REX ENERGY®

CORPORATE PRESENTATION

November 2017

Cautionary Statements

Forward Looking Statements

Statements in this presentation that are not 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 believe these statements and the assumptions and estimates contained in this presentation are reasonable based on information that is currently available to us. However, management's assumptions and the company's future performance are subject to a wide range of business risks and uncertainties, both known and unknown, and we cannot assure that the company can or will meet the goals, expectations and projections included in this presentation. Any number of factors could cause our actual results to be materially different from those expressed or implied in our forward looking statements, including (without limitation): economic conditions in the United States and globally; domestic and global demand for oil and natural gas; volatility in oil, gas and natural gas liquids pricing; new or changing government regulations; uncertainties inherent in the estimates of our oil and natural gas reserves; our ability to increase natural gas production and income through exploration and development; drilling and operating risks; the success of our drilling techniques in unconventional reservoirs; the number of potential well locations to be drilled, the cost to drill them, and the time frame within which they will be drilled; the ability of contractors to timely and adequately perform their drilling, construction, well stimulation, completion and production services; the availability of equipment, such as drilling rigs, and infrastructure, such as transportation pipelines; the effects of adverse weather or other natural disasters on our operations; competition in the oil and gas industry in general, and specifically in our areas of operation; changes in the company's drilling plans and related budgets; the success of prospect development and property acquisition; the success of our business and financial strategies, and hedging strategies; conditions in the domestic and global capital and credit markets and their effects on us; the adequacy and availability of capital resources, credit and liquidity including (without limitation) access to additional borrowing capacity; and uncertainties related to the legal and regulatory environment for our industry, and our own legal proceeding and their outcome. Further information on the risk and uncertainties that may effect our business is available in the company's filings with the SEC, and we strongly encourage readers to review and understand those risks. Rex Energy does not assume or undertake any obligation to publicly update or revise and forward-looking statements, whether as a result of new information, future events, or otherwise.

Presentation of Information

The estimates of reserves in this presentation are based on a reserve report of our independent external reserve engineers as of December 31, 2016. We believe the data we prepared and supplied to our external reservoir engineers in connection with their preparation of the 12/31/2016 reserve report, and the assumptions, forecasts, and estimates contained therein, are reasonable, however we cannot assure that they will prove to have been correct. Estimates of reserves can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. In this presentation, references to Rex Energy, Rex, REXX, the Company, we, our and us refer to Rex Energy Corporation and its subsidiaries. Unless otherwise noted, all references to acreage holdings are as of December 31, 2015 and are rounded to the nearest hundred. All financial information excludes discontinued operations unless otherwise noted. All estimates of internal rate of return (IRR) are before tax.

Hydrocarbon Volumes

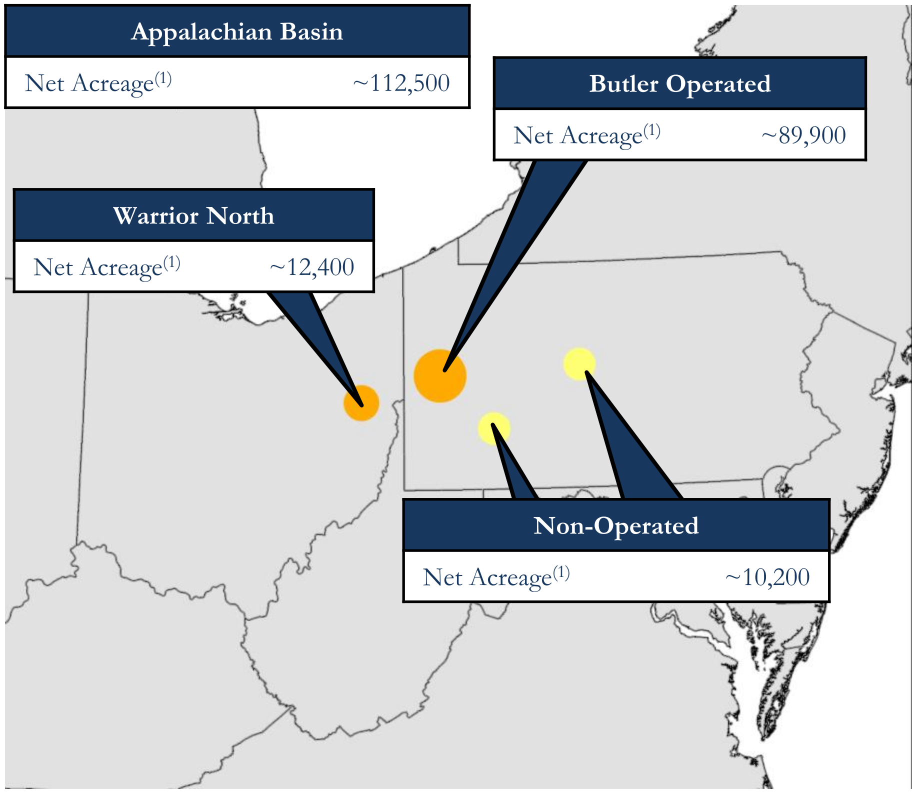
The SEC permits publicly-reporting oil and gas companies to disclose "proved reserves" in their filings with the SEC. "Proved reserves" are estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from know reservoirs under existing economic and operating conditions. SEC rules also permit the disclosure of "probable" and "possible" reserves. Rex Energy discloses proved reserves but does not disclose probable or possible reserves. We may use certain broader terms such as "resource potential," "EUR" (estimated ultimate recovery of resources, defined below) and other descriptions of volumes of potentially recoverable hydrocarbons throughout this presentation. These broader classifications do not constitute "reserves" as defined by the SEC and we do not attempt to distinguish these classifications from probable or possible reserves as defined by SEC guidelines. In addition, we are prohibited from disclosing hydrocarbon quantities that do not constitute reserves in documents field with the SEC. The company defined EUR as the cumulative oil and gas production expected to be economically recovered from a reservoir or individual well from initial production until the end of its useful life. Our estimates of EURs and resource potential have been prepared internally by our engineers and management without review by independent engineers. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. We include these estimates to demonstrate what we believe to be the potential for future drilling and production by the company. Ultimate recoveries will be dependent upon numerous factors including actual encountered geological conditions, the impact of future oil and gas pricing, exploration and development costs, and our future drilling decisions and budgets based upon our future evaluation risk, returns and the availability of capital and, in many areas, the outcome of negotiation of drilling arrangements with holders of adjacent or fractional interest leases. Estimates of resource potential and other figures may change significantly as development of our resources plays provide additional data and therefore quantities that may ultimately be recovered will likely differ materially from these estimates.

Potential Drilling Locations

Our estimates of potential drilling locations are prepared internally by our engineers and management and are based upon a number of assumptions inherent in the estimates process. Management, with the assistance of engineers and other professionals, as necessary, conducts a topographical analysts of our unproved prospective acreage to identify potential well pad locations using operationally approved designs and considering several factors, which may include but are not limited to access roads, terrain, well azimuths, and well pad sizes. For our operations in Pennsylvania, we then calculate the number of horizontal well bores for which the company appears to control sufficient acreage to drill the lateral wells form each potential well pad location to arrive at an estimate number of net potential drilling locations. For our operations in Ohio, we calculate the number of horizontal wells bores that may be drilled from the potential well pad and multiply this by the company's net working interest percentage of the proposed unit and arrive at an estimate number of net potential drilling locations. In both cases, we then divide the unproved prospective acreage by the number of net potential drilling locations to arrive at an average well spacing. Management uses these estimates to, among other things, evaluate our acreage holdings and to formulate plans for drilling. Any number of factors could cause the number of wells we actually drill to vary significantly form these estimates, including: the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, lease expirations, regulatory approvals and other factors.

Company Overview

Rex Energy is a pure-play Appalachian Basin focused company targeting wet-gas windows in the Pennsylvania Marcellus and Ohio Utica Shales



Key Statistics	
Market Capitalization[3]	$21.7 million
Production	
2016A[4]	195.3 Mmcfe/d
1Q17A[5]	173.4 Mmcfe/d
2Q17A	177.1 Mmcfe/d
3Q17A	182.0 Mmcfe/d
4Q17E	
2017E	180.0 – 190.0 Mmcfe/d
2018E	255.0 – 265.0 Mmcfe/d
Capital Expenditures	
2017 Net Operational Capex	$115.0 - $130.0 million
2018 Net Operational Capex	$65.0 - $80.0 million

(1) As of December 31, 2016; does not include certain peripheral non-core acreage
(2) See notes on Page 2
(3) As of October 16, 2017
(4) Excludes Illinois Basin production
(5) Excludes Warrior South production

Rex Energy Milestones

Financial and Operational Milestones	
▪ BP Energy Company Marketing Arrangement	▪ Beginning January 1, 2018, BP Energy Company will purchase the majority of C3+ product stream with favorable pricing to actual and projected 2017 prices ▪ Mitigates historical seasonal fluctuations and stabilizes quarterly cash flows ▪ Reduction in outstanding letters of credit by approximately $14.1 million, immediately increasing liquidity
▪ Non-core Asset Sales	▪ June 2015 - Keystone Clearwater Solutions - $66 million in net proceeds ▪ June 2016 - Illinois Basin Assets - $40.0 million in net proceeds ▪ January 2017 - Warrior South Assets - $30.0 million in net proceeds ▪ July 2017 – Salineville waterline - $8.0 million in proceeds
▪ Joint Development Agreements	▪ March 2015 - Entered into a joint venture agreement with ArcLight Capital Partners to develop 32 wells in Butler Operated Area – reduced 2015 capital budget by $60 million ▪ March 2016 - Entered into joint development agreement with Benefit Street Partners (BSP) – BSP has committed ~$135.0 million to date; currently in discussions for future participation in additional wells
▪ Equitization of debt and preferred stock	▪ $28.7 million of Unsecured Notes and $43.5 million of 2nd Lien Notes ▪ $71.2 million of preferred stock ▪ ~$143.4 million of debt and preferred stock equitized to recapitalize balance sheet and reduce total leverage
▪ Marketing Initiatives	▪ Commencement of Gulf Coast transportation in 4Q16 of 50% of natural gas volumes from Butler Op. Area – provides premium pricing and reduction in overall differentials: 2016: $0.85 vs. 2017E: $0.35 - $0.45 ▪ Amended existing marketing contracts to align with production growth ▪ Maximized ethane transportation agreements
▪ First Lien Delayed Draw Term Loan	▪ $300 million first lien delayed draw term loan ▪ Initial borrowings of $143.5 million used to repay all outstanding loans and obligations under previous senior secured credit facility ▪ ~$110.0 million of additional capacity which will be available for development of core assets ▪ Ability to expand, under certain circumstances, up to an additional $100 million
▪ Two-Year Financial and Operational Outlook	▪ Estimated EBITDAX growth of over 150% by year-end 2018 ▪ Reduction in total debt to EBITDAX of 55% - 65% by year-end 2018 ▪ Estimated year-over-year production growth of 5% - 10% in 2017 and 31% - 36% in 2018 ▪ ~1,300 gross drilling locations will be entirely HBP'd by mid-2018

Future Liquidity Milestones

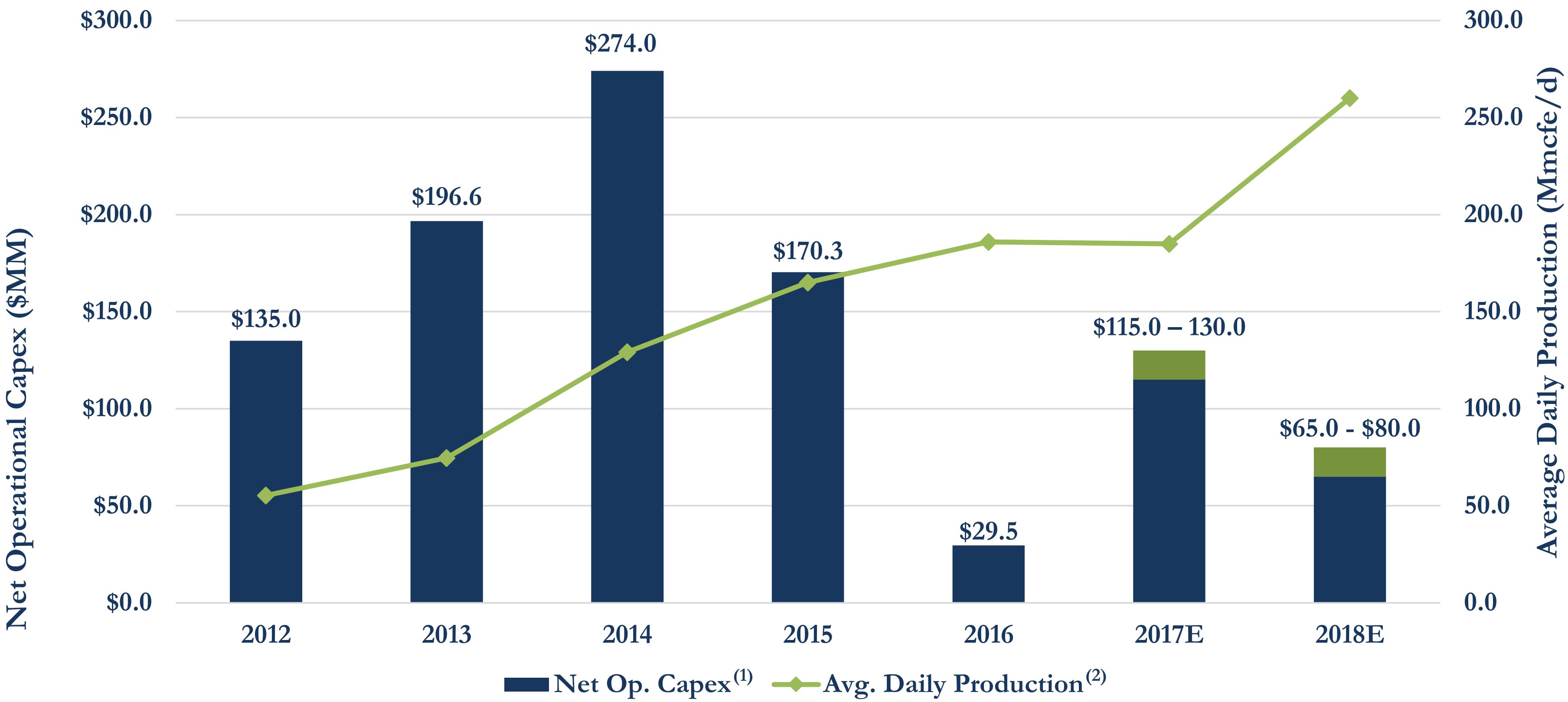
Current Initiatives/Future Milestones	
▪ Future non-core asset sales	▪ Western Lawrence Assets ▪ Westmoreland/Clearfield Assets
▪ Marketing Initiatives	▪ Opportunity for further enhancements to liquids pricing ▪ Improved gas marketing agreements in Butler Operated Area and Warrior North Area
▪ Reduction in letters of credit	▪ Potential to reduce letters of credit by ~$14 - $30 million ▪ Additional liquidity would be redeployed for further asset development
▪ Joint Development Agreements	▪ Additional participation in development program by Sumitomo, ArcLight and Benefit Street Partners

Rex can create an additional $40.0 - $75.0 million of liquidity, including annual EBITDAX enhancements of ~$5.0 million, from current initiatives that will be redeployed towards development of the company's assets and further execution of the two-year operational and financial plan

Operational Focus

Moraine East Area	
▪ Six-well Shields pad	▪ 24-hour sales rate per well of 9.2 Mmcfe/d ▪ 30-day sales rate per well of 7.9 Mmcfe/d ▪ In-line with economic projections for 2017 Moraine East program
▪ Four-well Mackrell pad	▪ Drilled to an average lateral length of ~7,630 ▪ 24-hour sales rate per well of 8.4 Mmcfe/d
▪ Two-well Frye pad	▪ Drilled to an average lateral length of ~6,300 feet ▪ 24-hour sales rate per well of 9.4 Mmcfe/d ▪ On a per lateral foot basis, highest rates achieved in Moraine East
▪ Four-well Baird pad	▪ 24-hour sales rate of 10.1 Mmcfe/d ▪ Two Marcellus wells produced at an average 24-hour sales rate per well fof 12.1 Mmcfe/d ▪ Baird 4H produced 213 bbls/d of condensate, representing the highest condensate rate achieved in the Butler Operated Area
▪ Three-well Manuel pad	▪ Drilled to an average lateral length of ~6,750 feet ▪ Expected to be placed into sales in 4Q17
▪ Renick compressor station pipeline	▪ Completed pipeline to Shields, Mackrell and Frye pads
Legacy Butler Operated Area	
▪ Four-well Wilson pad	▪ Drilled to an average lateral length of ~9,300 feet ▪ Initial 24-hour average sales rate per well of 10.9 Mmcfe/d
Warrior North Area	
▪ Three-well Jenkins pad	▪ Average lateral length of ~6,500 feet ▪ Expected to be placed into sales in 4Q17
▪ Seven-well Goebeler pad	▪ Average lateral length of 7,500 feet ▪ Currently drilling fifth well on the pad ▪ Expected to be placed into sales in 2Q18

Capital Efficient Production Growth

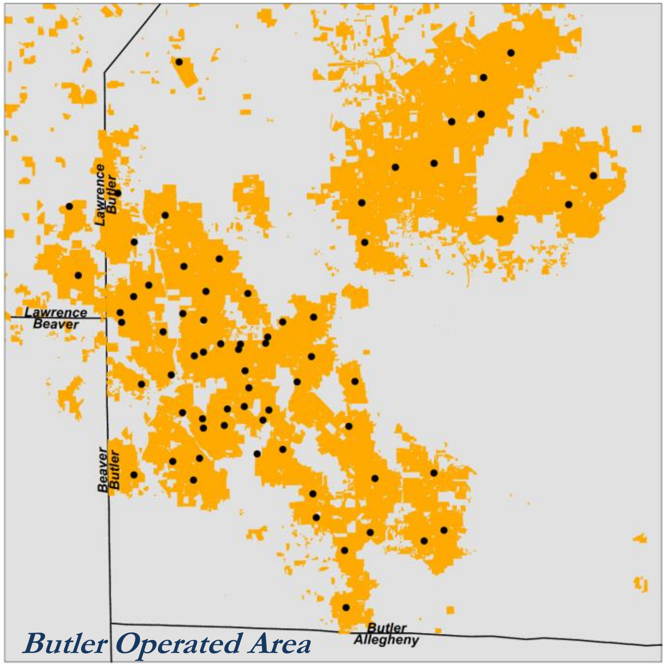


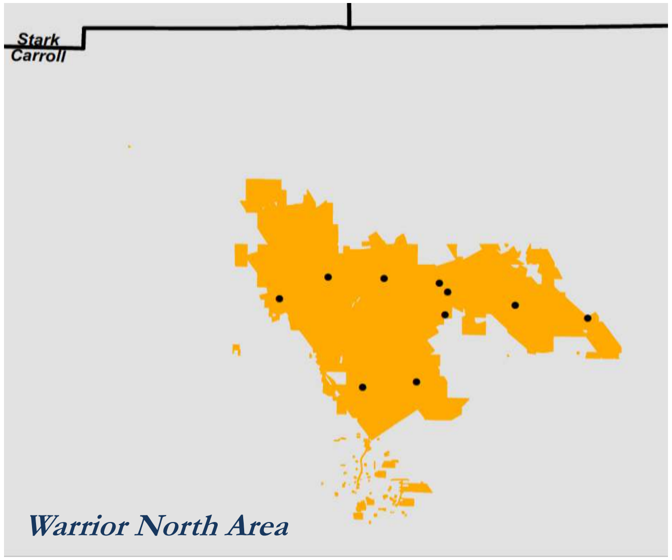
Rex's ability to grow production while reducing capital expenditures is due to various factors:

- Lower overall well costs due to reduced drilling days and more completions stages per day
- Enhanced completion design – increased sand loading per well
- Shallower declines on current wells
- Improved cycle times for four-well pads
- Joint development agreements reducing capital expenditures net to Rex Energy

(1) 2012 – 2016 net operational capital expenditures excludes capital related to the Illinois Basin and Warrior South assets, which were divested in 2016 and 2017, respectively
(2) 2012 – 2016 average daily production excludes production related to the Illinois Basin and Warrior South assets, which were divested in 2016 and 2017, respectively

Utilizing Existing Pads to Maximize Efficiency





- Utilizing existing pads and increased well density saves approximately $1.0 million per pad
  - Infrastructure already in place
  - Land/title work already complete
- Rex has over 75 existing pads in its Butler Operated Area and Warrior North Area
- 40% of 2017/2018 activity is from existing pad sites
- 69 pads have four or fewer wells and 9 pads have five or more wells
- Existing pad sites can accommodate up to 6 - 10 additional wells with the ability to target the Marcellus, Upper Devonian and Utica formations

COMPANY OVERVIEW

Midstream Capacity

Butler Operated Area	
▪ Processing Capacity	▪ 285 MMcf/d of total current processing capacity at MarkWest facilities ▪ Pipeline connects Moraine East production to MarkWest facilities

▪ Firm Transportation	▪ ~390 MMcf/d of current and future firm transportation from Bluestone Complex to multiple outlets
	▪ 130 MMcf/d of Gulf Coast transportation began on November 1, 2016
	  ▪ Allows for access to premium markets in the Midwest and Gulf Coast, including future LNG export facilities
	  ▪ Expect to transport approximately 50% of natural gas volumes to Midwest and Gulf Coast
	  ▪ For full-year 2017, expect overall basis differentials to improve by ~50% over full-year 2016 basis differentials

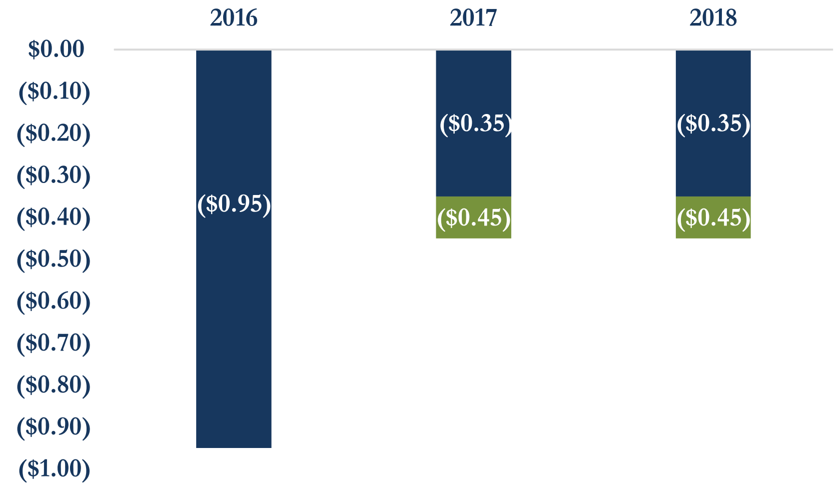
▪ Ethane Sales	▪ Mariner East – 2,000 bbls/d ▪ ATEX - 6,000 bbls/d ▪ Mariner West – 2,000 bbls/d
▪ C3+ Sales	▪ Marketed by MarkWest ▪ Beginning in 1Q17, selling 2,000 bbls/d of C3 & 1,000 bbls/d of C4 on Mariner East II
Warrior North Area	
▪ Processing capacity	▪ Acreage dedication to Blue Racer Midstream ▪ Processing capacity at Natrium facility (Blue Racer)
▪ Firm Transportation	▪ ~14 MMcf/d of residue gas firm transportation ▪ Access to Blue Racer super system to sell residue gas to the premium Midwest markets
▪ Ethane Sales	▪ Access to Mariner East I pipeline for ethane volumes

Natural Gas Differentials

Natural Gas Takeaway

- Gulf Coast transportation began on November 1, 2016, allowing access to premium Midwest and Gulf Coast markets
- Future LNG projects (2018/2019) in Gulf Coast region expected to increase demand
- Additional pipeline takeaway projects coming online in 2017/2018 are expected to strengthen local northeast pricing differentials

Natural Gas Differentials

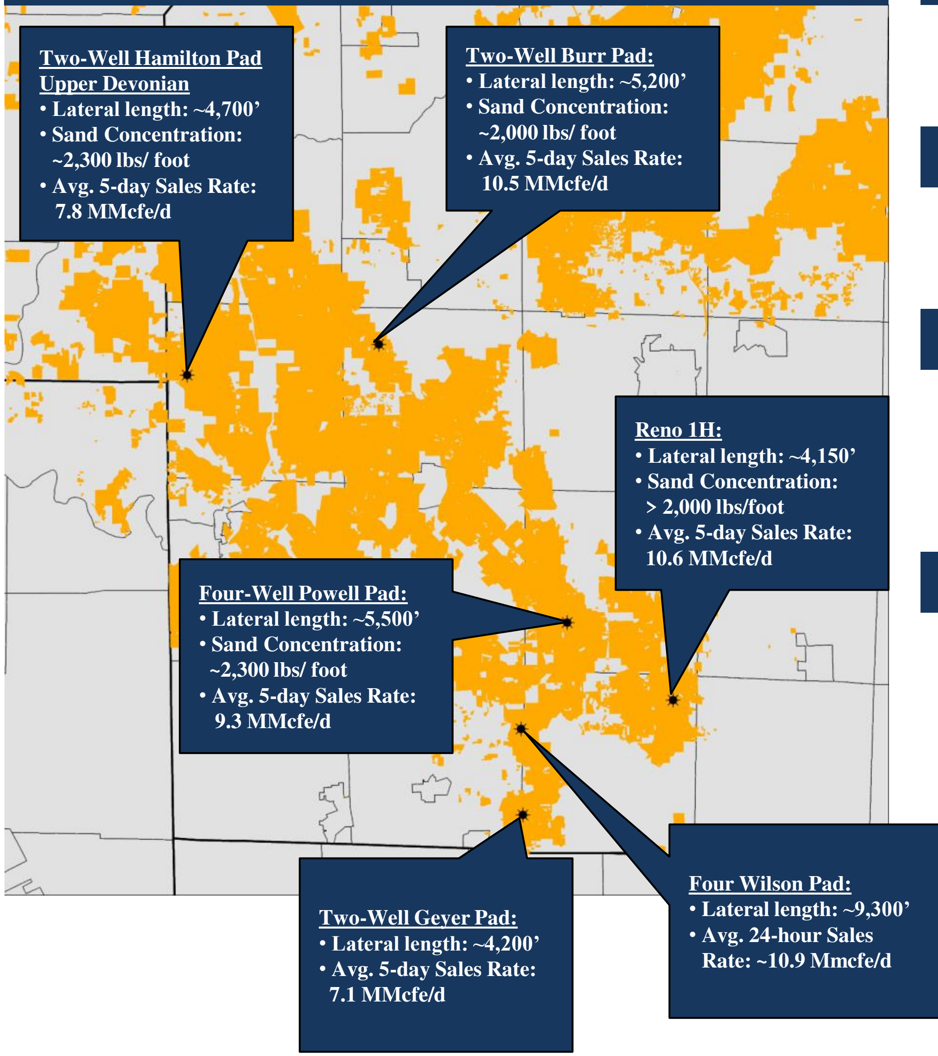


Natural Gas Pricing Arrangements

Region	% of 2017 Production	% of 2018 Production
Appalachia / Local Hedged	~37%	~37%
Gulf Coast	~53%	~46%
Appalachia / Local	~10%	~17%

Legacy Butler Operated Area

Legacy Butler Operated Area(1)

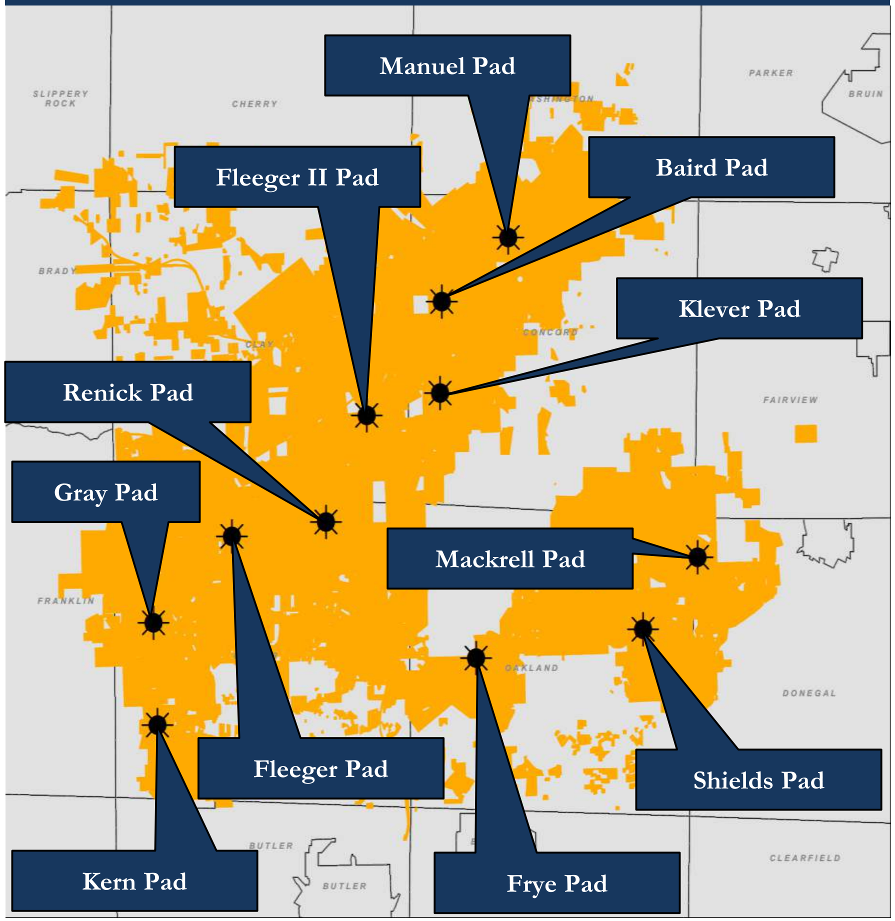


Total Acreage	
Total Gross / Net Acres	~62,000/~43,400
Average Working Interest	~70%
Potential Drilling Locations(2)(3)	
Gross/Net Identified Locations	825/578
Current Well Spacing	650’
2017 Activity Program	
Wells Drilled (Gross / Net)	4.0 / 2.8
Wells Completed (Gross / Net)	4.0 / 2.8
Wells PIS (Gross / Net)	4.0 / 2.8
2018 Activity Program	
Wells Drilled (Gross / Net)	4.0 / 2.8
Wells Completed (Gross / Net)	4.0 / 2.8
Wells PIS (Gross / Net)	4.0 / 2.8

(1) All production results are on a per well basis
(2) See note on Potential Drilling Locations on page 2
(3) Includes Burkett well counts from the Legacy Butler Operated Area

Moraine East Area

Moraine East Area



Total Acreage	
Total Gross / Net Acres	~36,000/~30,600
Average Working Interest	85%
Potential Drilling Locations[(1)(2)]	
Gross/Net Identified Locations	375/304
Current Well Spacing	650'
2017 Activity Program	
Wells Drilled (Gross / Net)	12.0 / 7.8
Wells Completed (Gross / Net)	17.0 / 7.7
Wells PIS (Gross / Net)	17.0 / 7.7
2018 Activity Program	
Wells Drilled (Gross / Net)	--
Wells Completed (Gross / Net)	4.0 / 4.0
Wells PIS (Gross / Net)	4.0 / 4.0

(1) See note on Potential Drilling Locations on page 2
(2) Includes Burkett well counts from the Moraine East Area

Moraine East Area – Recent Developments

▪ Six-well Shields pad	▪ 24-hour sales rate per well of 9.2 Mmcfe/d ▪ 30-day sales rate per well of 7.9 Mmcfe/d ▪ In-line with economic projections for 2017 Moraine East program
▪ Four-well Mackrell pad	▪ Drilled to an average lateral length of ~7,630 ▪ 24-hour sales rate per well of 8.4 Mmcfe/d
▪ Two-well Frye pad	▪ Drilled to an average lateral length of ~6,300 feet ▪ 24-hour sales rate per well of 9.4 Mmcfe/d ▪ On a per lateral foot basis, highest rates achieved in Moraine East
▪ Four-well Baird pad	▪ 24-hour sales rate of 10.1 Mmcfe/d ▪ Two Marcellus wells produced at an average 24-hour sales rate per well fof 12.1 Mmcfe/d ▪ Baird 4H produced 213 bbls/d of condensate, representing the highest condensate rate achieved in the Butler Operated Area
▪ Three-well Manuel pad	▪ Drilled to an average lateral length of ~6,750 feet ▪ Expected to be placed into sales in 4Q17
▪ Renick compressor station pipeline	▪ Completed pipeline to Shields, Mackrell and Frye pads
▪ Placed two-well Klever pad into sales	▪ Average 5-day sales rate of 10.4 Mmcfe/d ▪ Natural gas: 4.5 MMcf/d; NGLs: 895 bbls/d; Condensate: 81 bbls/d ▪ Average lateral length of ~7,460 feet

▪ Placed four-well Fleeger II pad into sales	▪ Three Marcellus wells & one Burkett well
	▪ Average 24-hour sales rate for three Marcellus wells of 10.4 Mmcfe/d
	    ▪ Natural gas: 4.3 MMcf/d; NGLs: 851 bbls/d; Condensate: 154 bbls/d
	▪ Average 24-hour sales rate for one Burkett well of 7.0 Mmcfe/d
	    ▪ Natural gas: 2.9 MMcf/d; NGLs: 557 bbls/d; Condensate: 133 bbls/d

Enhanced Performance[1]

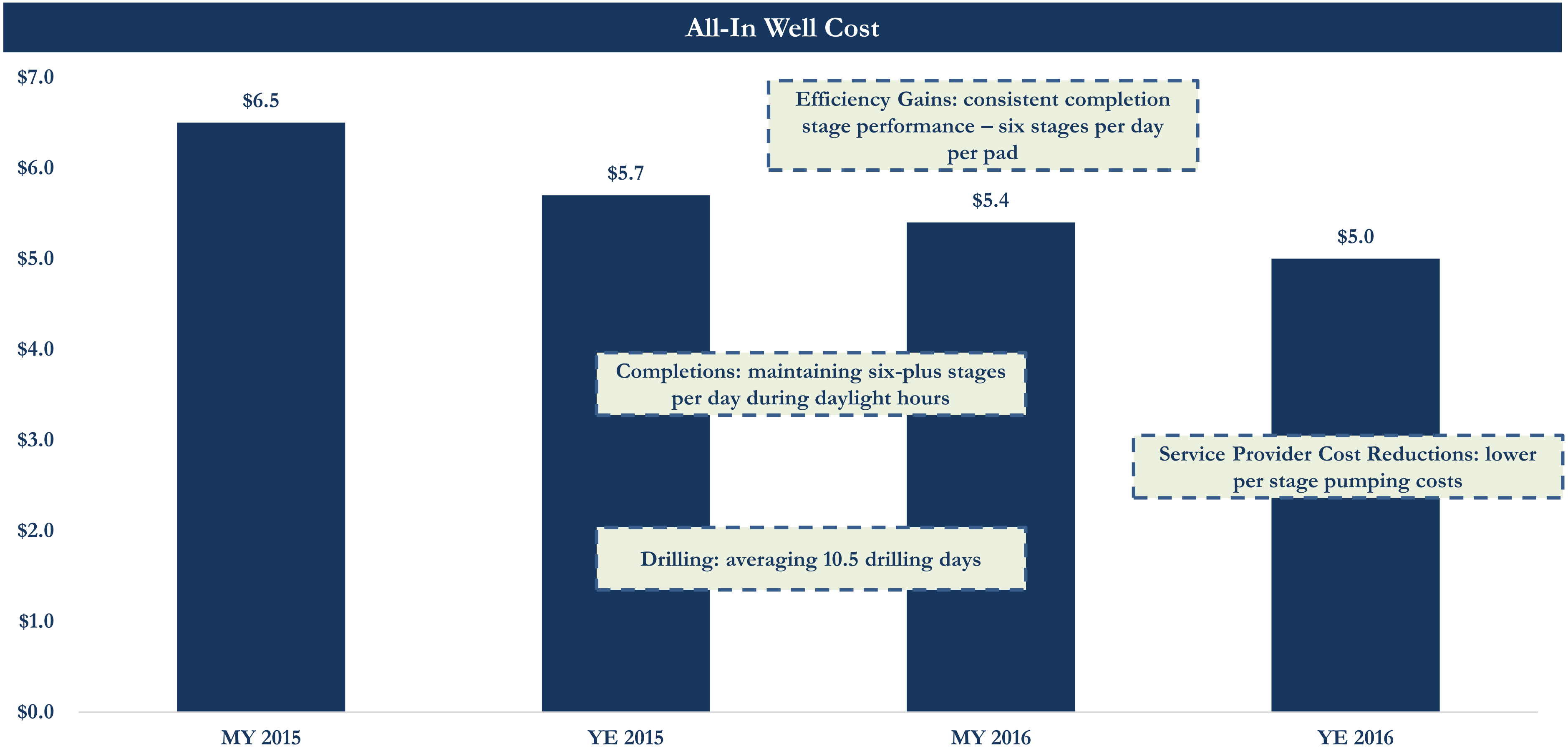
Rex Energy has been successful in improving the well design in its Butler Op. Area

	5.3 Bcfe EUR	7.0 Bcfe EUR	9.7 Bcfe EUR (80% ethane) / 8.9 Bcfe EUR (55% ethane)	11.7 Bcfe EUR (80% ethane) / 10.7 Bcfe EUR (55% ethane)	15.6 Bcfe EUR (80% ethane)[2] / 14.4 Bcfe EUR (55% ethane)
	2011	**2012**	**2013**	**2014**	**2015**
Completion	Conventional	Conventional	RCS	RCS	RCS
Gross Avg. 30-Day Wellhead Gas IP (Mcf/d)	2,235	3,142	3,175	3,683	4,736
1st Yr. Decline	66%	54%	50%	48%	44%
Lateral Length	3,500’	3,500’	4,000’	4,000’	5,000’
Stages / Spacing	12 / 300’	27 / 150’	27 / 150’	33 / 150’	33 / 150’
Frac Sand (#/ft)	1,300	1,500	1,800	2,000-2,200	2,200-2,500
All-In Cost	$5.3 million	$6.5 million	$5.9 million	$5.7 million	$4.8 million

(1) EUR reflects gross volumes
(2) 15.6 Bcfe EUR reflective of $50/bbl Oil, $3.00/Mmbtu gas

Cost Environment

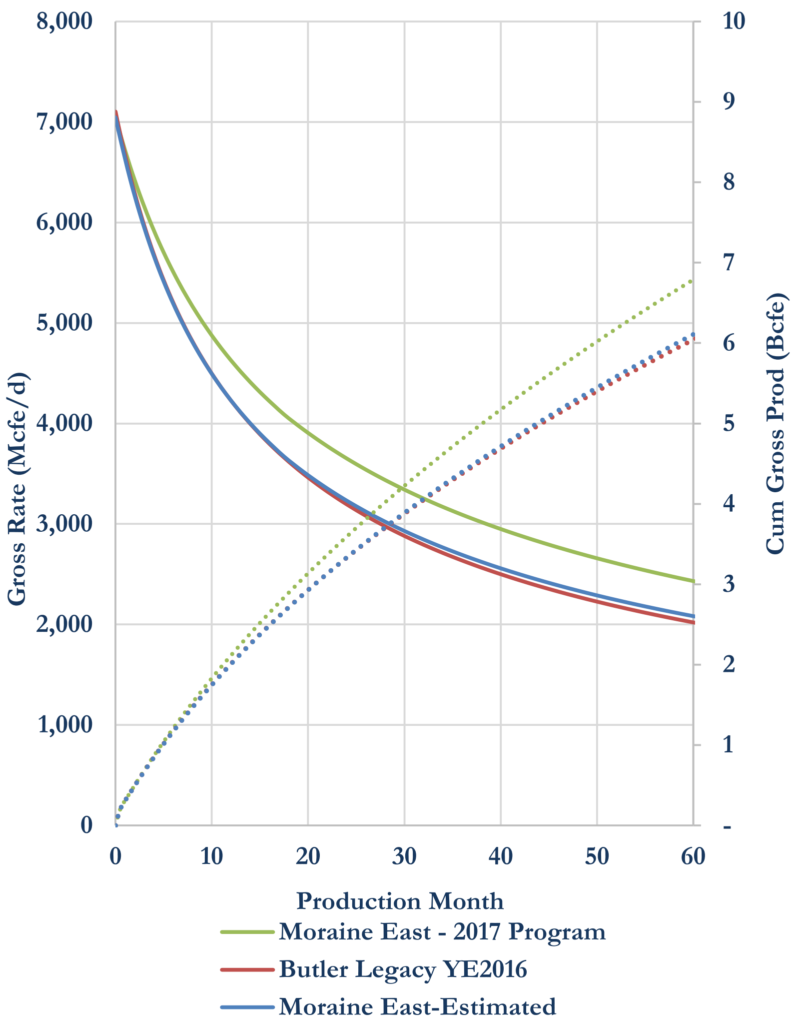
Rex Energy has successfully reduced the cost to drill and complete a 6,000' lateral by 23% over the last 18 months



All-In Well Cost for 5,000' lateral: $4.8 MM

Marcellus Economics[1]

Marcellus Economics (55% Ethane Recovery)[2]



		Butler Legacy – YE2016		Moraine East Estimated		Moraine East 2017 Program	
All-in Well Cost		$4.8 million		$5.0 million		$5.5 million	
Lateral Length		5,000 ft		6,000 ft		7,500 ft.	
EUR (Bcfe) 80% / 55% C2		15.6	14.4	16.4	15.1	18.5	17.1
F&D Cost ($/Mcfe)		$0.31	$0.33	$0.32	$0.35	$0.30	$0.32
IRR (3,4,5)	$3.00 NYMEX Oil Price: 2017+: $55	26%		32%		32%	
	$3.00 NYMEX Oil Price: 2017+: $50	23%		27%		28%	
	$3.25 NYMEX Oil Price: 2017+: $55	32%		37%		37%	
	Strip Pricing	26%		32%		32%	
Avg. 30-day sales rate (MMcfe/d)		5.0 – 8.0		5.0 – 8.0		6.0 – 9.0	

(1) *See note on Hydrocarbon Volumes and disclaimers at beginning of presentation.*
(2) *Economics reflect ≈55% ethane recovery.*
(3) *Average C3+ differential approx. 50% of Oil, C2 differential approx. is 13% of Oil.*
(4) *Historical price differentials applied to Condensate. Gas price differential dependent on future development plans and futures price differentials to Rex markets.*
(5) *Strip Pricing as of 02.13.2017 – Oil: 2017: $54.4, 2018: $55.17, 2019: $54.94, 2020: $54.89, 2021: $55.05// Gas: 2017: $3.2, 2018: $3.06, 2019: $2.87, 2020: $2.85, 2021: $2.85*

Moraine East Economics(1,2,3)

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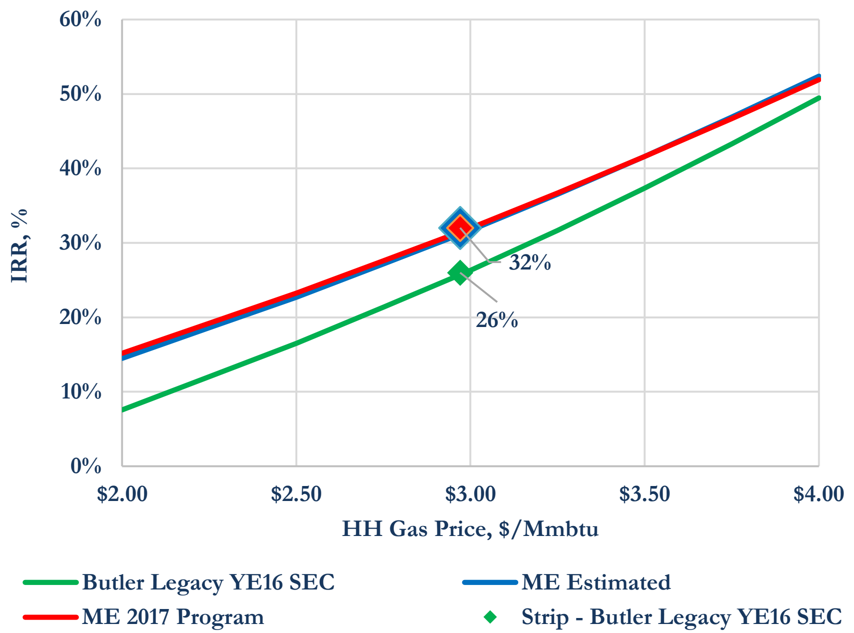
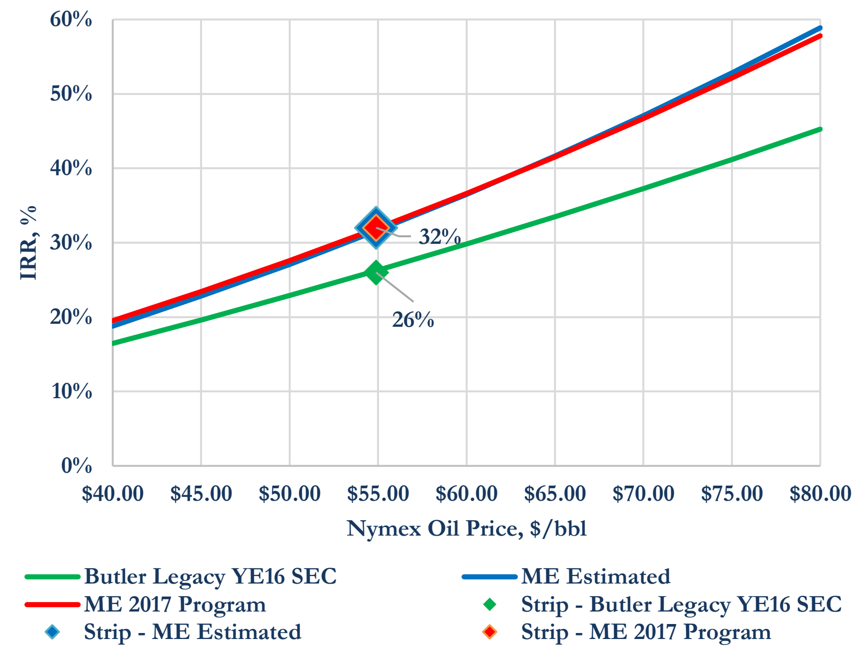
Before Tax IRR @ $55.00 / bbls



Before Tax IRR @ $3.00 / Mmbtu



Assumptions	Butler Legacy – YE2016	Moraine East Estimated	Moraine East 2017 Program
Lateral Length	5,000 feet	6,000 feet	7,500 feet
Drill & Complete	$4.8 million	$5.0 million	$5.5 million
30-Day IP Rate	6,877 Mcfe/d	6,829 Mcfe/d	6,876 Mcfe/d
EUR (Bcfe) 80% / 55% C2	15.7 / 14.5	16.4 / 15.1	18.5 / 17.1

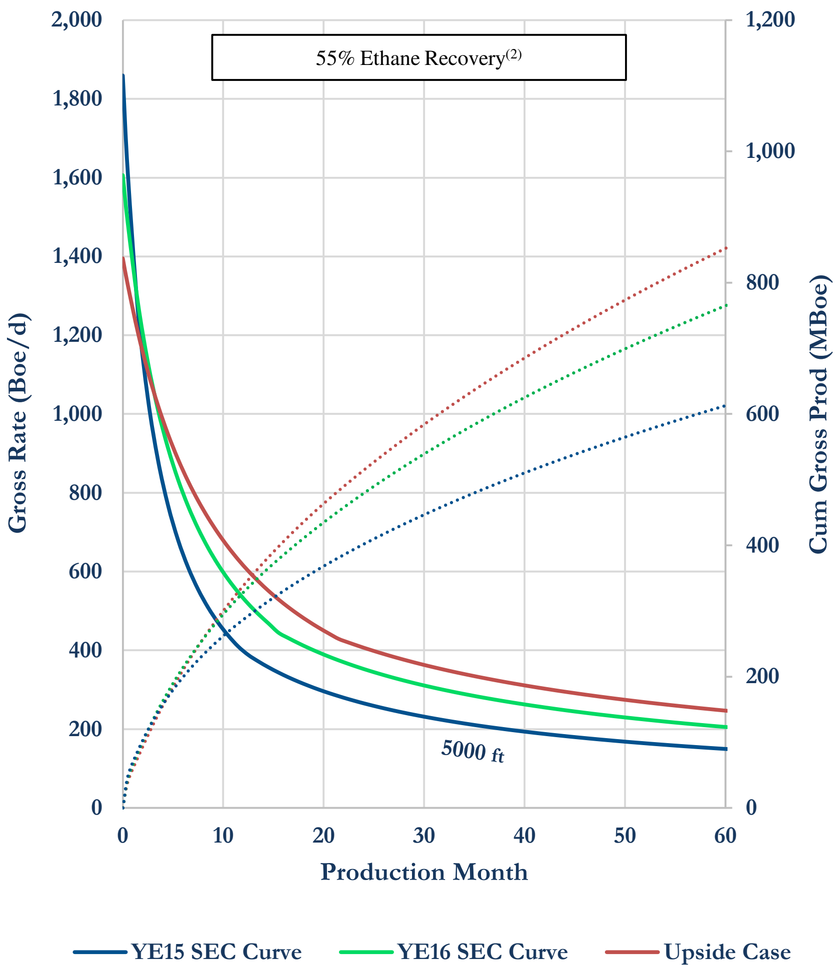
(1) C2 and C3+ NGL prices indexed at 11% and 51% of oil, respectively during the first year strip.
(2) Assumes 55% Ethane Recovery.
(3) Strip Pricing as of 02.13.2017 – Oil: 2017: $54.4, 2018: $55.17, 2019: $54.94, 2020: $54.89, 2021: $55.05// Gas: 2017: $3.2, 2018: $3.06, 2019: $2.87, 2020: $2.85, 2021: $2.85

Warrior North Area

Warrior North Area

Total Acreage	
Total Gross / Net Acres	~13,700/~12,400
Average Working Interest	95%
Potential Drilling Locations	
Gross/Net Identified Locations	58/48
Current Well Spacing	650’
2017 Activity Program	
Wells Drilled (Gross / Net)	12.0 / 10.2
Wells Completed (Gross / Net)	6.0 / 6.0
Wells PIS (Gross / Net)	3.0 / 3.0
2018 Activity Program	
Wells Drilled (Gross / Net)	1.0 / 0.8
Wells Completed (Gross / Net)	7.0 / 5.0
Wells PIS (Gross / Net)	10.0 / 8.0

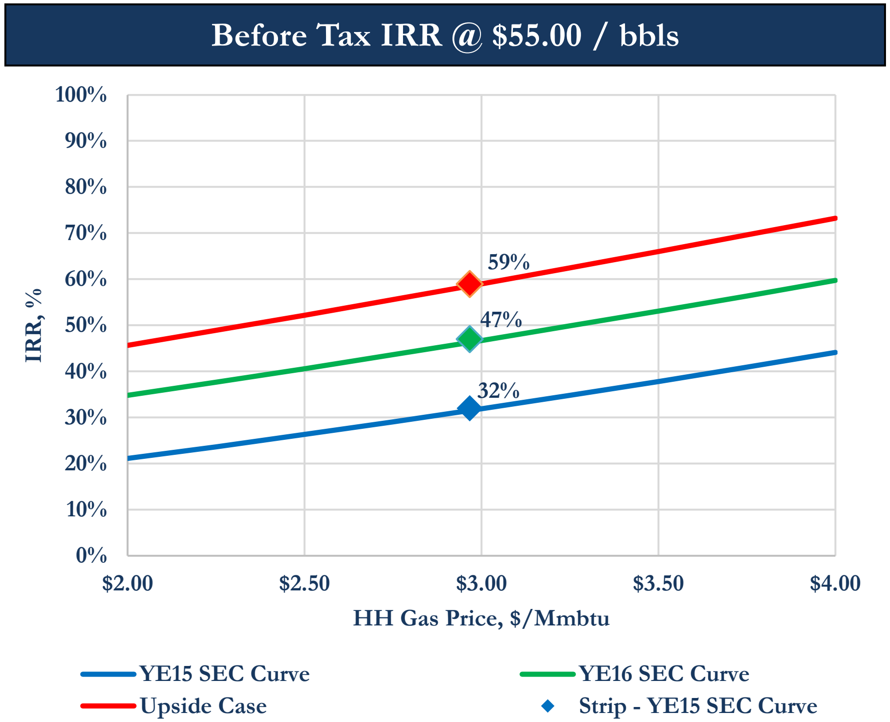
Warrior North Economics[1]

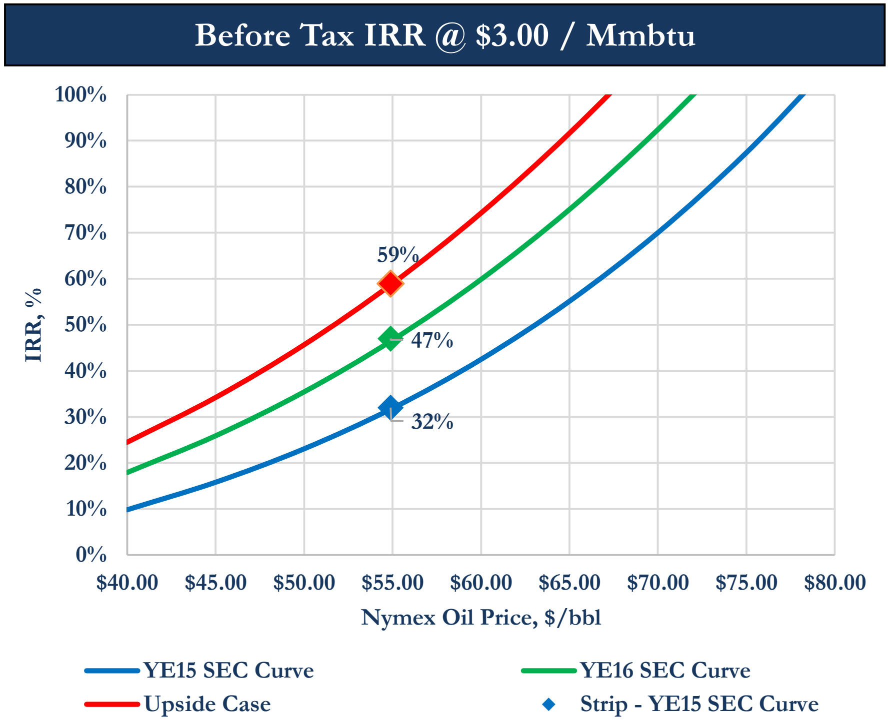


		YE15–SEC Curve	YE16–SEC Curve	Upside Case 2017
All-in Well Cost		$5.5 million	$6.2 million	$6.2 million
Lateral Length		5,000 ft	6,500 ft	6,500 ft
EUR (MMBOE)		1.2	1.6	1.9
F&D Cost ($/BOE)		$4.55	$3.89	$3.32
IRR (3,4,5)	$3.00 NYMEX Oil Price: 2017+: $55	32%	47%	59%
	$3.00 NYMEX Oil Price: 2017+: $50	23%	35%	46%
	$3.25 NYMEX Oil Price: 2017+: $55	35%	50%	62%
	Strip Pricing	32%	47%	59%
Avg. 30-day sales rate (MBOE/d)		1.4 – 1.8	1.3 – 1.7	1.1 – 1.5

(1) *See note on Hydrocarbon Volumes and disclaimers at beginning of presentation.*
(2) *Economics reflect ≈ 55% ethane recovery.*
(3) *Historical price differentials applied to Condensate. Futures differentials applied for gas production for all scenarios.*
(4) *C2 and C3+ NGL prices indexed at 17% and 54% of oil, respectively during the first year strip.*
(5) *Strip Pricing as of 02.13.2017 – Oil: 2017: $54.4, 2018: $55.17, 2019: $54.94, 2020: $54.89, 2021: $55.05// Gas: 2017: $3.2, 2018: $3.06, 2019: $2.87, 2020: $2.85, 2021: $2.85*

Warrior North Economics(1,2,3)



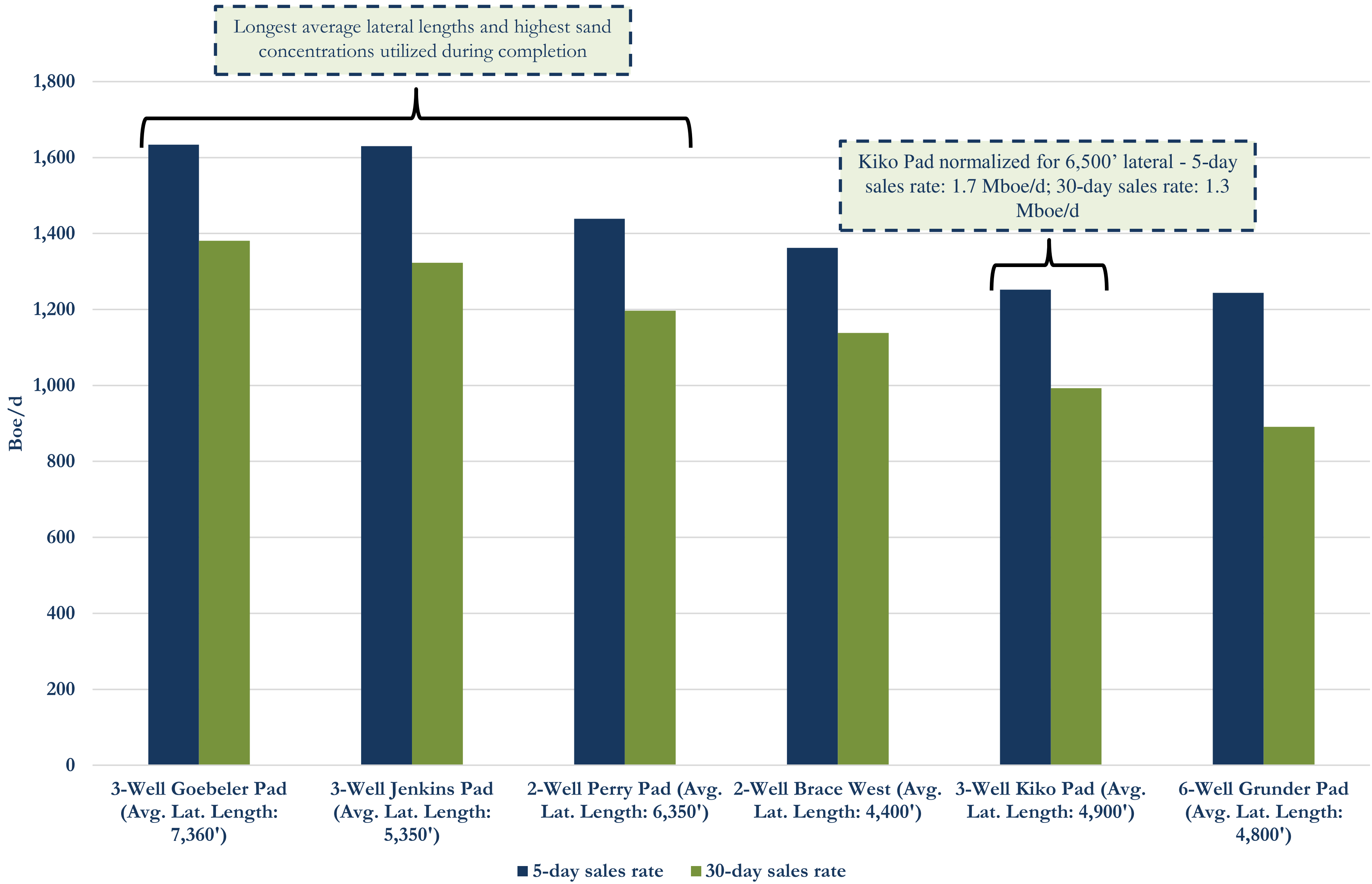


Assumptions	YE15 SEC Curve	YE16 SEC Curve	Upside Case
Lateral Length	5,000 feet	6,500 feet	6,500 feet
Drill & Complete	$5.5 million	$6.2 million	$6.2 million
30-Day IP Rate	1,611 Boe/d	1,484 Boe/d	1,327 Boe/d
EUR	1.2 Mmboe	1.6 Mmboe	1.9 Mmboe

(1) C2 and C3+ NGL prices indexed at 17% and 54% of oil, respectively during the first year strip.
(2) Assumes 55% Ethane Recovery.
(3) Strip Pricing as of 02.13.2017 – Oil: 2017: $54.4, 2018: $55.17, 2019: $54.94, 2020: $54.89, 2021: $55.05// Gas: 2017: $3.2, 2018: $3.06, 2019: $2.87, 2020: $2.85, 2021: $2.85

Warrior North Well Results

Longer laterals and enhanced completion design driving increased production rates



APPENDIX

Hedge Position[1] – Natural Gas

Natural Gas Hedge Position (Mcf)	2017	2018
Swap Contracts		
Volume	4,040,000	15,335,000
Price	$3.10	$3.10
Collar Contracts with Short Puts		
Volumes	4,550,000	10,600,000
Ceiling	$3.86	$3.52
Floor	$2.98	$2.90
Short Put	$2.29	$2.33
Collar Contracts		
Volume	500,000	450,000
Ceiling	$3.47	$3.65
Floor	$2.93	$3.20

(1) Hedging position as of 9/14/2017; percent hedged based on forecasted production

Hedge Position[1] – Natural Gas Liquids

NGL Hedge Position (Bbls)	2017	2018
Propane (C3) – Swap Contracts		
Volume (Bbls)	243,000	630,000
Price	$23.30	$25.62
Butane (C4) – Swap Contracts		
Volume	60,000	186,000
Price	$28.54	$32.94
Isobutane (IC4) – Swap Contracts		
Volumes	30,000	102,000
Price	$29.19	$33.62
Natural Gasoline (C5+) – Swap Contracts		
Volume	76,000	207,072
Ceiling	$48.83	$49.42
Ethane (C2) – Swap Contracts		
Volume	225,000	1,150,000
Price	$10.58	$12.97

(1) Hedging position as of 9/14/2017; percent hedged based on forecasted production

Hedge Position[1] – Condensate

Condensate Hedge Position (Bbls)	2017	2018
Swap Contracts		
Volume (Bbls)	15,000	60,000
Price	$54.00	$54.00
Collar Contracts		
Volumes	-	18,000
Ceiling	-	$60.00
Floor	-	$53.00
Collar Contracts with Short Puts		
Volume	39,000	66,000
Ceiling	$61.35	$61.55
Floor	$49.23	$51.59
Short Put	$39.62	$42.50

(1) Hedging position as of 9/14/2017; percent hedged based on forecasted production

Hedge Position[1] – Natural Gas Basis Differentials

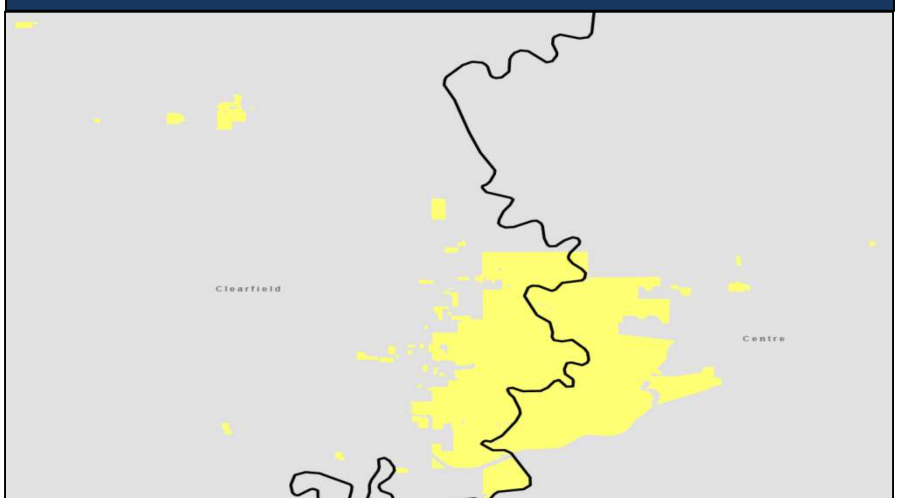
Natural Gas Basis Differential (Mcf)	2017	2018
Dominion Appalachia – Swap Contracts		
Volume (Bbls)	4,919,000	18,980,000
Price	($0.79)	($0.81)
Texas Gas Zone I		
Volume	3,680,000	14,600,000
Price	($0.13)	($0.13)

(1) Hedging position as of 9/14/2017; percent hedged based on forecasted production

Non-Operated Appalachia

Non Operated – Westmoreland County, PA

Non Operated – Clearfield / Centre Counties



Non-Operated Overview

- Sizable acreage position in Westmoreland, Clearfield and Centre Counties, PA
  - ~ 25,400 gross / ~ 10,200 net
- Combined average production for a recent 5-day period – 36.6 MMcf/d
- 7.0 gross MMcf/d firm capacity with interruptible takeaway into Columbia gas line in Clearfield/Centre Counties

Total Acreage

Total Net Acres	~10,200
Average Working Interest	40%

Butler Operated Area – Stacked Pays