Bill Barrett Corporation

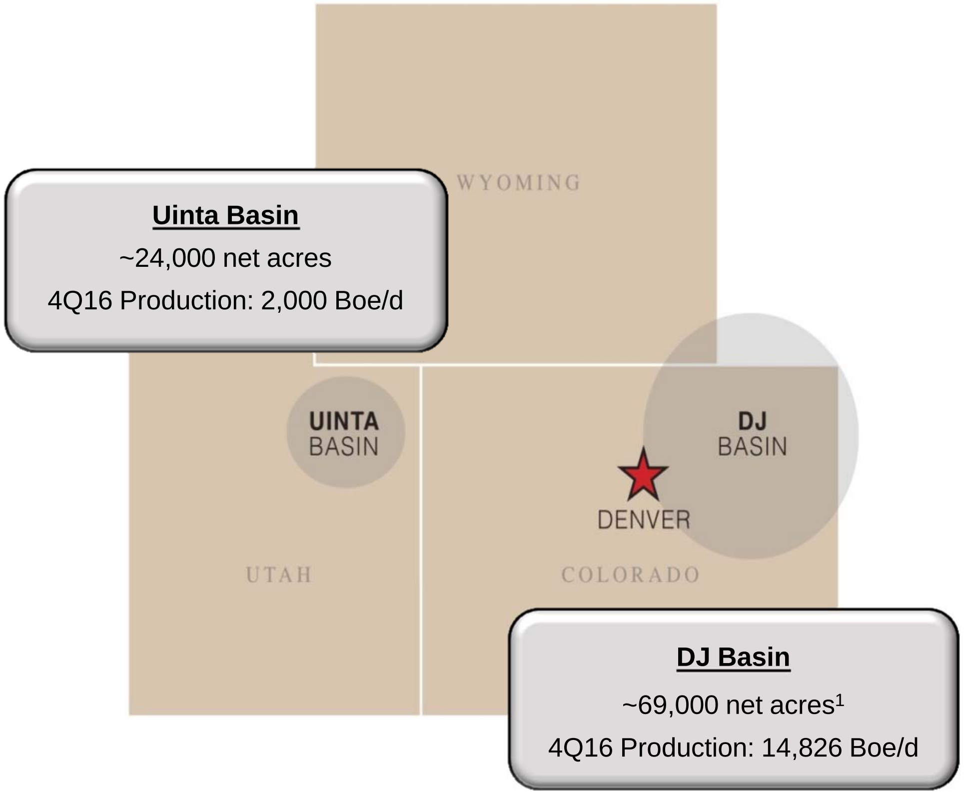
CORPORATE UPDATE

MARCH 2017

COMPANY OVERVIEW

Bill Barrett Corporation Overview

- **Large, contiguous acreage position within two core basins**
- **Highly efficient drilling and completion operations**
  - Enhancing results by incorporating improved wellbore construction and completion techniques
- **Executing operational program**
  - Early recognition of benefits of XRL well development
  - Increasing XRL well efficiencies
- **Financially well-positioned with significant cash position and liquidity**



[1] *Pro forma for acreage acquisition completed during the first quarter of 2016*

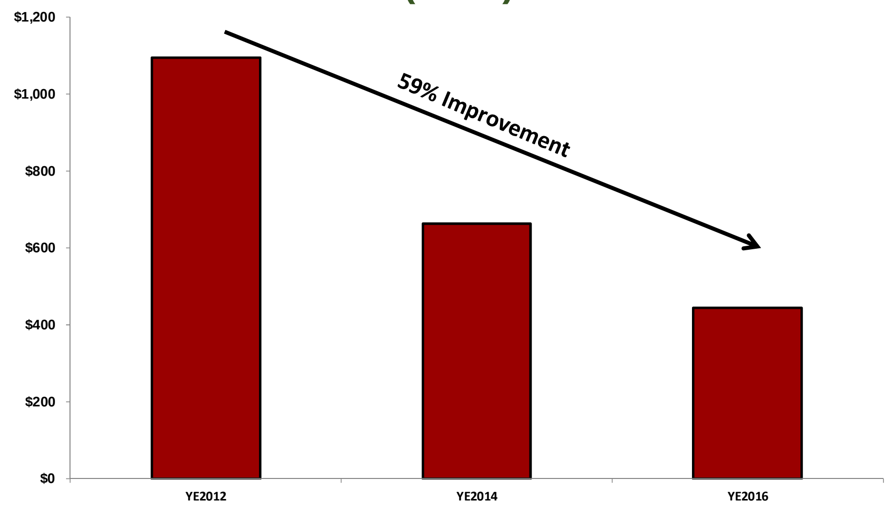
Key Messages

- **Demonstrated execution of focused operational and financial strategy**
  - Translates into solid results and strong margins
- **NE Wattenberg generates attractive well economics**
  - Addition of second drilling rig accelerates development pace
  - Strengthens production and financial profile for 2017 and 2018
- **Have the capital resources to facilitate growth strategy**
  - Cash position of ~$276 million at December 31, 2016 plus $300 million undrawn credit facility
- **Delivered continued improvement across corporate structure in 2016**
  - LOE of $4.58 per Boe, represents 29% improvement
  - DJ Basin LOE average $3.41 per Boe, represents 27% improvement
  - G&A per Boe reduced 21% over 2015
  - DJ Basin oil price differential narrowed to $3.45 per barrel, represents 58% improvement
- **Capital program designed to maintain operational and financial flexibility**
  - Ability to adjust capital program if necessary to respond to changes in commodity price
  - No long-term drilling, completion or oil marketing commitments
  - Acreage position is largely held by production

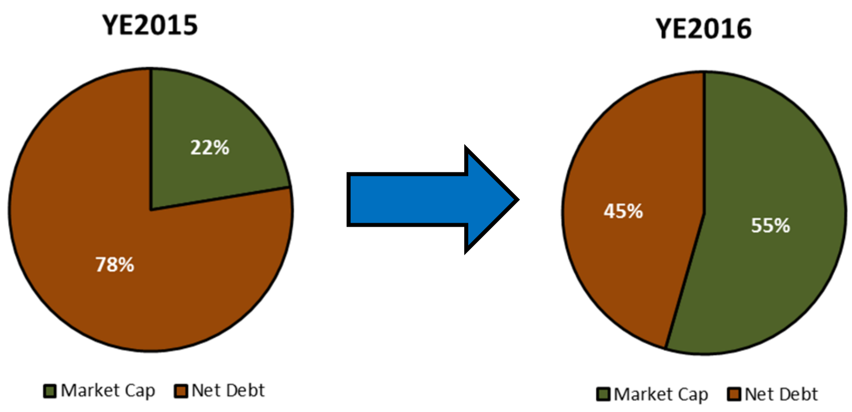
Debt Reduction Leads to Improved Capital Structure

- **Significant debt reduction accomplished in challenging commodity price environment**
- **Undrawn credit facility with borrowing base of $300 million**
  - No anticipated need to draw on revolver in 2017
- **Nearest debt maturity is not until 2019; net debt/EBITDAX ratio of 2.4x at December 31, 2016**
- **Improved market capitalization**

Net Debt ($mm)

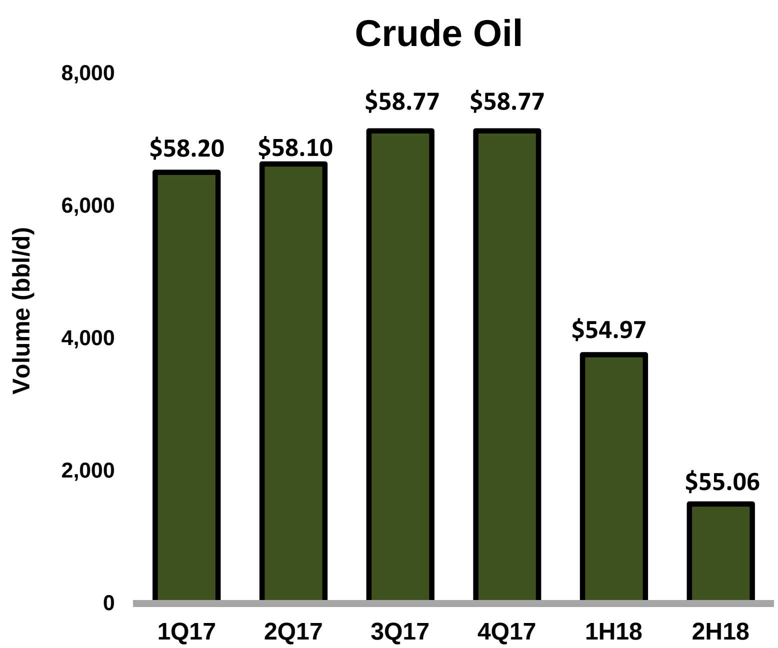


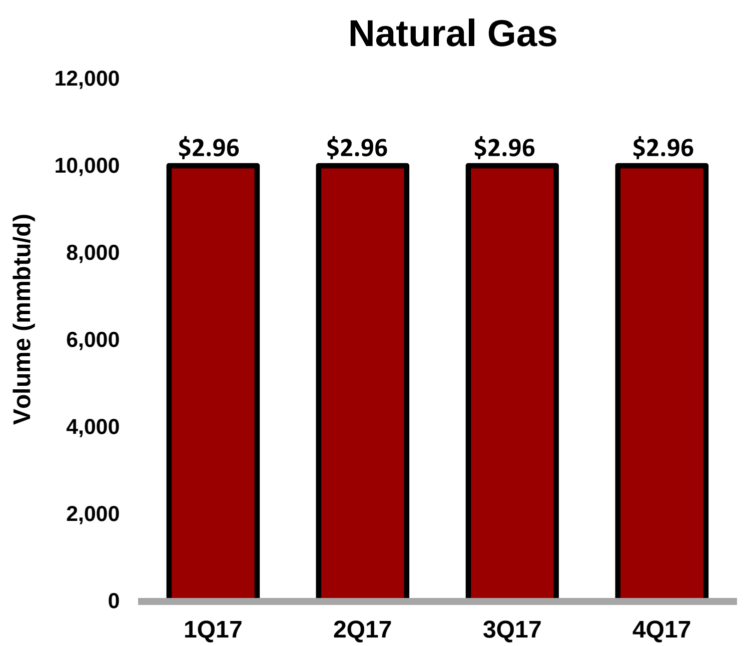
Enterprise Value



Hedging Program Protects Cash Flow

- **Actively manage hedge portfolio to support capital program, protect future cash flow and reduce commodity price risk**
- **Strategy is to hedge 50-70% of production on a forward 12-month to 18-month basis**
  - 2017: 6,846 Bbls/d of crude oil hedged at an average WTI price of $58.47/Bbl[1]
  - 2018: 2,616 Bbls/d of crude oil hedged at an average WTI price of $55.00/Bbl[1]
- **2018 hedge program expanded to support increased drilling activity**





[1] *Hedge position as of March 13, 2017*

2017 Guidance and Outlook

Designed to deploy capital with attractive returns, while maintaining flexibility

- **Capital expenditures range of $255-$285 million**
  - Guidance reflects additional drilling rig starting in the second quarter and recent acreage acquisition
- **Total production of 6.0-6.5 MMBoe**
  - Represents 7% production growth at the mid-point compared to pro forma 2016 production
  - 1Q17 production expected to approximate 1.35-1.45 MMBoe
- **Lease operating expense of $27-$30 million**
- **General and administrative expense of $30-$33 million[1]**
- **Gathering, transportation and processing costs of $2-$3 million**
- **2017 activity expected to deliver 2018 production growth of 30-50%**

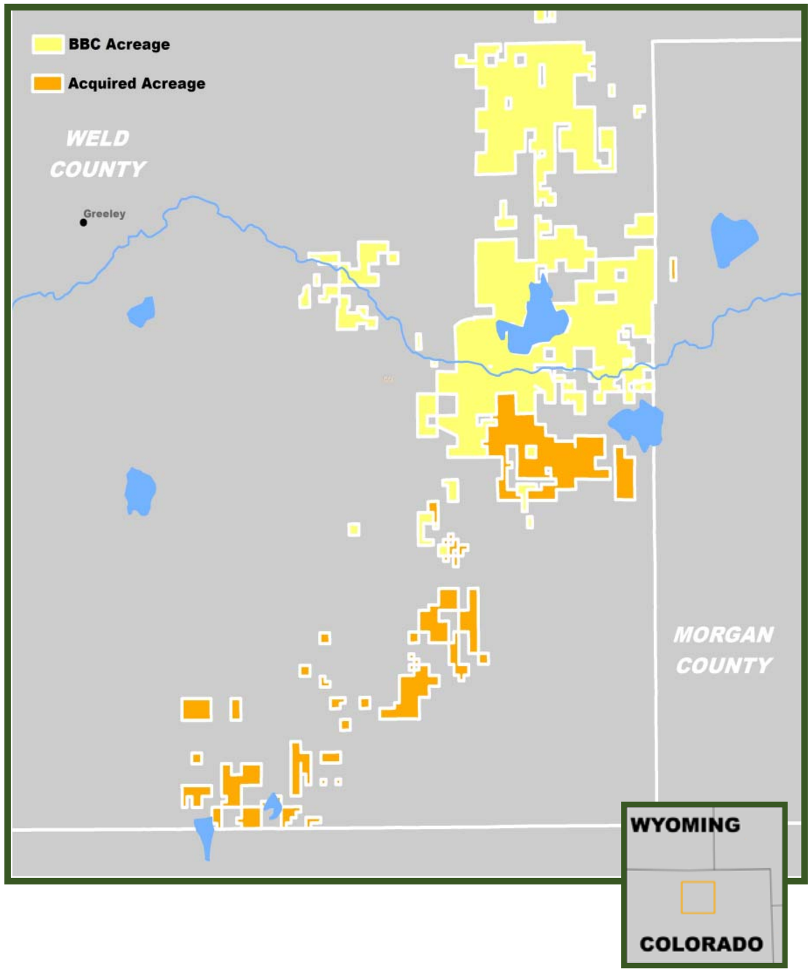
[1] *Excludes non-cash, performance-based compensation and one-time costs*

OPERATIONAL OVERVIEW

DJ Basin Provides Strategic Advantage

- **Large, contiguous acreage position provides substantial development opportunity**
  - ~69,000 total net acres favorable for XRL development[1]
  - Targeted development of stacked-pay horizons within Niobrara formation
    - o Drilling depth of ~6,000' with ~9,500' lateral for an XRL well
  - Core and seismic analysis confirms consistent geologic setting across acreage position
- **NE Wattenberg provides focused extended reach lateral ("XRL") horizontal development**
  - ~61,500 net acres in NE Wattenberg[1]
  - ~80% of acreage can be developed with XRL wells in 1,280-acre drilling spacing unit
- **Increased footprint through bolt-on acquisition**
  - Adds 13,800 net acres at attractive average cost
  - Contains ~80 operated XRL drilling locations and increased ownership in ~20 additional XRL locations

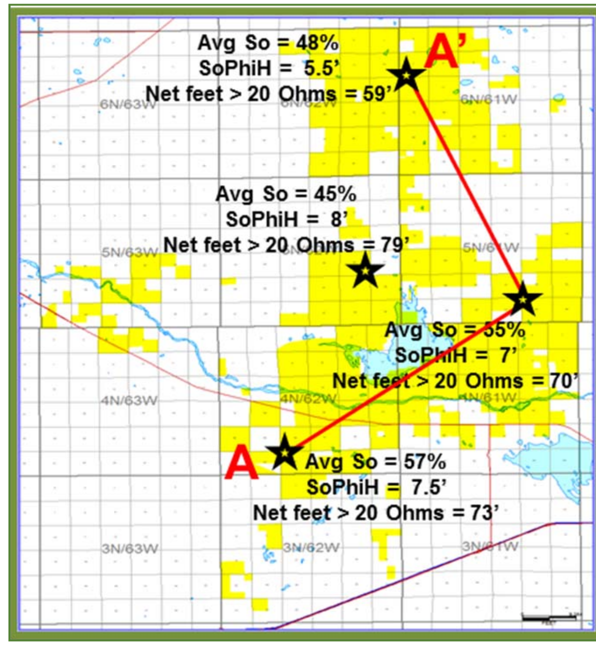
NE Wattenberg

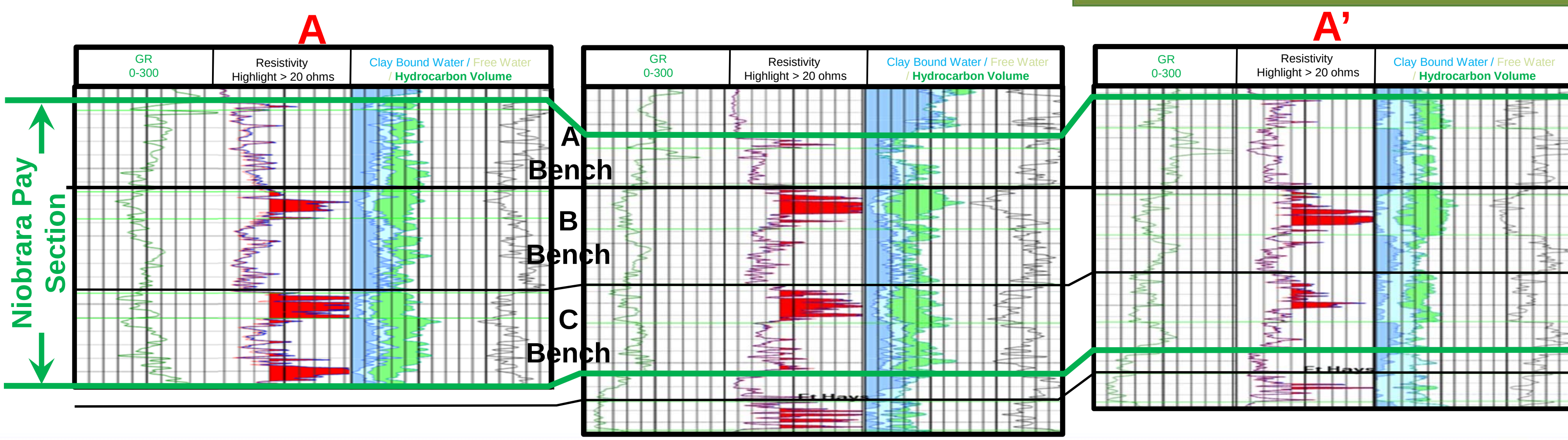


[1] *Includes 13,000 net acres associated with recent acreage acquisition*

NE Wattenberg Cross Section

- **Detailed core analysis confirms reservoir and resource quality is consistent**
  - Over 920’ of core was analyzed from four distinct well locations throughout acreage position
  - Strong average oil saturations (So) across acreage = 45%-57%
- **Nine mineral petrophysical model calibrated from core data for more accurate reservoir and resource assessment**
  - Calculated oil saturated pore volume (SoPhiH), an indicator of resource in place, is consistent with range = 5.5’-8’
  - Net footage of resistivity greater than 20 Ohms, an indicator of overall hydrocarbon charge, is also fairly consistent, with a range of 59’-79’

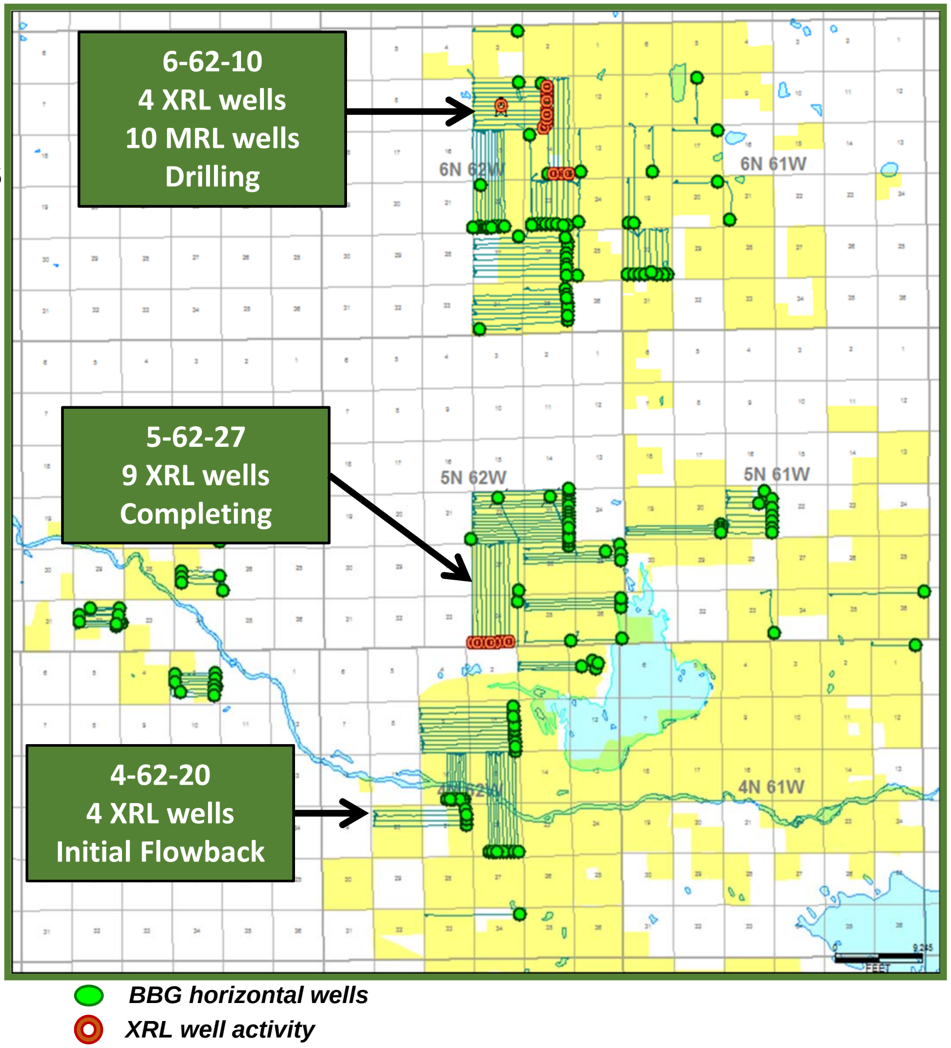




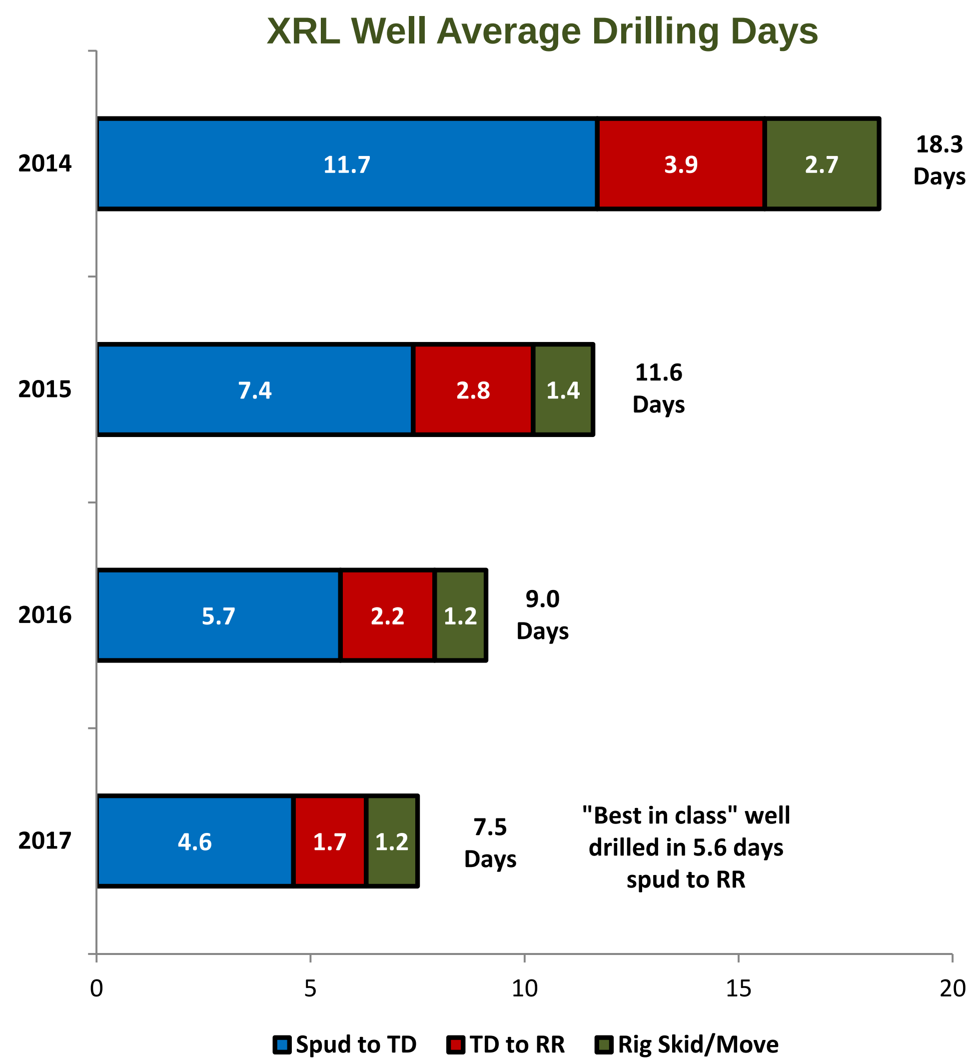
NE Wattenberg Focus Area

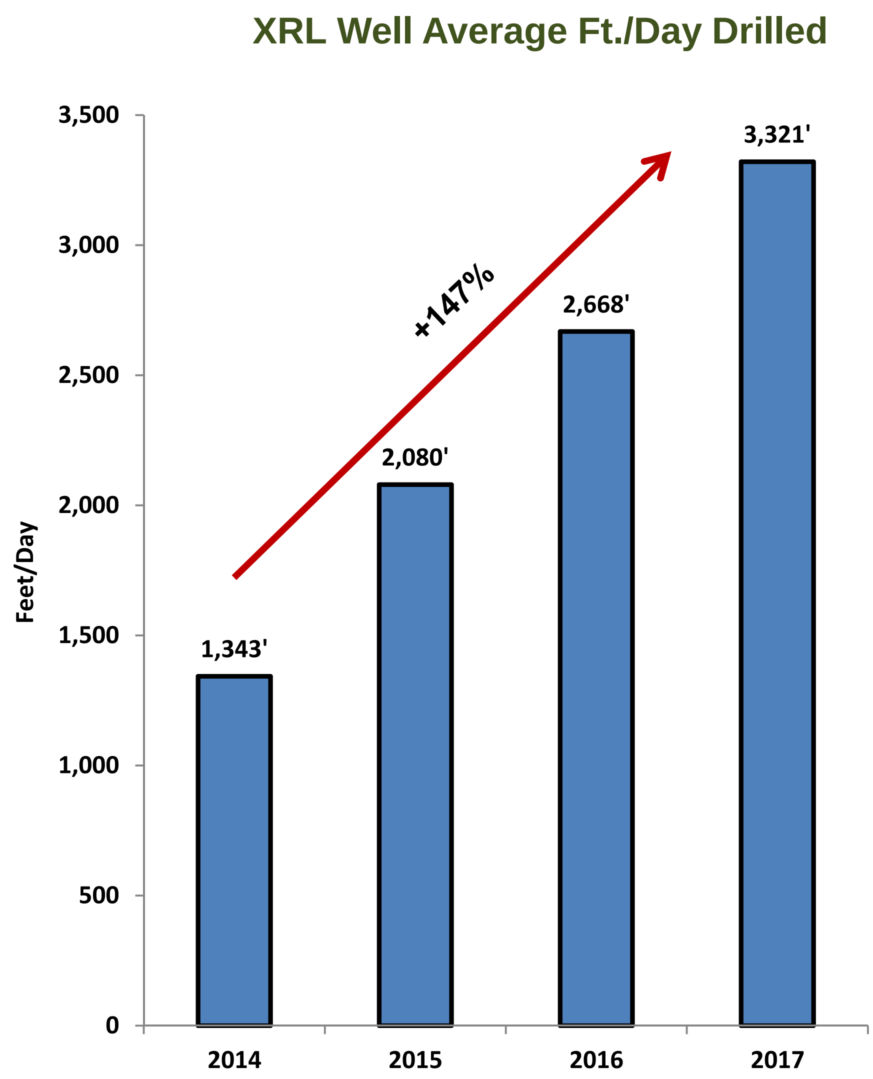
- **Early adopters recognizing economic benefit of XRL development**
- **Targeted development of Niobrara horizons throughout acreage position**
  - Section 4-62-20 (4 XRL wells)
    - o Enhanced proppant
    - o Initial flowback
  - Section 5-62-27 (9 XRL wells)
    - o Enhanced proppant & monobores
    - o Currently completing
  - Section 6-62-10 (4 XRL wells, 10 MRL wells)
    - o Enhanced proppant
    - o Currently drilling
- **XRL program generates competitive economics in current pricing environment**

NE Wattenberg Focus Area



Enhancing XRL Cost Efficiencies





Operational Execution Delivering Growth

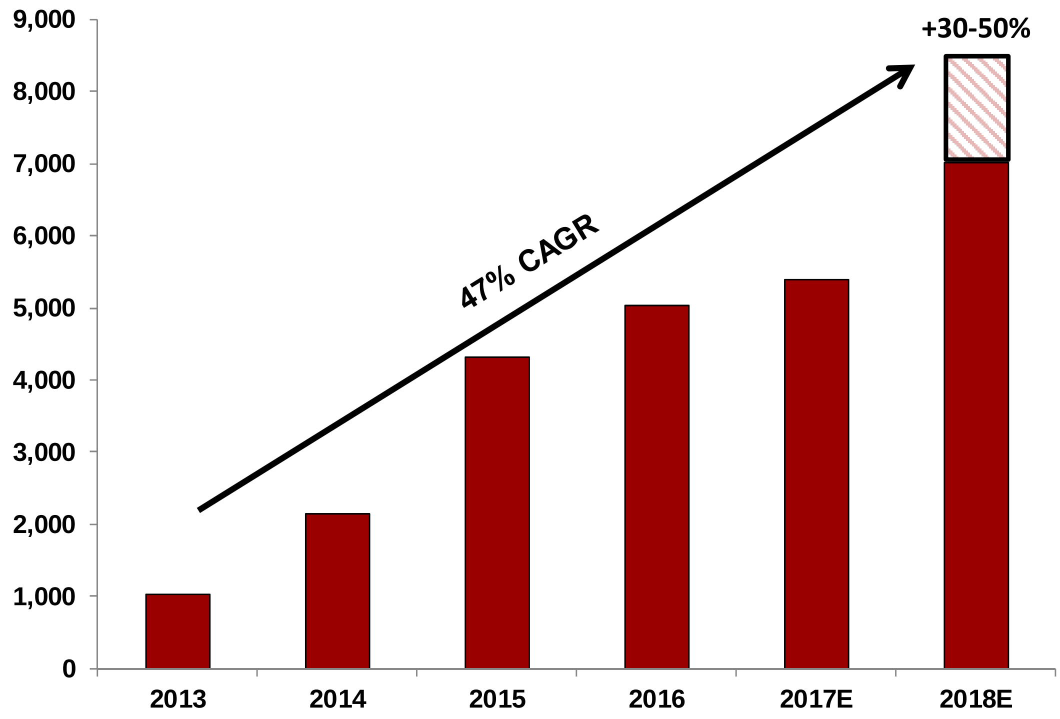
Track record of delivering sustained production growth

- Have maintained positive operational momentum in challenging environment
- Growing 2017 production volumes, while efficiently managing capital expenditures
- Expecting 30-50% growth in 2018

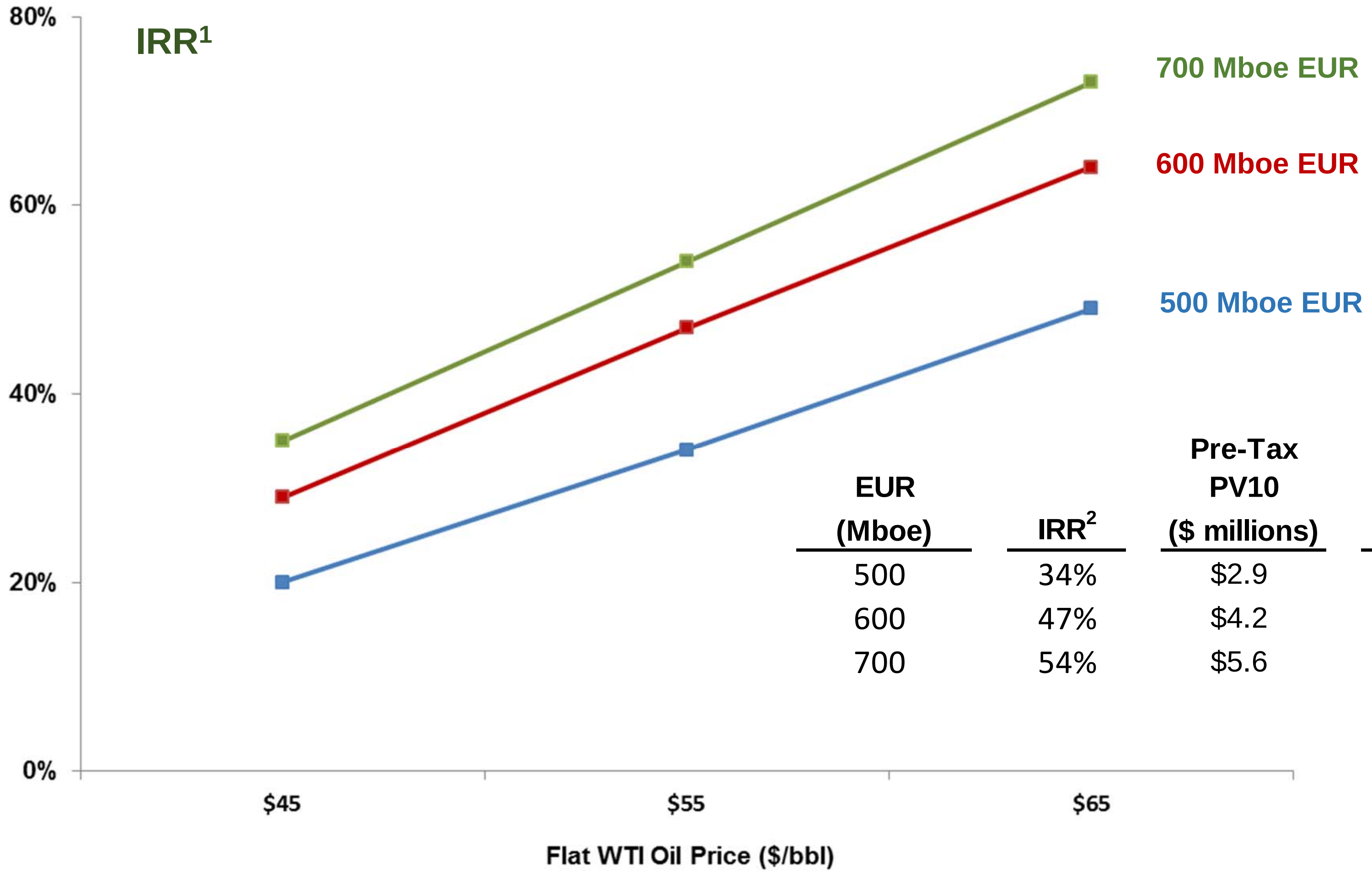
Optimizing well construction techniques through time to enhance operational returns

- Implementing new completion concepts to enhance results and economic returns
- Pursuing capital efficiency measures designed to improve well cots

DJ Basin
Net Sales Volumes (Mboe)



DJ Basin XRL Indicative Economics

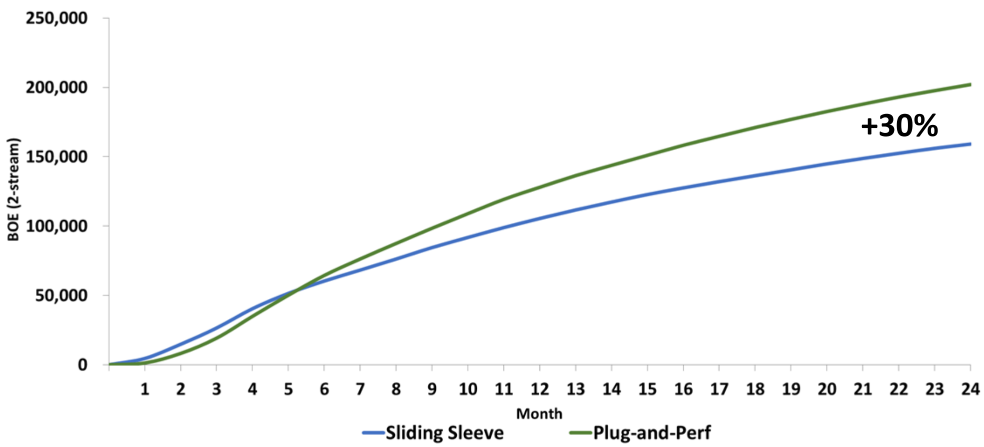


EUR (Mboe)	IRR[2]	Pre-Tax PV10 ($ millions)	Payout (Years)
500	34%	$2.9	2.0
600	47%	$4.2	1.8
700	54%	$5.6	1.7

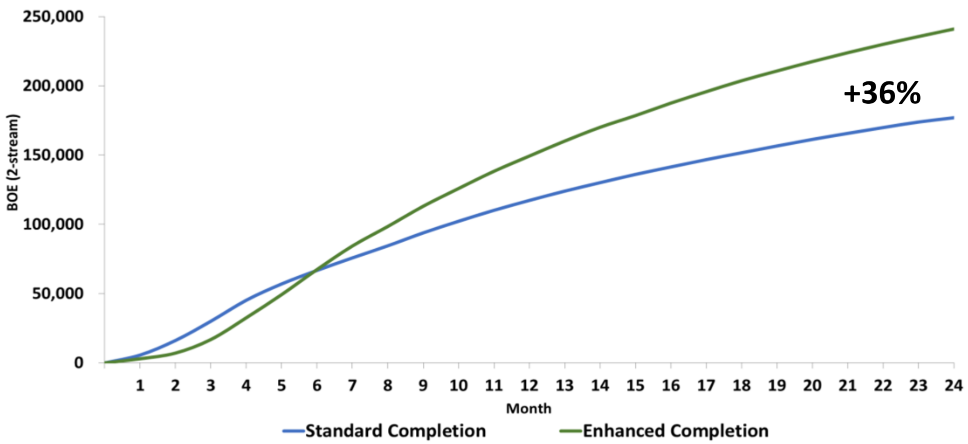
[1] Calculated for an XRL well with a ~9,500' lateral, 55-stage plug-and-perf, $4.75 mm well cost, $4.00/bbl WTI differential for 1st two years & $7.00/bbl thereafter
[2] Based on $55/bbl flat WTI, a $250k decrease in well costs improves IRR by ~5%

Evolution of XRL Completion Design

Plug and Perf



Enhanced Completion Design



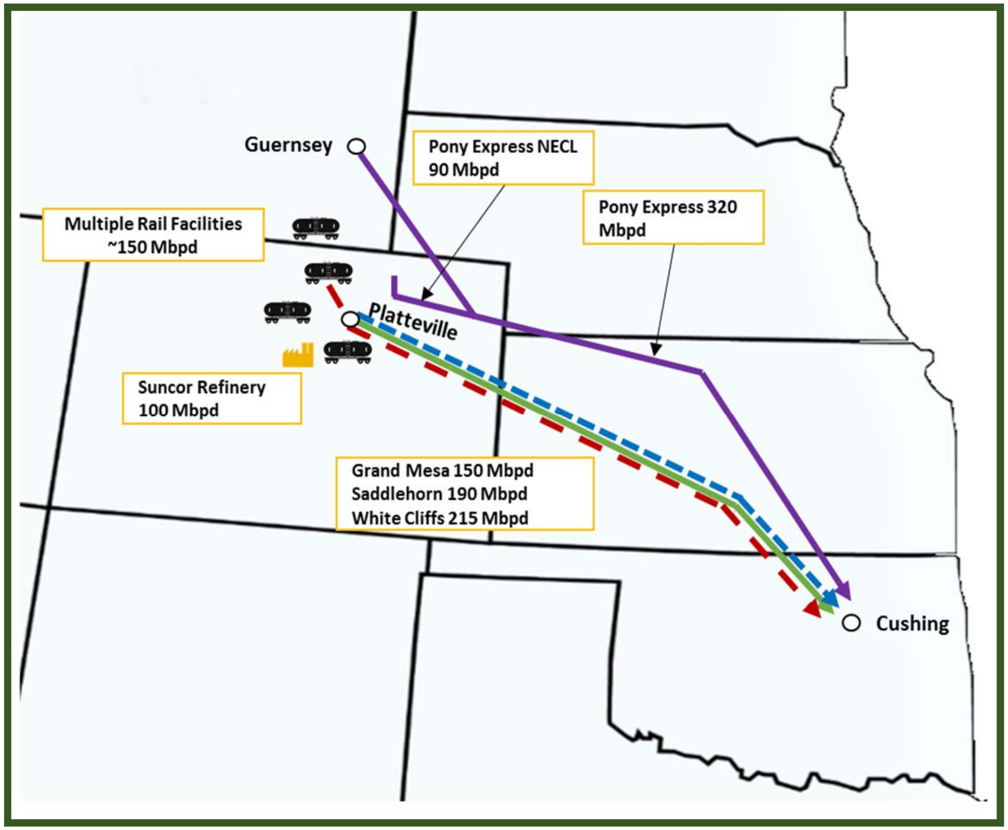
2017 Completion Objectives

- **Increase proppant to 1,500 lbs per lateral foot from 1,350 lbs per lateral foot**
- **Reduce frac stage spacing from 175’ (55-stages) to 120’ (80-stages)**
- **Adjust fluid design to allow more sand to be placed in wellbore**

DJ Basin Infrastructure

DJ Basin Take-Away Snapshot

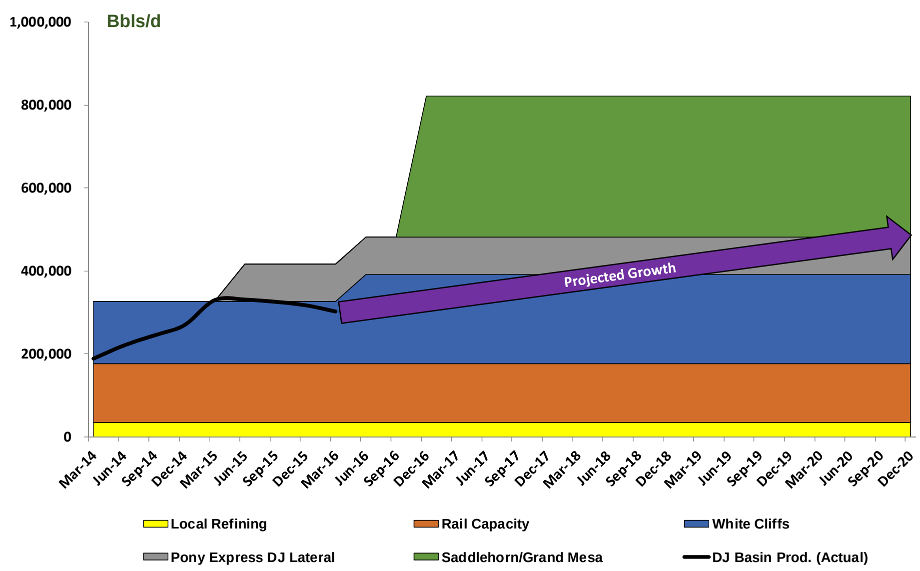
- **DJ Basin take-away capacity remains significantly above current production levels**
- **Pipeline infrastructure provides multiple outlets to Cushing marketplace**
- **Third-party oil marketers continue to discount pipeline tariffs in an effort to fill contractual capacity**



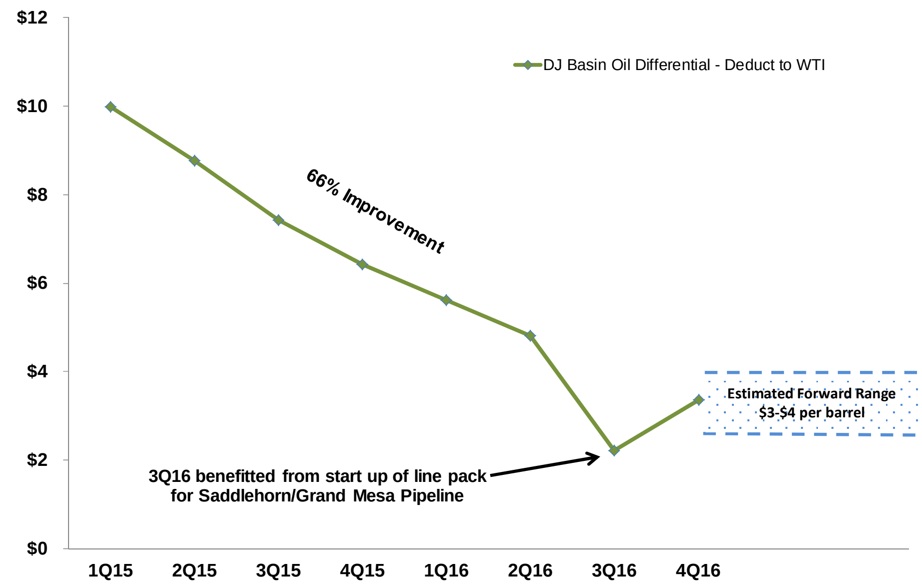
Improving DJ Basin Infrastructure

- **Weld County to Cushing pipeline capacity totals ~650 Mbbls/d**
- **Local refineries and rail provide additional outlets**
- **BBG benefits from having no firm marketing commitments and favorable API gravity crude**
- **Oil price differential expected to average ~$3-$4 per barrel below WTI**
  - 4Q16 differential averaged $3.67 per barrel

DJ Basin Takeaway Capacity vs. Production



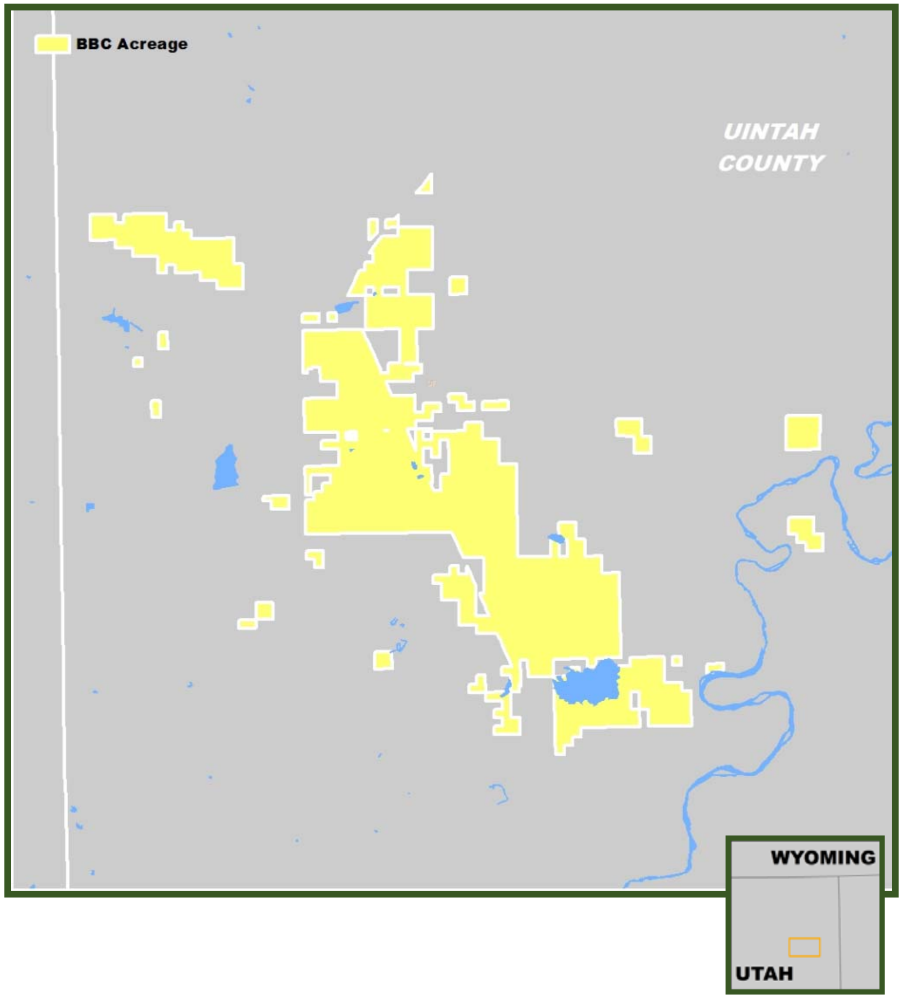
DJ Basin Oil Price Differential (operated)



Source: COGCC and company estimates

East Bluebell ~24,000 net acres

- **Well development targeting Lower Green River formation**
- **High oil cut (~90%) provides strong margins and steady cash flow**
- **Changing market dynamics allows for renegotiation of marketing contract leading to significant improvement in differentials**
  - Differential expected to average ~$2 per barrel beginning in the second quarter 2017
  - 2016 differential averaged $7.75 per barrel
- **Recompletion program expected to begin in the second quarter 2017**
- **4Q16 production of 2,000 Boe/d**



Summary

- Core acreage position located within a top-tier basin
- Solid financial position with cash, attractive hedges and undrawn credit facility
- Execution of items within our control to generate operational efficiencies that reduce cost structure
- Financial capacity to fund growth activity
- Positioned to deliver competitive growth profile

APPENDIX

4Q16 Highlights

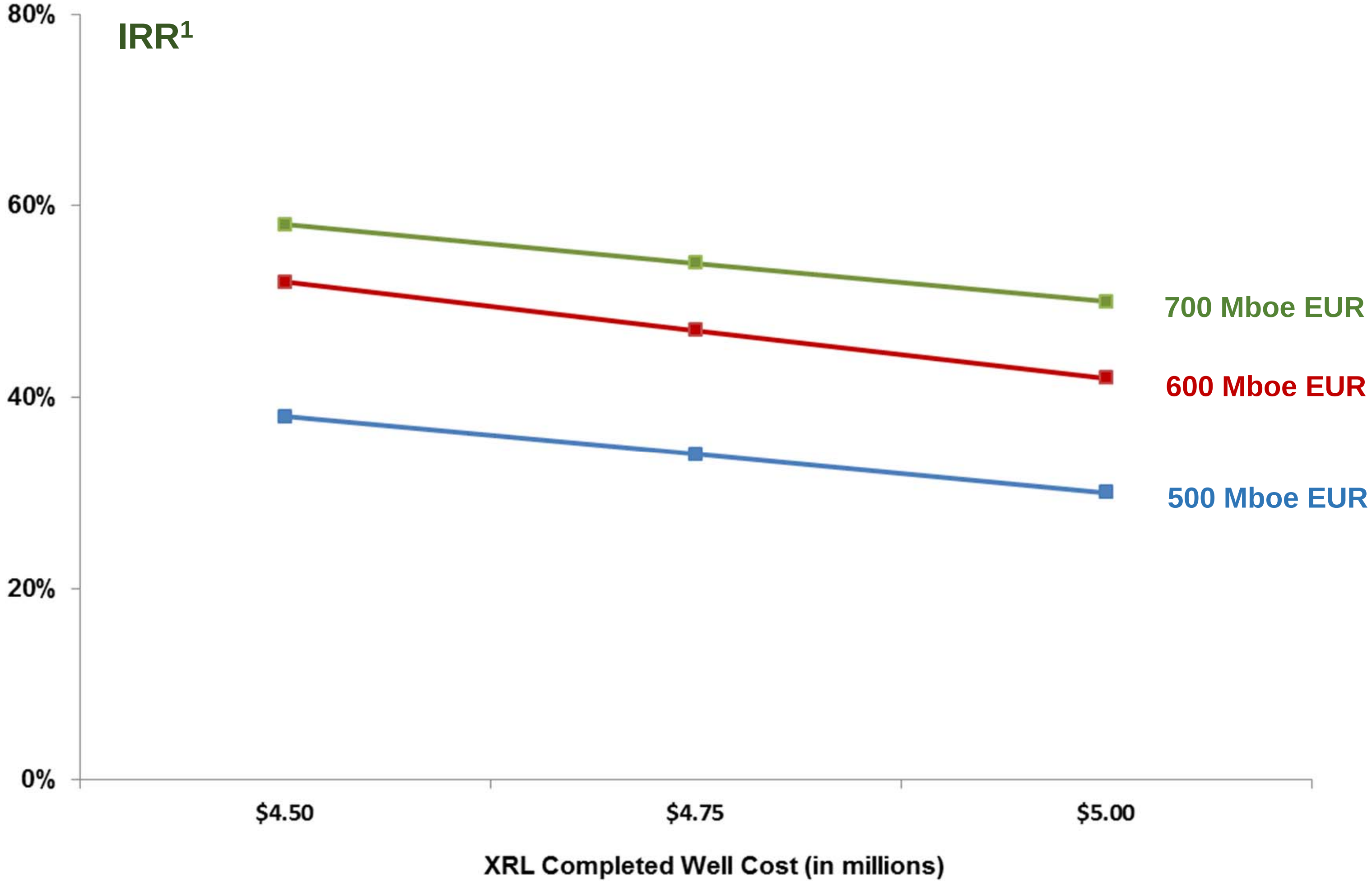
- **Production of 1.6 MMBoe, in line with expectations**
  - 62% oil, 20% natural gas and 18% NGLs
  - Fewer wells with initial flush oil production skewing gas proportion higher
- **DJ Basin oil price differential narrowed to a basin leading $3.67 per barrel**
  - 48% improvement from fourth quarter of 2015
  - Benefit from having no long-term oil marketing agreements
- **Delivered continued cost improvement as LOE averaged $3.73 per Boe**
  - DJ Basin LOE of $2.96 per Boe, represents 9% year-over-year improvement
- **Opportunistically bolstered liquidity through public equity offering**
  - Received net proceeds of $110 million
  - Additional liquidity provides operational and financial flexibility
- **Exited 2016 with cash of $276 million; Reduced net debt to $442 million**
- **Recently completed bolt-on DJ Basin transaction for ~13,800 net acres**
  - Adds ~80 operated XRL locations and additional ownership in ~20 XRL locations

2016 Highlights

- **Production of 6.1 MMBoe was at mid-point of guidance range**
- **Net Cash from Operations of ~$122 million**
  - Discretionary Cash Flow of ~$126 million[1]
- **Capital expenditures of $98 million were 22% below discretionary cash flow**
- **Delivered cost improvement as LOE averaged $4.58 per Boe, represents 29% improvement**
  - DJ Basin LOE of $3.41 per Boe, represents 27% improvement
- **DJ Basin oil price differential narrowed to a basin leading $3.45 per barrel, represents 58% improvement**
- **Financially well positioned with significant cash position, undrawn credit facility and solid hedge position**

[1] Discretionary cash flow is a non-GAAP measure, please reference the reconciliations to GAAP financial statements in the Appendix

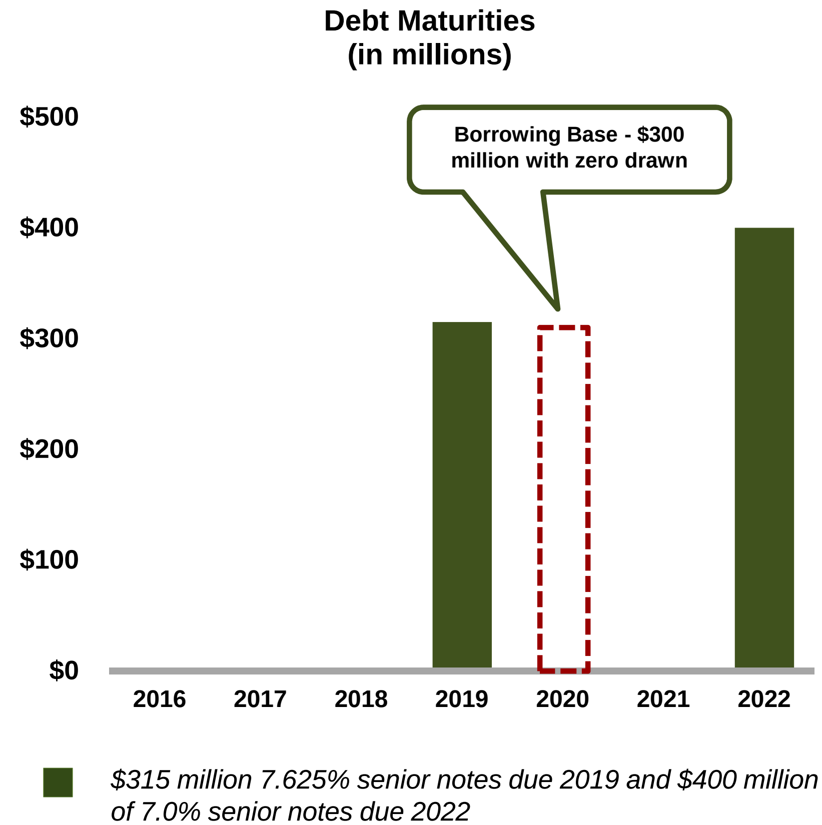
DJ Basin XRL Indicative Economics



[1] *Calculated for an XRL well with a ~9,500' lateral, 55-stage plug-and-perf, $55/bbl flat WTI, $4.00/bbl WTI differential for 1st two years & $7.00/bbl thereafter*

Long-term Debt Profile

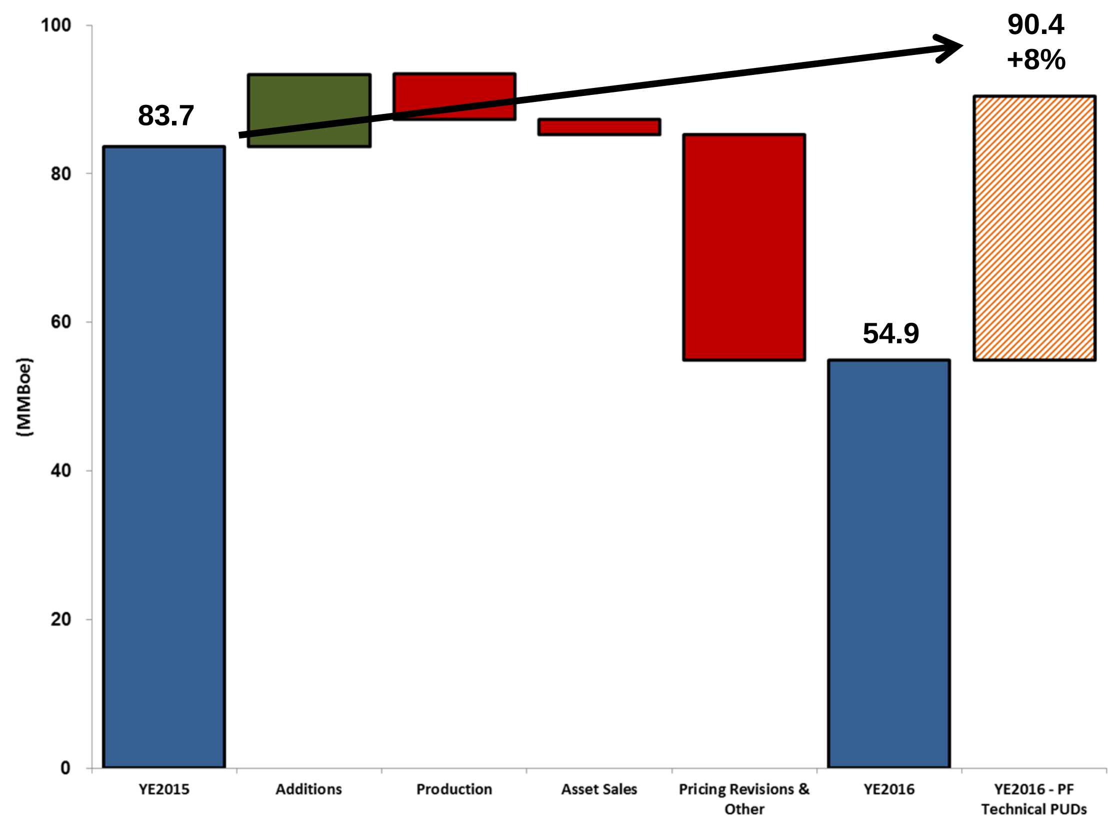
- **Borrowing base of $300 million with zero drawn**
  - Cash position of $276 million at December 31, 2016
  - No need to draw funds anticipated in 2017
- **Nearest debt maturity is not until 2019**
- **Net-debt/EBITDAX ratio of 2.4x at December 31, 2016**
- **Liquidity enhanced with net cash proceeds of $110 million equity offering completed in December 2016**
- **Bond trading prices are near par**



2016 Proved Reserves

- **Pro forma reserve growth of 8%, adjusted for technical reserves**
- **YE2016 proved reserves were lower due to commodity price-related and other revisions**
  - 66% proved developed
  - 57% crude
- **Conservative approach was taken for PUD reserves based on reduced activity level of 2016**

Proved Reserves Summary
YE 2015 – YE 2016



Oil and Natural Gas Hedge Summary

As of March 13, 2017

Swaps				
Period	**Oil**		**Natural Gas**	
	Volume (Bbls/d)	WTI Price ($/Bbl)	Volume (MMBtu/d)	NWPL Price ($MMBtu)
1Q17	6,500	$ 58.20	10,000	$ 2.96
2Q17	6,625	$ 58.10	10,000	$ 2.96
3Q17	7,125	$ 58.77	10,000	$ 2.96
4Q17	7,125	$ 58.77	10,000	$ 2.96
1Q18	3,750	$ 54.97		
2Q18	3,750	$ 54.97		
3Q18	1,500	$ 55.06		
4Q18	1,500	$ 55.06		

Core Development Land Summary

As of December 31, 2016

Area	Gross Acreage	Net Acreage
Uinta Basin – Uinta Oil Program		
East Bluebell	35,454	24,248
DJ Basin		
Northeast Wattenberg[1]	68,996	48,447
Chalk Bluffs	18,973	5,705
Other	7,550	3,303
Total DJ Basin Program	**95,519**	**57,455**

[1] Includes to be earned acreage of 2,553 gross and 1,578 net acres

4Q16 and Full Year 2016 Financial Results

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2016	2015	2016	2015
Net cash provided by operating activities ($ millions)	$5.5	$27.8	$121.7	$193.7
Discretionary cash flow ($ millions)[1]	$32.4	$53.3	$126.1	$206.3
Net income (loss) ($ millions)	($49.3)	($21.1)	($170.4)	($487.8)
Per share, basic	($0.79)	($0.45)	($3.08)	($10.10)
Per share, dilutive	($0.79)	($0.45)	($3.08)	($10.10)
Adjusted net income (loss) ($ millions)[1]	($11.2)	$3.4	($37.8)	($9.4)
Per share, basic	($0.18)	$0.07	($0.68)	($0.20)
Per share, dilutive	($0.18)	$0.07	($0.68)	($0.20)
Weighted average shares outstanding, basic (in thousands)	62,241	48,373	55,384	48,303
Weighted average shares outstanding, diluted (in thousands)	62,241	48,373	55,384	48,303
EBITDAX ($ millions)[1]	$45.8	$68.3	$182.4	$266.2

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2016	2015	2016	2015
Production sales volumes (Mboe)	1,550	1,685	6,090	6,593
Daily production sales volumes (Boe/d)	16,848	18,315	16,639	18,063
Production sales volumes, excluding asset sales (Mboe)	1,548	1,430	5,832	5,274
Production sales volumes, excluding asset sales (Boe/d)	16,830	15,543	15,977	14,410
Oil price differential (per barrel)	$4.53	$6.61	$4.49	$8.73
DJ Basin oil price differential (per barrel	$3.67	$6.42	$3.45	$8.21
Average Costs (per Boe):				
Lease operating expenses	$3.73	$4.70	$4.58	$6.48
Gathering, transportation and processing	$0.32	$0.55	$0.39	$0.53
Production tax	$2.32	$1.29	$1.75	$1.85
Depreciation, depletion and amortization	$29.76	$27.06	$28.18	$31.14
General and administrative expense	$6.86	$8.82	$6.92	$8.17

[1] Discretionary cash flow, adjusted net income (loss) and EBITDAX are non-GAAP (Generally Accepted Accounting Principles) measures. Please reference the reconciliations to GAAP financial statements on the following pages

Non-GAAP Reconciliation (Unaudited)

Discretionary Cash Flow Reconciliation

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2016	2015	2016	2015
	(in thousands)			
Net Cash Provided by (Used in) Operating Activities	$5,529	$27,777	$121,736	$193,678
Adjustments to reconcile to discretionary cash flow:				
Exploration expense	19	8	83	153
Changes in working capital	26,875	25,490	4,262	12,504
Discretionary Cash Flow	32,423	53,275	126,081	206,335

Adjusted Net Income (Loss) Reconciliation

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2016	2015	2016	2015
	(in thousands, except per share amounts)			
Net Income (Loss)	($49,277)	($21,145)	($170,378)	($487,771)
Provision for (Benefit from) income taxes	—	—	—	(177,085)
Income (Loss) before Income Taxes	(49,277)	(21,145)	(170,378)	(664,856)
Adjustments to Net Income (Loss):				
Unrealized derivative (gain) loss	30,643	22,585	116,318	75,505
Impairment expense	—	72	183	572,438
(Gain) loss on sale of properties	(128)	2,504	1,078	1,745
(Gain) loss on extinguishment of debt	—	—	(8,726)	(1,749)
One-time items:				
CO2 unused commitment	—	1,429	—	1,429
West Tavaputs NGL processing true-up	—	(268)	—	(1,273)
Expenses relating to amending credit facility	—	—	—	1,617
(Income) expense related to properties sold	576	—	576	—
Adjusted Income (Loss) before Income Taxes	(18,186)	5,177	(60,949)	(15,144)
Adjusted (provision for) benefit from income taxes (1)	7,003	(1,804)	23,167	5,714
Adjusted Net Income (Loss)	($11,183)	$3,373	($37,782)	($9,430)
Per share, diluted	($0.18)	$0.07	($0.68)	($0.20)

[1] Adjusted (provision for) benefit from income taxes is calculated using the Company's current effective tax rate prior to applying the valuation allowance against deferred tax assets

Non-GAAP Reconciliation (Unaudited)

EBITDAX Reconciliation

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2016	**2015**	**2016**	**2015**
		(in thousands)		
Net Income (Loss)	($49,277)	($21,145)	($170,378)	($487,771)
Adjustments to reconcile to EBITDAX:				
Depreciation, depletion and amortization	46,150	45,609	171,641	205,275
Impairment, dry hole and abandonment expense	2,483	314	4,249	575,310
Exploration expense	19	8	83	153
Unrealized derivative (gain) loss	30,643	22,585	116,318	75,505
Incentive compensation and other non-cash charges	1,774	2,759	8,982	10,040
(Gain) loss on sale of properties	(128)	2,504	1,078	1,745
(Gain) loss on extinguishment of debt	—	—	(8,726)	(1,749)
Interest and other income	(69)	(46)	(235)	(565)
Interest expense	14,213	15,731	59,373	65,305
Provision for (benefit from) income taxes	—	—	—	(177,085)
EBITDAX	$45,808	$68,319	$182,385	$266,163

Discretionary cash flow and adjusted net income (loss) are non-GAAP measures. These measures are presented because management believes that they provide useful additional information to investors for analysis of the Company's ability to internally generate funds for exploration, development and acquisitions as well as adjusting net income (loss) for certain items to allow for a more consistent comparison from period to period. In addition, the Company believes that these measures are widely used by professional research analysts and others in the valuation, comparison and investment recommendations of companies in the oil and gas exploration and production industry, and that many investors use the published research of industry research analysts in making investment decisions.

These measures should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, profitability, cash flow or liquidity measures prepared in accordance with GAAP. The definition of these measures may vary among companies, and, therefore, the amounts presented may not be comparable to similarly titled measures of other companies.

Forward-Looking & Other Cautionary Statements

DISCLOSURE STATEMENTS

FORWARD-LOOKING STATEMENTS: This presentation (which includes oral statements made in connection with this presentation) contains 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. All written or oral statements, other than historical financial information, may be deemed to be forward-looking statements. Words such as expects, forecast, guidance, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements; however, these are not the exclusive means of identifying forward-looking statements. In particular, the Company is providing 2017 and 2018 operating guidance, which contains projections for certain 2017 and 2018 operational and financial metrics. Additional forward-looking statements in this presentation relate to, among other things, future capital expenditures, projects and opportunities.

These and other forward-looking statements in this presentation are based on management's judgment as of the date of this presentation and are subject to numerous risks and uncertainties. Actual results may vary significantly from those indicated in the forward-looking statements due to, among other things, oil, NGL and natural gas price volatility, including regional price differentials; changes in operational and capital plans; costs, availability and timing of build-out of third party facilities for gathering, processing, refining and transportation; delays or other impediments to drilling and completing wells arising from political or judicial developments at the local, state or federal level, including voter initiatives related to hydraulic fracturing; development drilling and testing results; the potential for production decline rates to be greater than expected; regulatory delays, including seasonal or other wildlife restrictions on federal lands; exploration risks such as drilling unsuccessful wells; higher than expected costs and expenses, including the availability and cost of services and material; and our potential inability to achieve expected cost savings; unexpected future capital expenditures; economic and competitive conditions; debt and equity market conditions, including the availability and costs of financing to fund the Company's operations; the ability to obtain industry partners to jointly explore certain prospects, and the willingness and ability of those partners to meet capital obligations when requested; declines in the values of our oil and gas properties resulting in impairments; changes in estimates of proved reserves; compliance with environmental and other regulations; derivative and hedging activities; risks associated with operating in one major geographic area; the success of the Company's risk management activities; title to properties; litigation; environmental liabilities and other factors discussed in the Company's reports filed with the Securities and Exchange Commission ("SEC").

Please refer to the Company's Annual Report on Form 10-K for the year ended December 31, 2016 filed with the SEC, specifically Item 1A, Risk Factors, and other filings including our Current Reports on Form 8-K and Quarterly Reports on Form 10-Q, for further discussion of risk factors that may affect the forward-looking statements. Those disclosures are incorporated by reference herein. The Company assumes no obligation to publicly revise or update any forward-looking statements based on future events or circumstances or otherwise, except as required by applicable law. All forward-looking statements are qualified in their entirety by this cautionary statement.

This presentation is neither an offer to sell nor a solicitation of an offer to buy any securities, nor shall there be any sale of any such securities in any state or jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such state or jurisdiction.

Forward-Looking & Other Cautionary Statements

Reserve Disclosure

The SEC generally permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company uses the terms "estimated ultimate recovery", "EUR" or other descriptions of potential reserves or volumes of reserves, as well as aggregated proved, probable and possible ("3P") reserves, which the SEC guidelines restrict from being included in filings with the SEC. The estimates conform to Society of Petroleum Evaluation Engineers (SPEE) methodology. They are not prepared or reviewed by third party engineers. EURs refer to the Company's internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or actual well completed in the area. Actual quantities that may be ultimately recovered from the Company's interests are unknown. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability and cost of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals and other factors, as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of ultimate recovery from reserves may change significantly as development of the Company's core assets provide additional data. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. The Company's EURs are provided in this presentation because management believes it is useful, additional information that is widely used by the investment community in the valuation, comparison and analysis of companies.

ADDITIONAL INFORMATION:

Rate of return estimates do not reflect lease acquisition costs or corporate general and administrative expenses.

Initial and test results from a well do not necessarily reflect the well's longer-term performance or the performance of other wells in the same area.

Bill Barrett Corporation

1099 Eighteenth Street, Suite 2300
Denver, CO 80202
303.293.9100
Website: www.billbarrettcorp.com

Investor Relations Contact:
Larry C. Busnardo
(303) 312-8514
lbusnardo@billbarrettcorp.com