12/31/2015	12/31/2016
Revolving credit facility due 2019	$608.0	$463.0
12% 2nd Lien Term Loan due 2021	–	$60.0
8% Senior Notes due 2020	$300.0	$233.0
6.625% Senior Notes due 2021	$550.0	$432.7
Total Debt	$1,458.0	$1,188.6
Borrowing Base	$725.0	$600.0
Liquidity[1]	$115.6	$135.1
Annualized Cash Interest Expense[2]	$84.8	$73.0
Change since 12/31/15:		
Revolving credit facility due 2019		($145.0)
12% 2nd Lien Term Loan due 2021		$60.0
8% Senior Notes due 2020		($67.0)
6.625% Senior Notes due 2021		($117.3)
Total Debt		($269.4)
Liquidity[1]		$19.5
Annualized Cash Interest Expense[2]		($11.7)

No Near-Term Debt Maturities



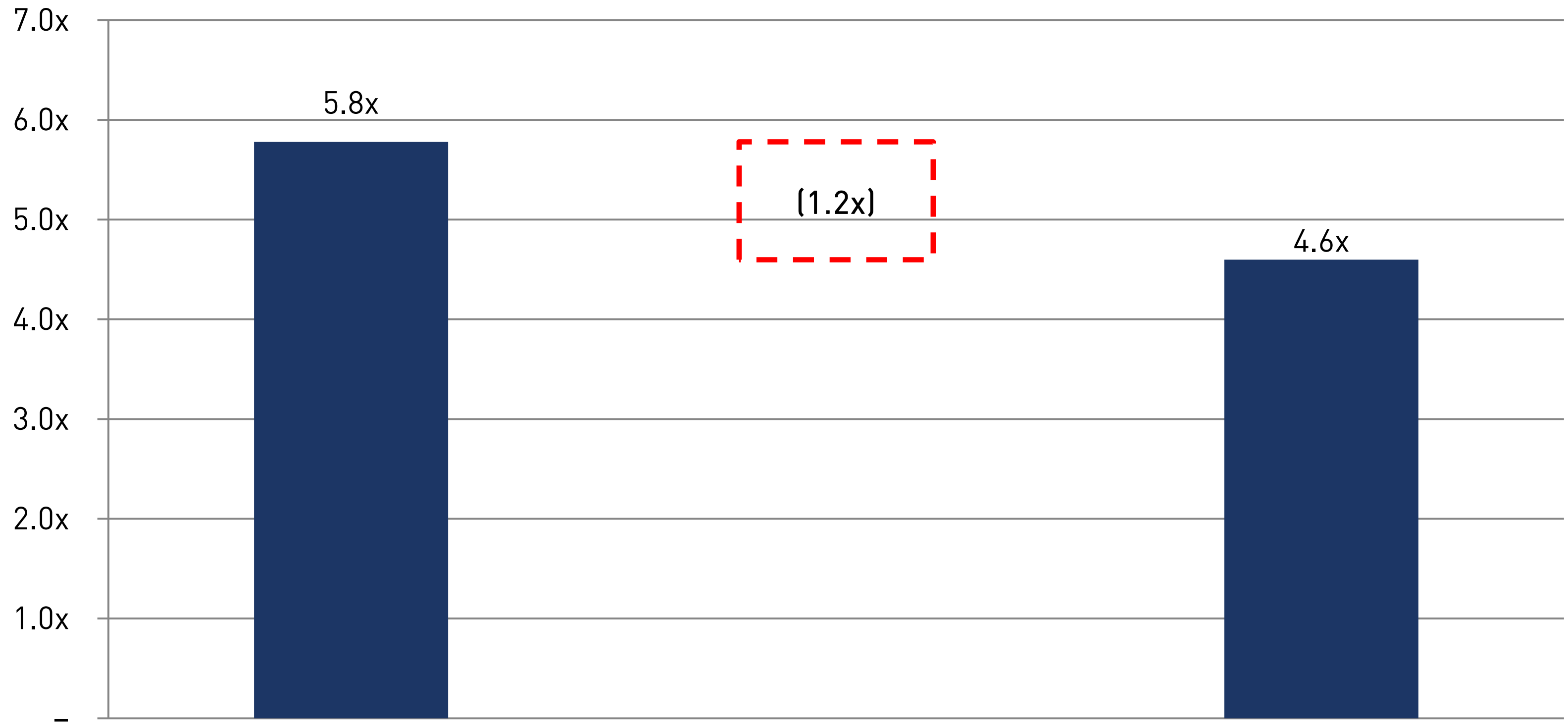
- Borrowing Base reaffirmed at $600 million in March 2017
- Operative financial covenants, for which we do not forecast any issues, include: 3.25x → 2.50x Revolver / EBITDA, 2.0x EBITDA / Interest, and beginning 6/30/17, Secured Debt Asset Coverage of 1.0x
- Preferred and common unit distributions are prohibited unless the Total Debt / EBITDA ratio is less than 4.0x[5]
- We anticipate the continued suspension (Preferred + common) and will focus on growing unitholder value by growing asset value

(1) Reduced by $1.4 and $1.9 million in outstanding letters of credit at YE'15 and YE'16, respectively.
(2) Assumes 4% interest rate for the revolving credit facility.
(3) $300 million facility allows $240 million of incremental funds available through October 25, 2017.
(4) Excludes the springing maturity date of August 1, 2020, if greater than or equal to $15 million of Senior Notes is outstanding on July 1, 2020.
(5) Preferred distributions continue to accrue and are treated for tax purposes as guaranteed payments that will generally be taxable to the holders as ordinary income even in the absence of contemporaneous distributions.

Improved Pro Forma Credit Profile

- The following pro forma assumes we caused a Reversion to occur under the JDA increasing LGCY's WI in the assets:

	LGCY Standalone	+	JDA Adjustment	=	Pro Forma
Numerator	$1,189 [1]		$73 [3]		$1,262
Denominator	$205 [2]		$69		$274



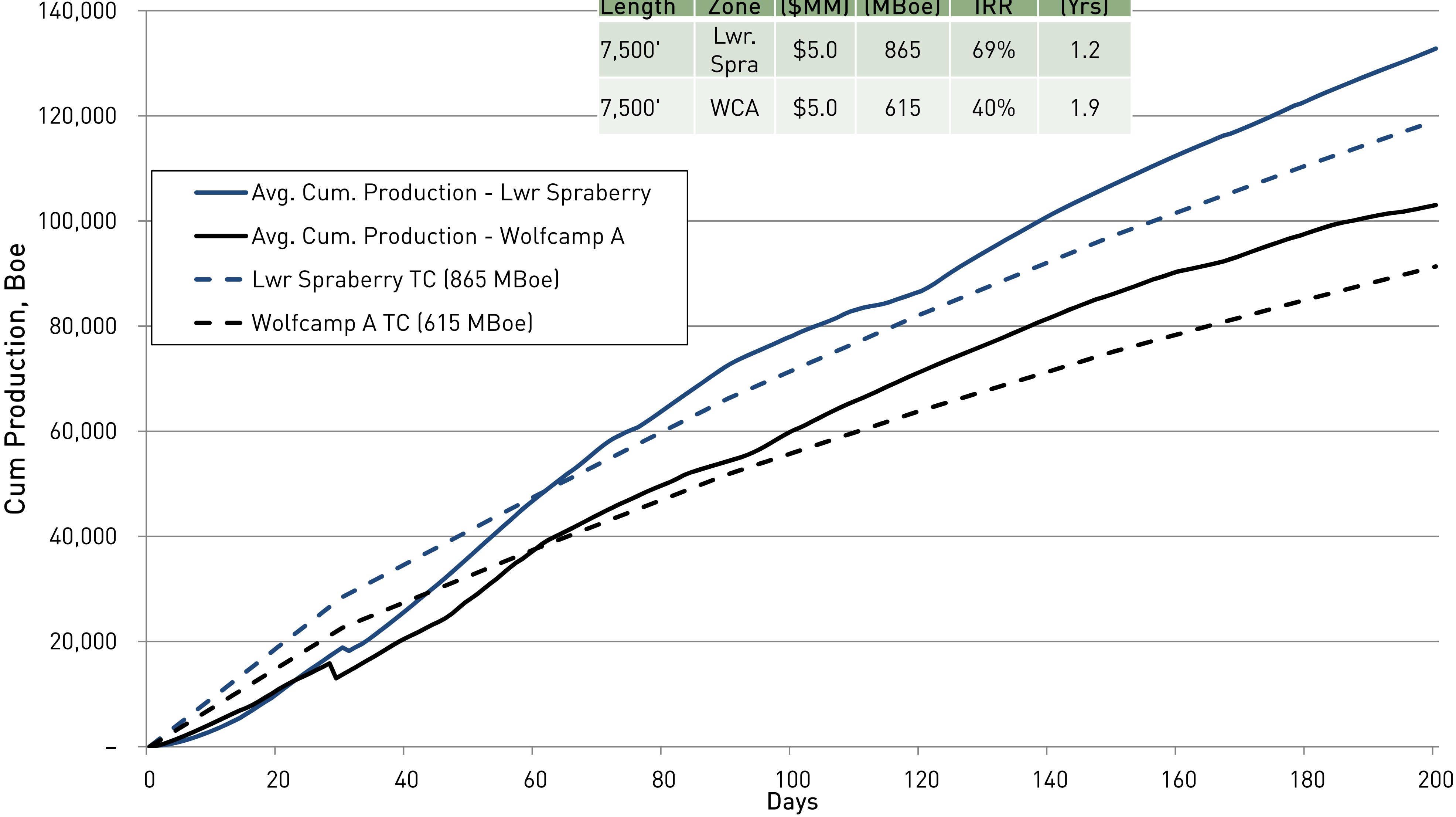
Note: LGCY does not have the contractual right to cause the Reversion today. Such right exists 18 months after the completion of a tranche.
(1) Total Debt as of 12/31/16 excluding any impact of unamortized discount and issuance costs.
(2) Midpoint of 2017E Adjusted EBITDA guidance. Adjusted EBITDA is a non-GAAP measure. A non-GAAP reconciliation is available on our website.
(3) Represents the approximate amount of cash required to achieve Reversion (TSSP's 15% IRR) as of 12/31/2016.

Appendix

Howard County Well Performance

Type Well Statistics[1]

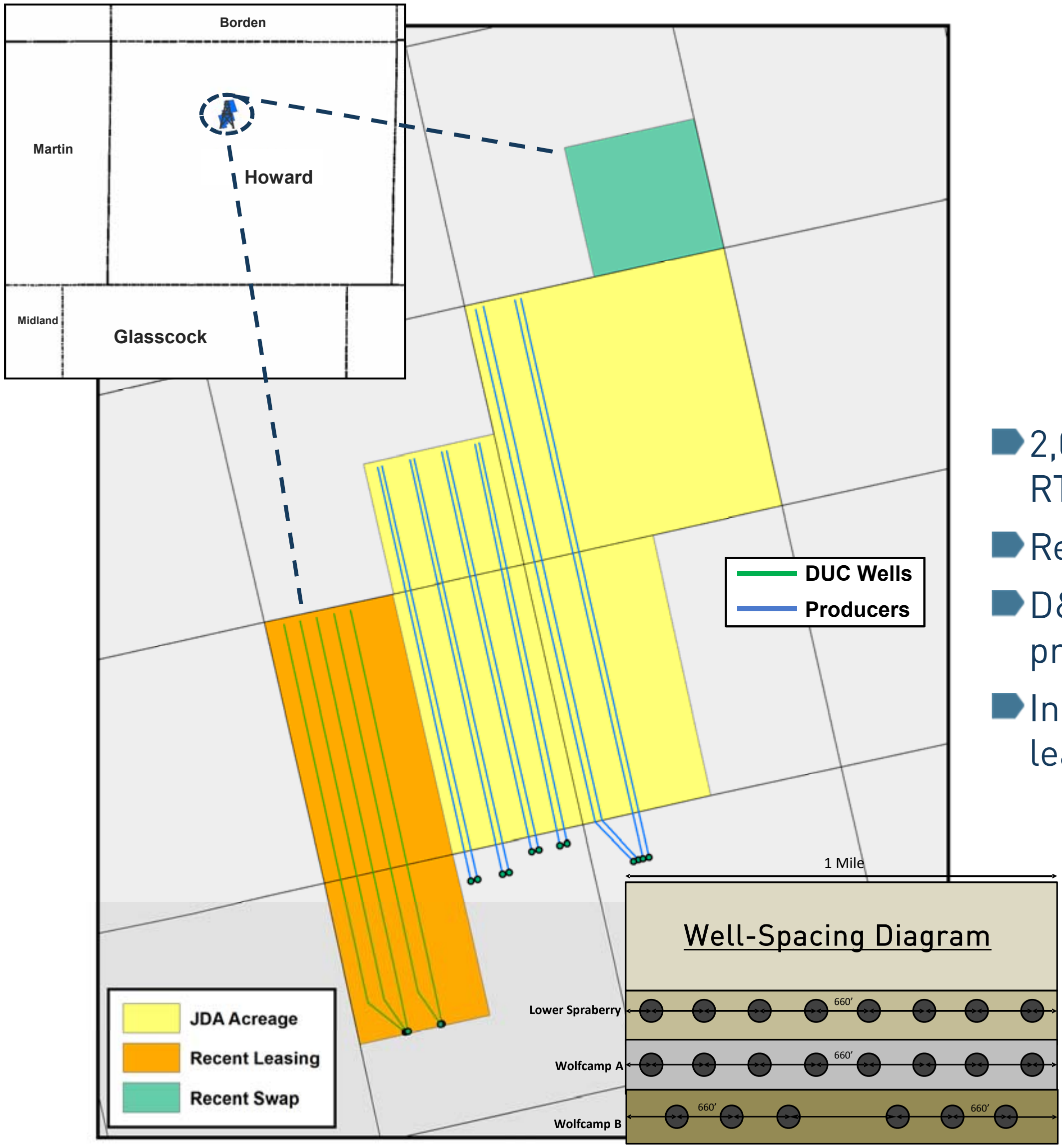
Lateral Length	Zone	D&C ($MM)	EUR (MBoe)	IRR	Payout (Yrs)
7,500'	Lwr. Spra	$5.0	865	69%	1.2
7,500'	WCA	$5.0	615	40%	1.9



(1) Economics net to LGCY and TSSP's combined interest in the JDA based on a 75% NRI and run at 5 year forward average NYMEX strip pricing at February 14, 2017 ($54.86 Oil / $2.97 Gas)

Howard County Activity Update

Map



Results[1]

Well Name	Zone	First Prod.	Lat. Length (ft)	Peak 30-Day (Boe/d)
Talbot A 1SH	L Sprby	Dec-15	7,500	1,144
Talbot B 2AH	WC A	Dec-15	7,500	814
Talbot C 3SH	L Sprby	Mar-16	7,500	1,000
Talbot D 4AH	WC A	Apr-16	7,500	672
Talbot E 5SH	L Sprby	Mar-16	7,500	1,132
Talbot F 6AH	WC A	Mar-16	7,500	1,208
Talbot G 7SH	L Sprby	Nov-16	7,500	1,076
Talbot H 8AH	WC A	Nov-16	7,500	1,092

- 2,053 net acres to TSSP's and LGCY's combined interest in the RTF Block
- Resumed drilling operations in June '16 after 6mo pause
- D&C'd 12 wells in the RTF area to date; awaiting adequate production data to report production for 4 10,000' lateral wells
- Increased #, length and interest in drilling locations through leasing, acreage swaps and acquisitions:

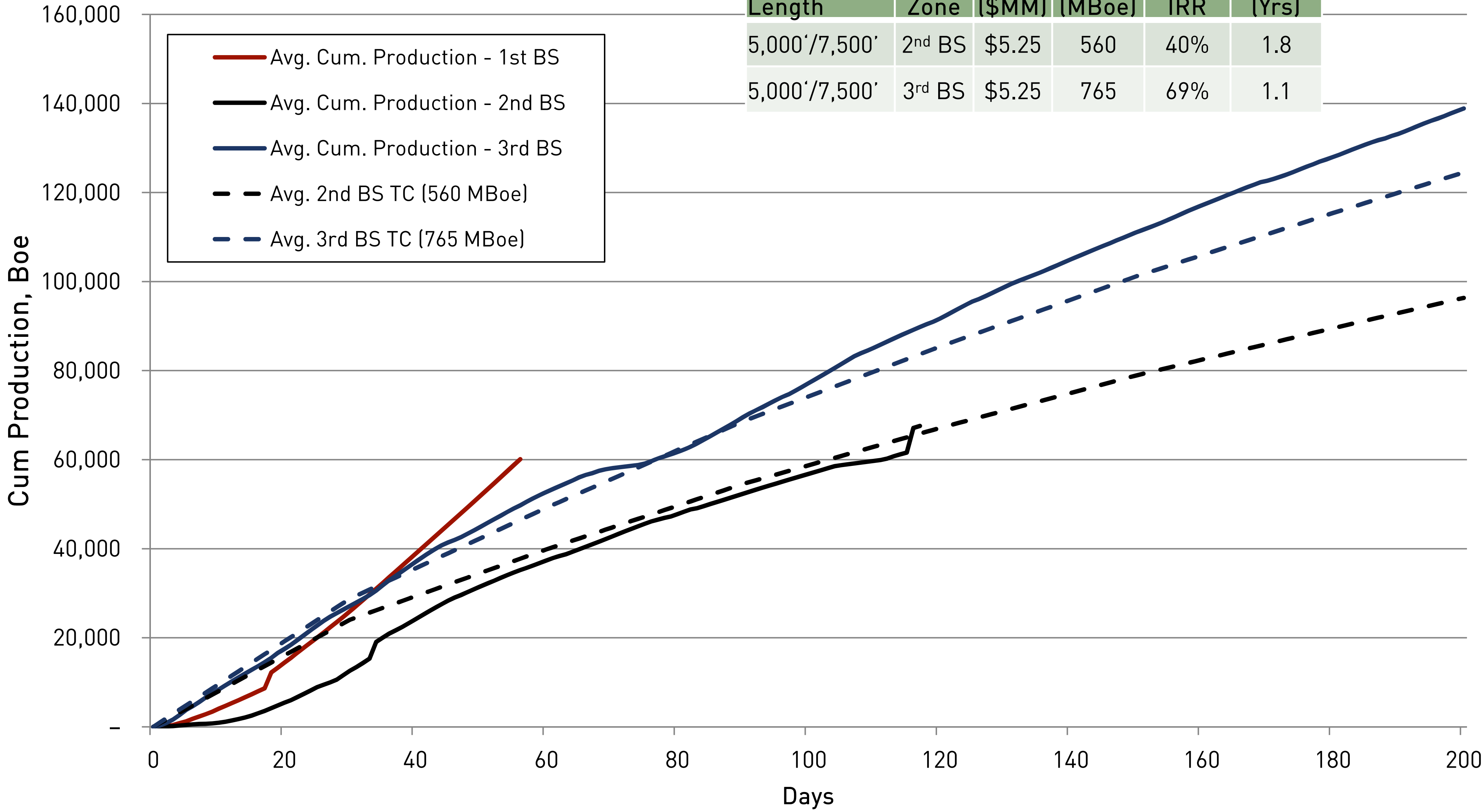
Lateral Length	Prior Locations	Adj.	Total Locations[2]
5,000'	11	(11)	–
7,500'	11	22	33
10,000'	11	–	11
Total	33	11	44

(1) Excludes recent 10,000' well results.
(2) Includes producing and undeveloped locations in the Lower Spraberry, Wolfcamp A and Wolfcamp B zones.

Lea Unit Well Performance

Type Well Statistics[1]

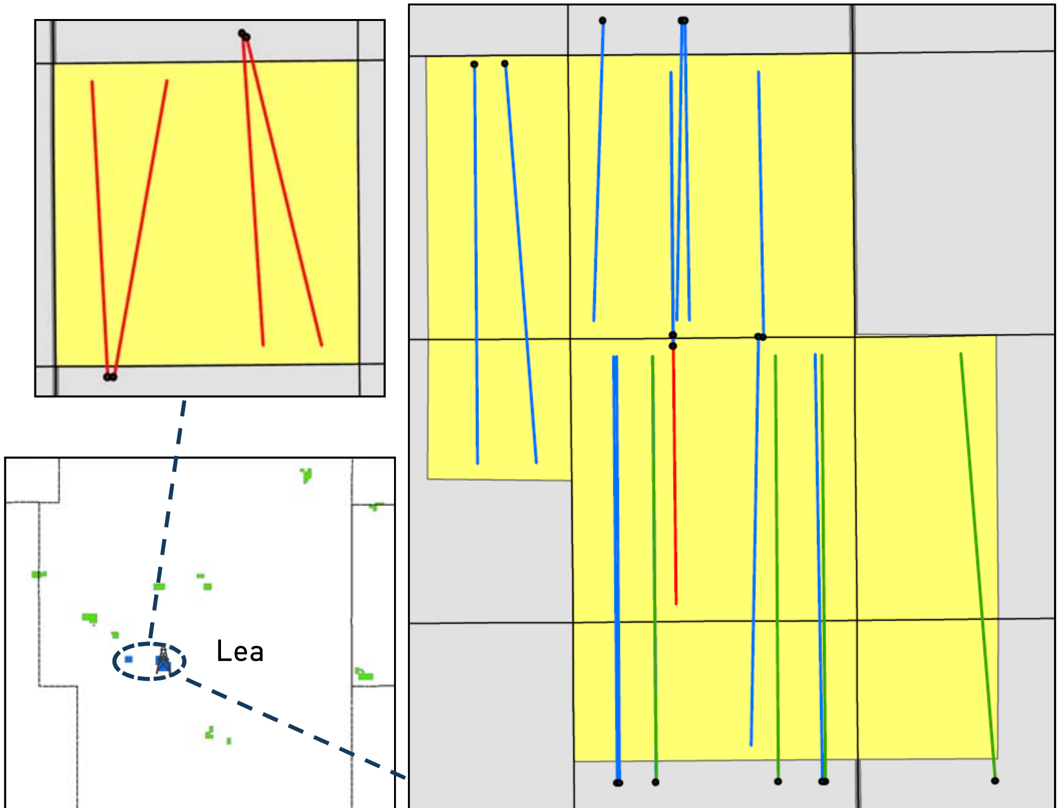
Lateral Length	Zone	D&C ($MM)	EUR (MBoe)	IRR	Payout (Yrs)
5,000'/7,500'	2nd BS	$5.25	560	40%	1.8
5,000'/7,500'	3rd BS	$5.25	765	69%	1.1

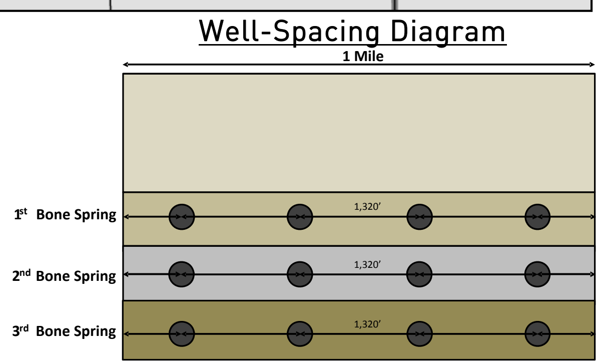


(1) Economics net to LGCY and TSSP's combined interest in the JDA based on a 75% NRI and run at 5 year forward average NYMEX strip pricing at February 14, 2017 ($54.86 Oil / $2.97 Gas)

Lea-Hamon Activity Update

Map





Results

Well Name	Zone	First Prod.	Lat. Length (ft)	Peak 30-Day (Boe/d)
Lea 32H	3rd BS	Nov-15	7,500	1,091
Lea 33H	3rd BS	Oct-15	5,000	876
Lea 34H	3rd BS	Nov-15	5,000	1,523
Lea 44H	3rd BS	Nov-15	5,000	847
Lea 54H	3rd BS	Jan-16	7,500	1,143
Lea 57H	2nd BS	Sep-16	7,500	798
Lea 35H	2nd BS	Oct-16	7,500	954
Lea 39H	1st BS	Dec-16	7,500	1,358
Lea 47H	2nd BS	Jan-17	5,000	N/A
Lea 48H	1st BS	Jan-17	5,000	N/A
Lea 38H	3rd BS	Feb-17	7,500	N/A

- 2,285 net acres to TSSP and LGCY's combined interest in Lea-Hamon
- D&C'ed 11 wells to date in the JDA program:

Zone	PDP	Undeveloped	Total Locations[1]
1st Bone	2	16	18
2nd Bone	3	17	20
3rd Bone	6	5	11
Total	11	38	49

- Assessing Wolfcamp potential

(1) Includes PDP and PUD locations in the 1st, 2nd and 3rd Bone Spring zones developed or to be developed under the JDA program with TSSP.

2017 Guidance

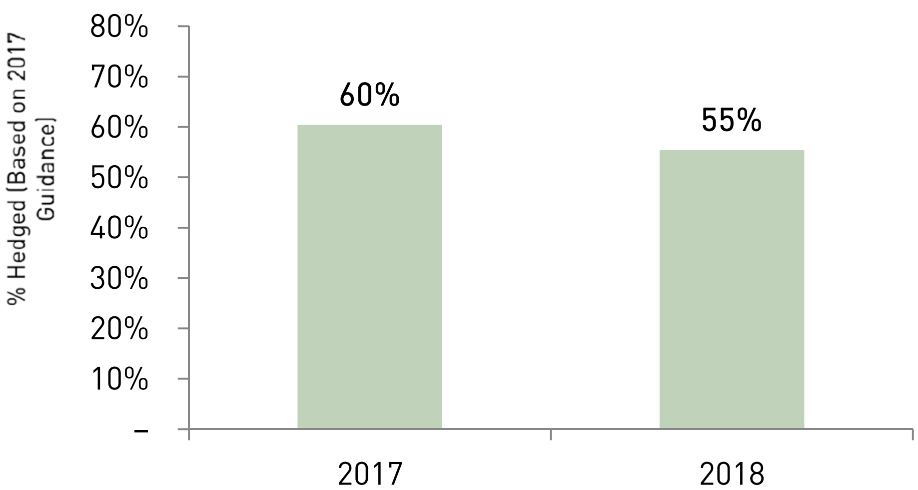
($ in thousands unless otherwise noted)	FY 2017E Range		
Production:			
Oil (MBbls)	4,300	-	4,400
Natural gas liquids (MGal)	35,800	-	36,800
Natural gas (MMcf)	61,300	-	62,900
Total (MBoe)	15,369	-	15,760
Average daily production (Boe/d)	42,107	-	43,178
Weighted Average NYMEX Differentials:			
Oil (per Bbl)	($4.75)	-	($4.00)
NGL realization (1)	1.05%	-	1.23%
Natural gas (per Mcf)	($0.31)	-	($0.26)
Expenses:			
Oil and natural gas production expenses ($/Boe)	$10.80	-	$11.20
Ad valorem and production taxes (% of revenue)	7.50%	-	8.00%
Cash G&A expenses (2)	$33,000	-	$34,000
Capital Expenditures	$55,000	-	$60,000
Adjusted EBITDA(3)	$195,000	-	$215,000

(1) Represents the projected percentage of WTI crude oil price per gallon of NGLs.
(2) Consistent with our definition of Adjusted EBITDA, these figures exclude LTIP expenses. Cash settlements of LTIP (not included herein) impact Distributable Cash Flow.
(3) Adjusted EBITDA is a Non-GAAP financial measure. A reconciliation of this measure to the nearest comparable GAAP measure is available on our website.
Note: Figures above assume NYMEX strip pricing at 2/14/2017 (2017 Avg Oil $55.24 / $3.24 Gas).

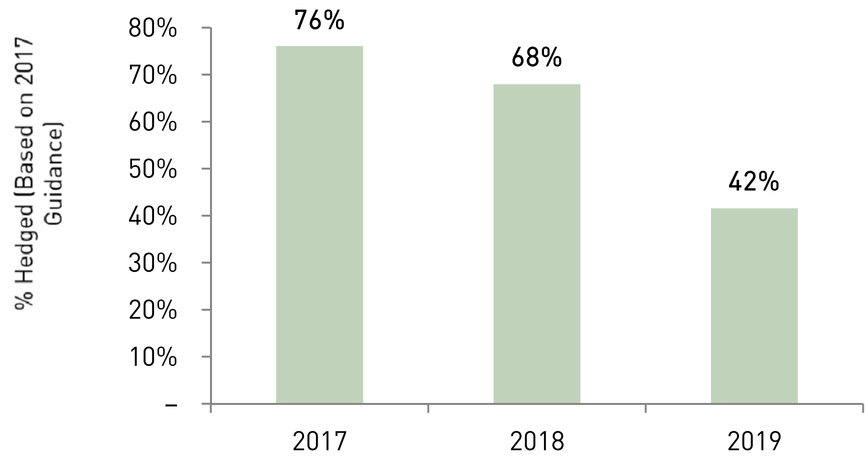
Hedge Summary + Price Sensitivities

- Added meaningful hedges over the past 6 months. Below is our current position:

% Oil Hedged[1]



% Natural Gas Hedged[1]



- Set forth below are the effective oil and gas prices (before the impacts of differentials) and after the impact of hedges:

		Effective Oil Price (Before Differentials)	
		2017	2018[1]
Avg WTI Oil Price	$40	$45.90	$45.79
	$50	$52.54	$51.30
	$60	$61.33	$59.27
	$70	$65.71	$64.28

		Effective Gas Price (Before Differentials)	
		2017	2018[1]
Avg Henry Hub Gas Price	$2.75	$3.10	$3.09
	$3.00	$3.20	$3.17
	$3.25	$3.34	$3.25
	$3.50	$3.46	$3.33

(1) 2018 and 2019 projected production has not been provided and for this analysis is based on the mid-point of 2017 guidance.