



**BONANZA
CREEK**



Investor Presentation

Expanding the Runway

December 2012

Disclaimer

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 statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Bonanza Creek Energy, Inc. (the "Company") expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company's projected production rates; earnings; capital expenditure levels; capitalization and liquidity; timing and results of its drilling program; horizontal drilling and fracture stimulation operations; oil and gas prices; development, type curve and economic assumptions; hedging activities and use of derivative instruments; expansion of processing facilities; and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate under the circumstances.

Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include, but are not limited to economic conditions in the United States and globally; changes in domestic and global demand for oil and natural gas; changes in oil and natural gas prices; the Company's ability to acquire or discover additional reserves on economic terms; the Company's ability to economically develop its acreage and to achieve anticipated production levels, including in emerging shale plays; operational factors affecting the commencement or maintenance of producing wells; the timing of planned capital expenditures; weather and environmental conditions; the successful and economic use of horizontal drilling and fracture stimulation techniques; uncertainties in estimating proved reserves and forecasting production results; expiration of leased acreage and title deficiencies; the condition of credit and capital markets generally, as well as the Company's ability to obtain financing on acceptable terms; the availability and costs of gathering, processing and transportation; uncertainties regarding environmental regulations; litigation and other legal or regulatory developments affecting the Company's business, including regulation relating to fracture stimulation; and other important factors that could cause actual results to differ materially from those projected in this presentation and in the Company's filings with the SEC. For further detail on these and other risks and uncertainties, we refer you to the information under the headings "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and in comparable sections of our Quarterly Reports on Form 10-Q, filed with the SEC. All of the forward-looking statements made in this presentation are qualified by these cautionary statements and are made only as of the date hereof. The Company does not undertake, and specifically declines, any obligation to update any such statements or to publicly announce the results of any revisions to any such statements to reflect future events or developments.

In this presentation the terms "EUR" (estimated ultimate recovery) and "resource potential" are used to provide estimates. Resource potential in particular refers to the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques and have not been reviewed by independent engineers. Area wide unproven, unrisks resource potential has not been fully risked by Bonanza Creek's management. Actual quantities that may be ultimately recovered will likely differ substantially from these estimates. Estimates of resource potential may change significantly as development of our resource plays provide additional data. Factors affecting ultimate recovery include the scope of the Company's actual drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals, field spacing rules, actual recoveries of gas in place, length of horizontal laterals, actual drilling results, including geological and mechanical factors affecting recovery rates and other factors. These estimates are by their nature more speculative than estimates of proved reserves and, accordingly, are subject to substantially greater risk of not being actually realized by the Company. For a further discussion of the Company's proved reserves, as calculated under current SEC rules, we refer you to the Company's Annual Report on Form 10-K, referenced above, which is available on the Company's website at www.bonanzacrk.com and at the SEC's website at www.sec.gov.

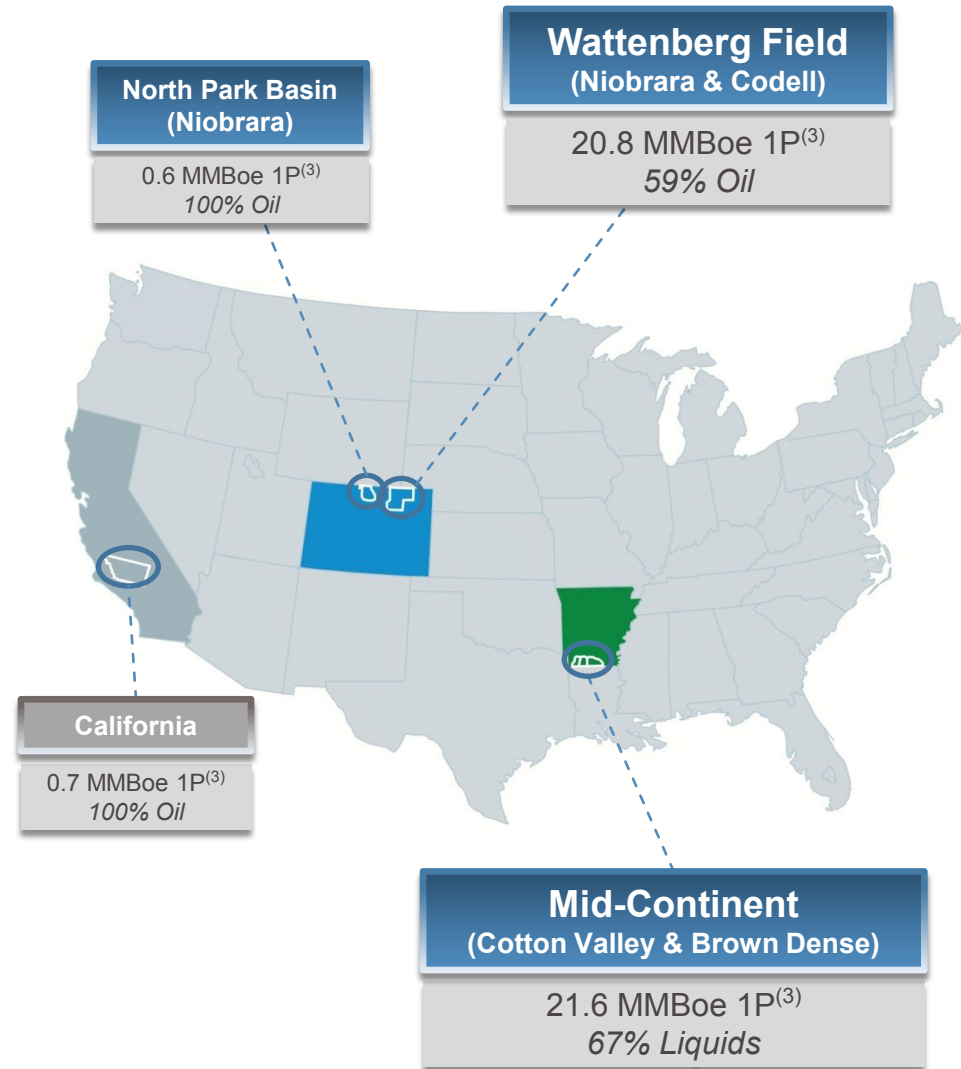
By attending or receiving this presentation you acknowledge that you will be solely responsible for your own assessment of the market and the market position of the Company and that you will conduct your own analysis and be solely responsible for forming your own view of the potential future performance of the Company's business.

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Bonanza Creek Overview

BCEI Market Cap⁽¹⁾: \$948 million
LISTED Share Price⁽¹⁾: \$23.70
NYSE Shares Outstanding⁽²⁾: ~40 million

- ◆ Rapidly growing
- ◆ Oil weighted
- ◆ Horizontal Niobrara flagship asset
- ◆ Arkansas low risk infill development



Third Quarter 2012 Highlights

3Q12 as compared to 3Q11

117% Increase in Production

◆ 9,545 Boe/d⁽¹⁾

527% Increase in Adj. Net Income⁽²⁾

◆ \$14.6 million (\$0.37/sh)

148% Increase in EBITDAX⁽²⁾

◆ \$39.6 million (\$1.00/sh)

86% of Revenue from Crude Oil

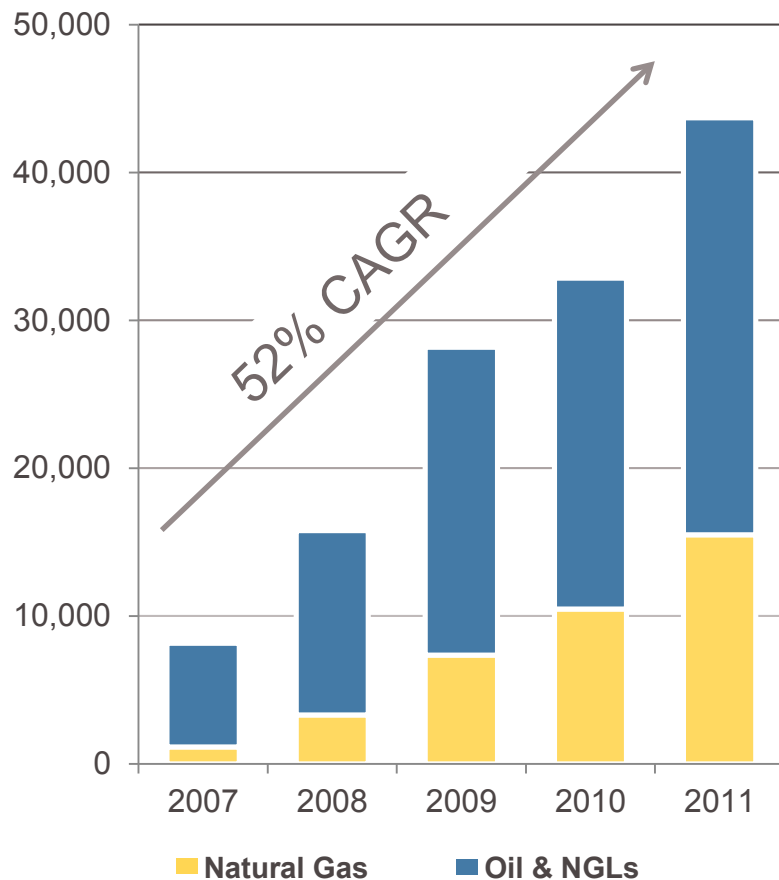
◆ 8% from natural gas

◆ 6% from natural gas liquids

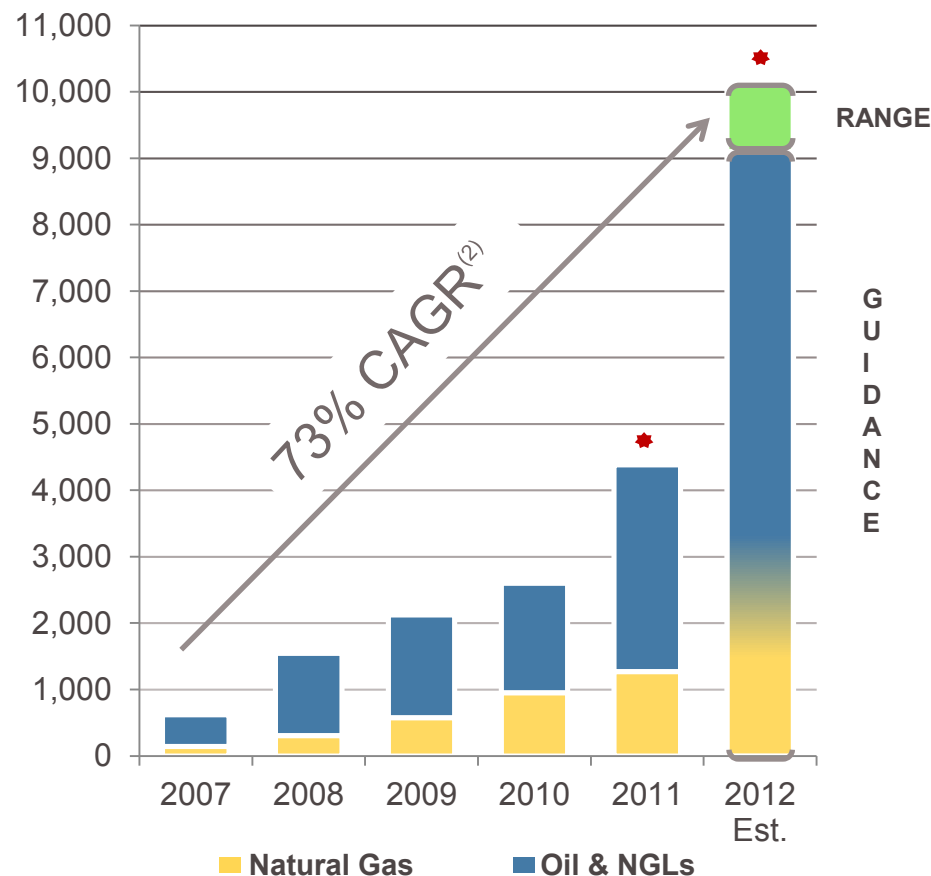


Track Record of Growth

Proved Reserves⁽¹⁾ (MBoe)



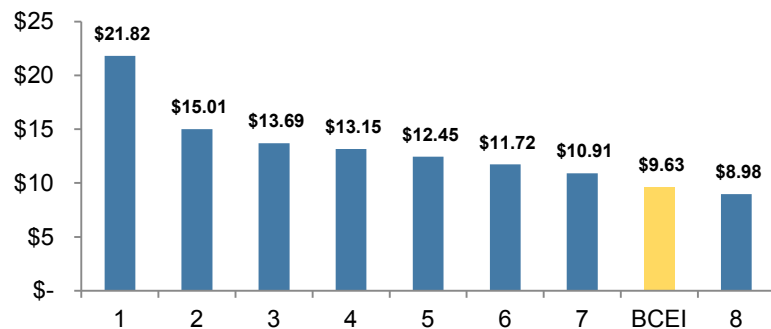
Production⁽¹⁾ (Boe/d)



* Significantly increased capital expenditures

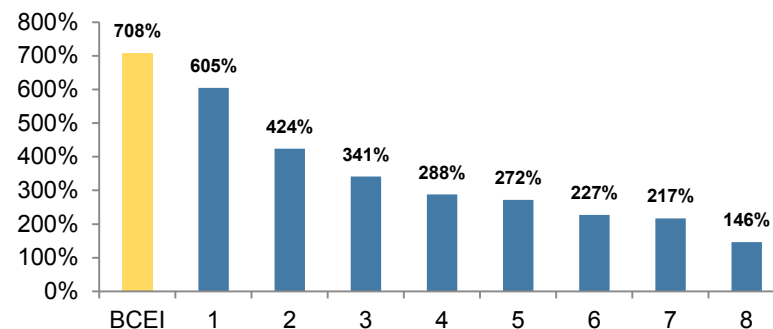
Leading Financial and Operating Performance vs. Peers

3-Year F&D Cost (\$/Boe)



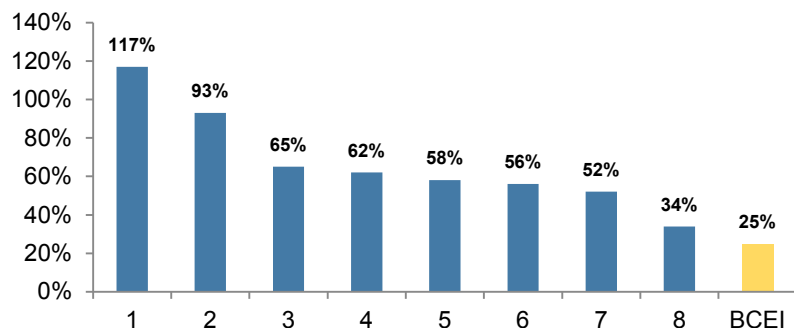
3-Year F&D calculated as costs incurred in oil and gas activities, excluding abandonment costs, divided by the sums of extensions, discoveries, revisions, and purchases of proved reserves over a three year period

3-Year Production Replacement



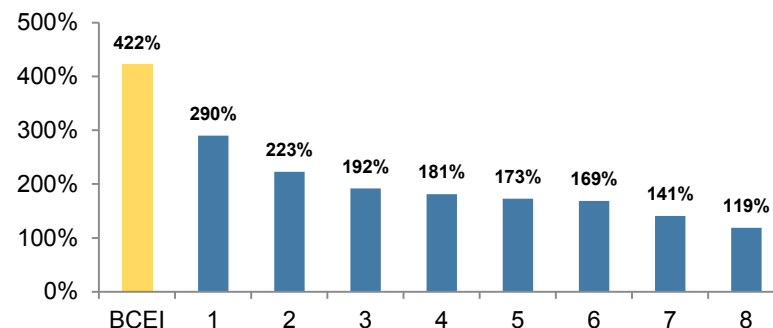
3-Year Production Replacement calculated as the percentage of production replaced through extensions, discoveries, revisions and purchases of proved reserves over a three-year period. The measurement period is 2009-2011

TTM Asset Intensity



Asset Intensity estimates the percent of operating cash flow required to reinvest to maintain reserves and production at current levels, and is calculated as (TTM production x 3-Year F&D costs) / TTM cash flow from operations

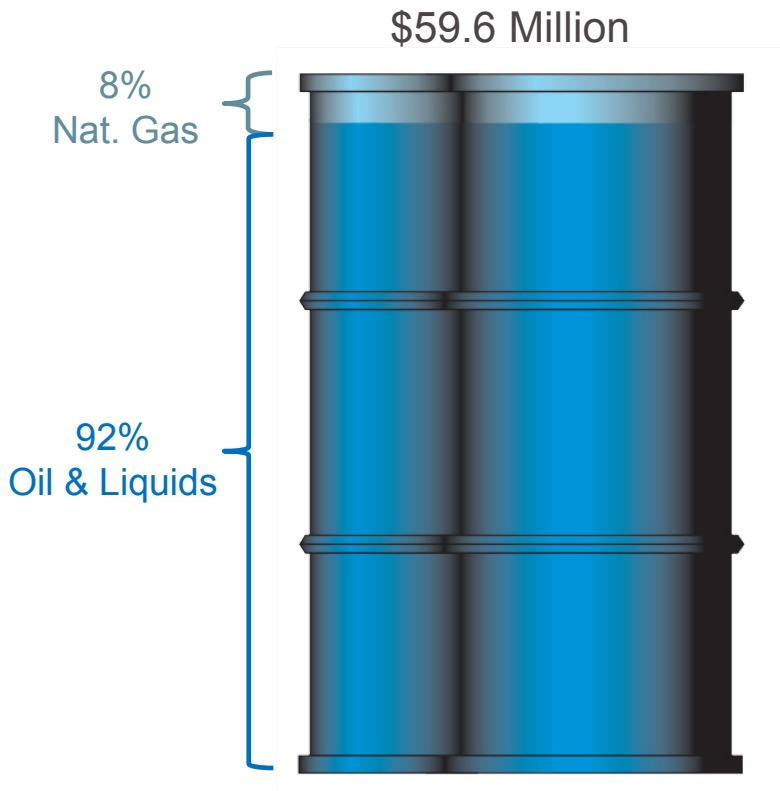
TTM Capital Efficiency



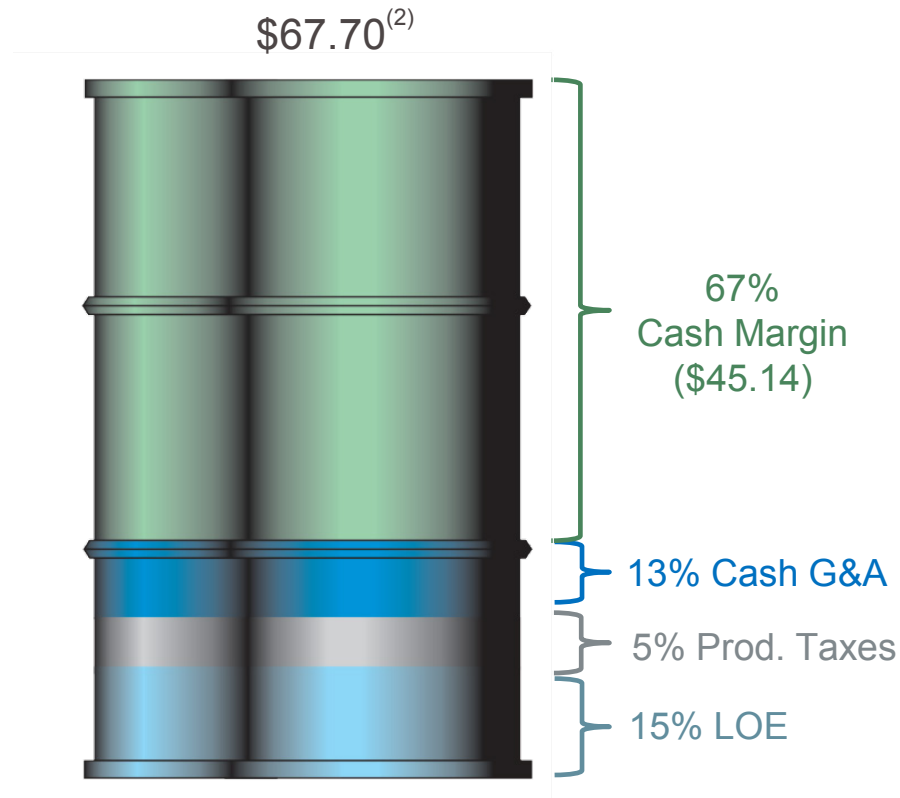
Capital Efficiency approximates cash flow generated for each investment dollar and is calculated as (trailing twelve month EBITDA / trailing twelve month production) / 3-Year F&D cost per Boe

Oil Weighted Assets Drive Strong Margins

3Q 2012 Revenue

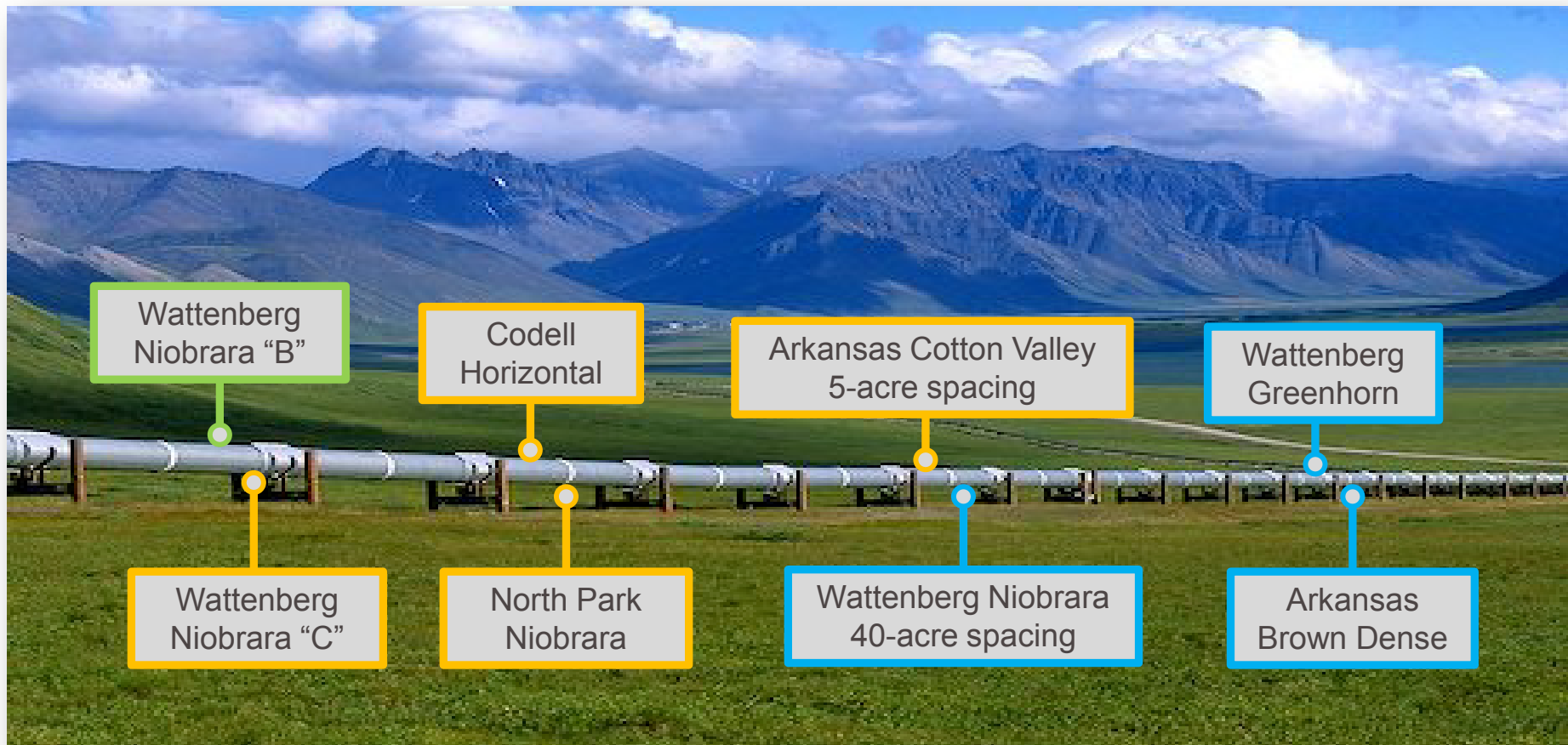


Unhedged Cash Margin / Boe⁽¹⁾



Organic Growth Pipeline

- ◆ 250 MMBoe of resource potential⁽¹⁾
- ◆ 8 primary opportunities in various stages of development and evaluation



— Full Development — Testing — Evaluating

First Half 2012 Results Drove Increased CapEx

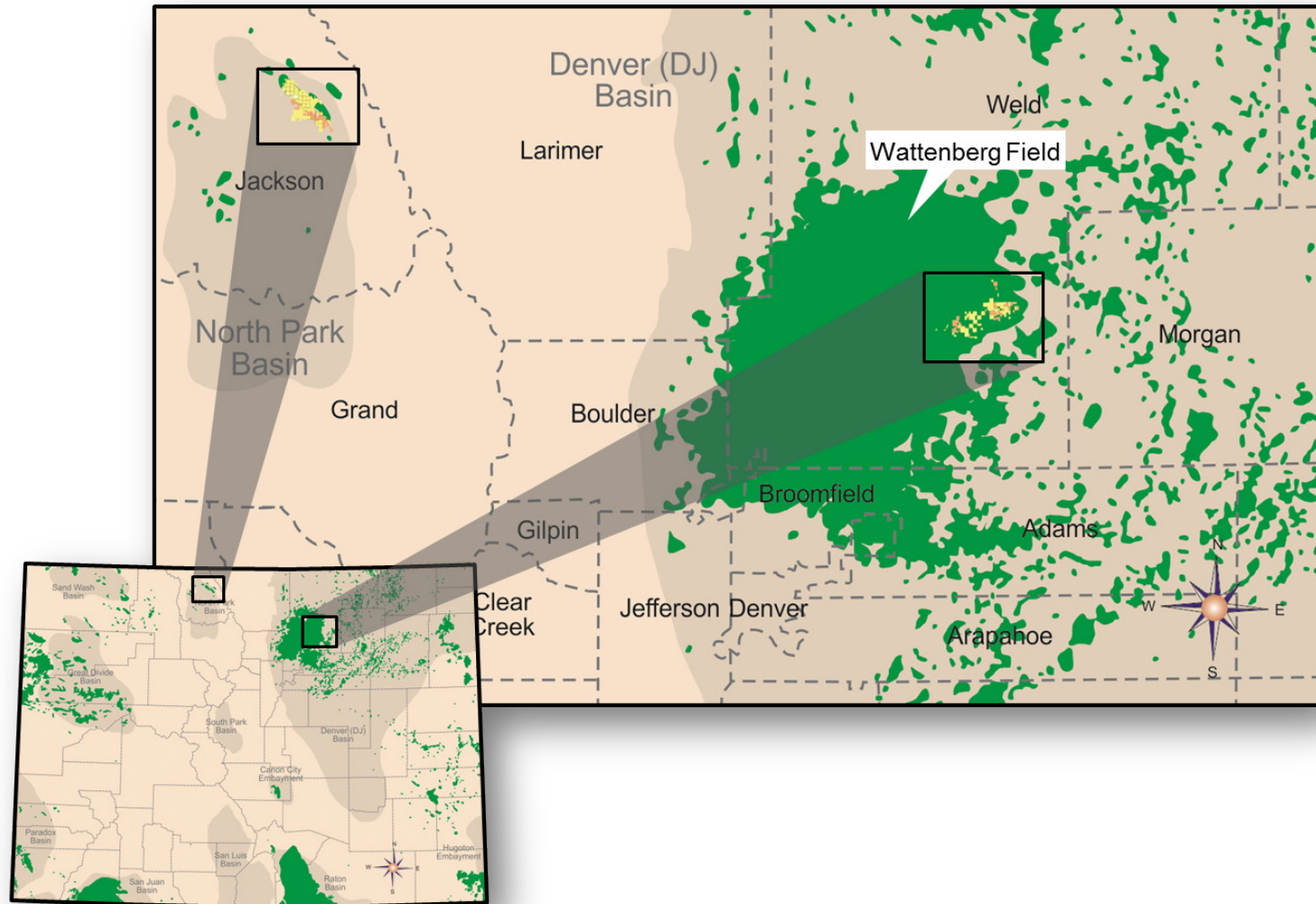
Original CapEx Budget: \$250MM

- Wattenberg Field: \$146 million
 - Horizontal: 24 wells
 - Vertical Niobrara/Codell: 92 wells
- Arkansas Upstream: \$56 million
 - Cotton Valley: 38 wells
- Arkansas Midstream: \$20 million
 - Expansion of gas processing facility
- Other: \$28 million
 - North Park Basin, Recompletions

Increased CapEx Budget: \$298MM

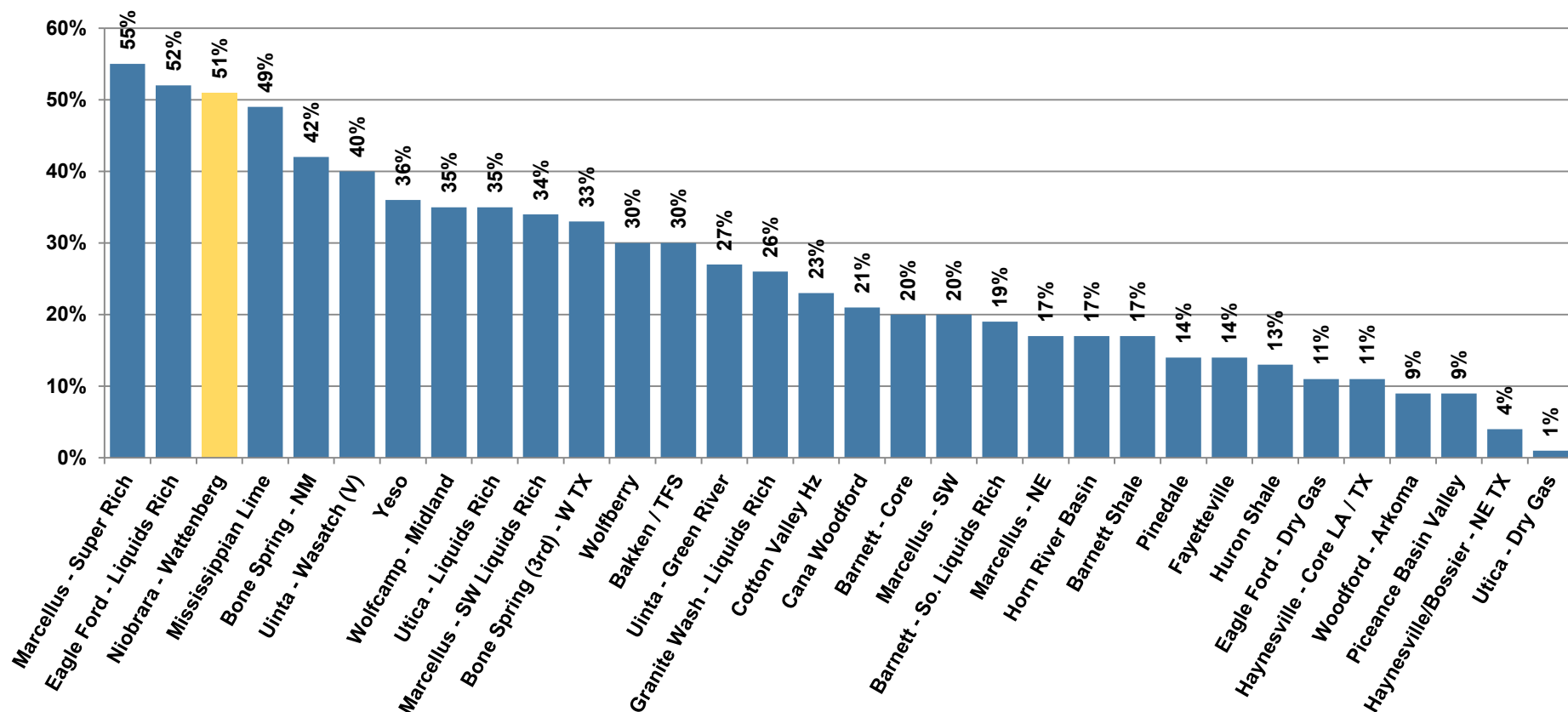
- Wattenberg Field: \$183 million
 - Horizontal: 36 wells⁽¹⁾ 
 - Vertical Niobrara/Codell: 72 wells 
- Arkansas Upstream: \$67 million
 - Cotton Valley: 38 wells
 - Downspacing pilot: 3 wells 
 - McKamie-Patton: 4 wells 
- Arkansas Midstream: \$20 million
 - Expansion of gas processing facility
- Other: \$28 million
 - North Park Basin, Recompletions

Rocky Mountain Operations



Colorado

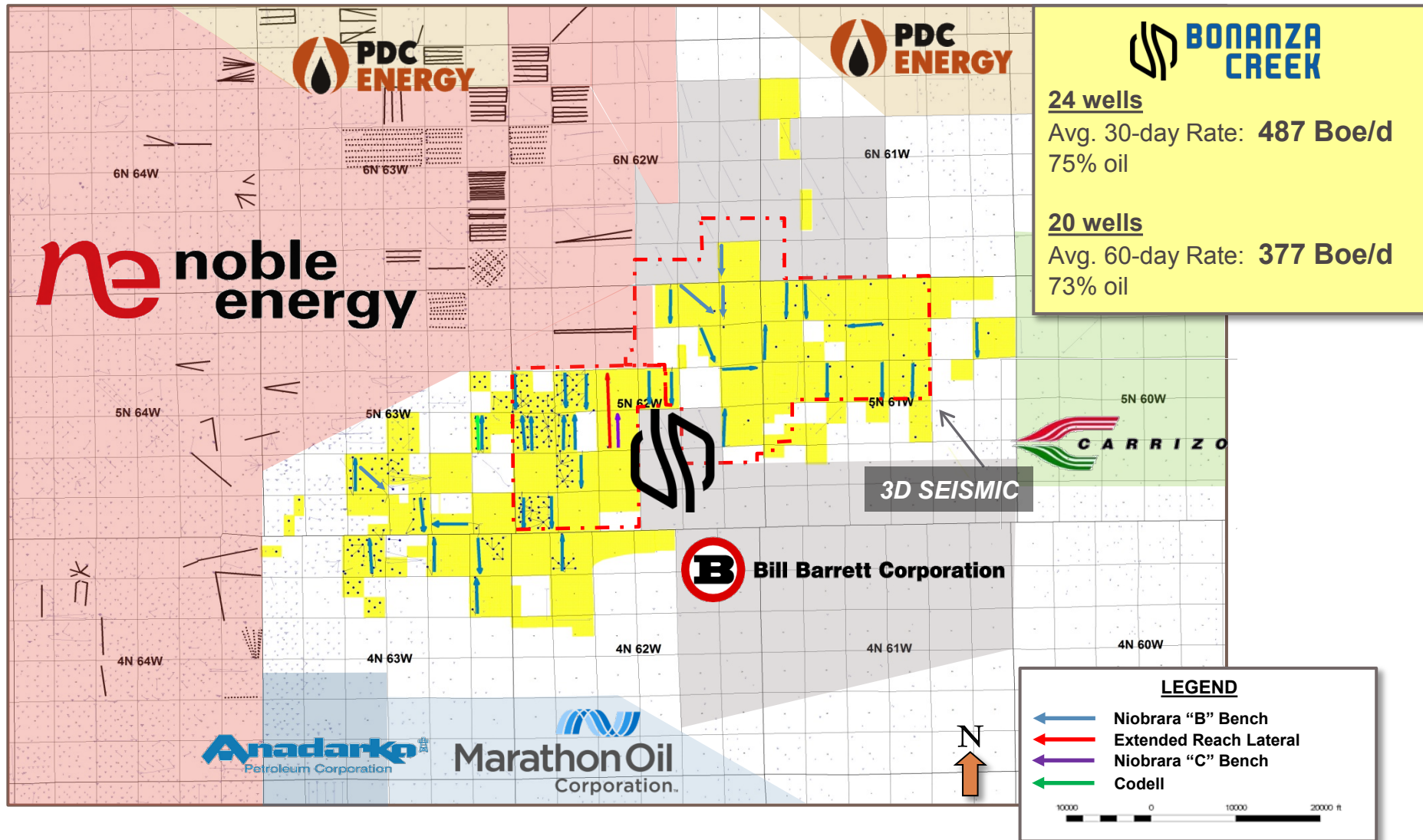
Basin IRR's – Wattenberg Niobrara at the Top



Futures Strip as of 9/28/2012

Year:	1	2	3	4	5	6	7	8+
WTI Oil:	\$93.26	\$93.71	\$91.78	\$89.35	\$87.74	\$86.87	\$86.87	\$86.87
NYMEX Gas:	\$3.33	\$3.85	\$4.18	\$4.37	\$4.55	\$4.74	\$4.74	\$4.74

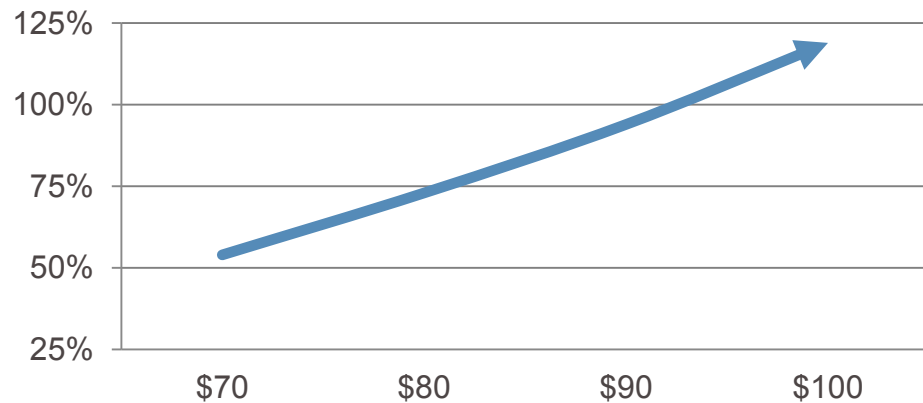
Wattenberg Field – Horizontal Niobrara



Wattenberg 80-acre Horizontal Niobrara Economics

EUR	312,000 Boe; 65% crude oil
Initial 30-day Rate	469 Boe/d
Cost per Well	\$4.2 MM
NPV-10 at \$80/BO	\$4.1 MM
NPV-10 at \$100/BO	\$6.1 MM
Engineered Locations	360 net ⁽¹⁾ 4,000 ft “B” Bench at 80-acre spacing

BTAX IRR % at \$/BO WTI⁽²⁾



Wattenberg Performance & Inventory Potential

1) Extended Reach Laterals

- ◆ ~9,000 foot lateral; ~40 stage frac
- ◆ NBL 3 well⁽¹⁾ average D&C cost: \$8.3 MM
- ◆ NBL 3 well average EUR: 750 MBoe
- ◆ Improves F&D costs from \$12.82/Boe to \$10.00/Boe over standard 4,000 foot laterals
- ◆ BCEI extended reach lateral planned for 4Q 2012

3) Niobrara “C” Bench Horizontal

- ◆ No evidence of “C” bench stimulation from “B” bench fracs
- ◆ “C” Bench present on all Wattenberg acreage
 - ◆ Expected economics similar to Niobrara “B” 4,000 ft. laterals
 - ◆ Potentially doubling 4,000 ft. lateral inventory in the Niobrara
- ◆ BCEI Niobrara “C” Bench well planned for 4Q 2012

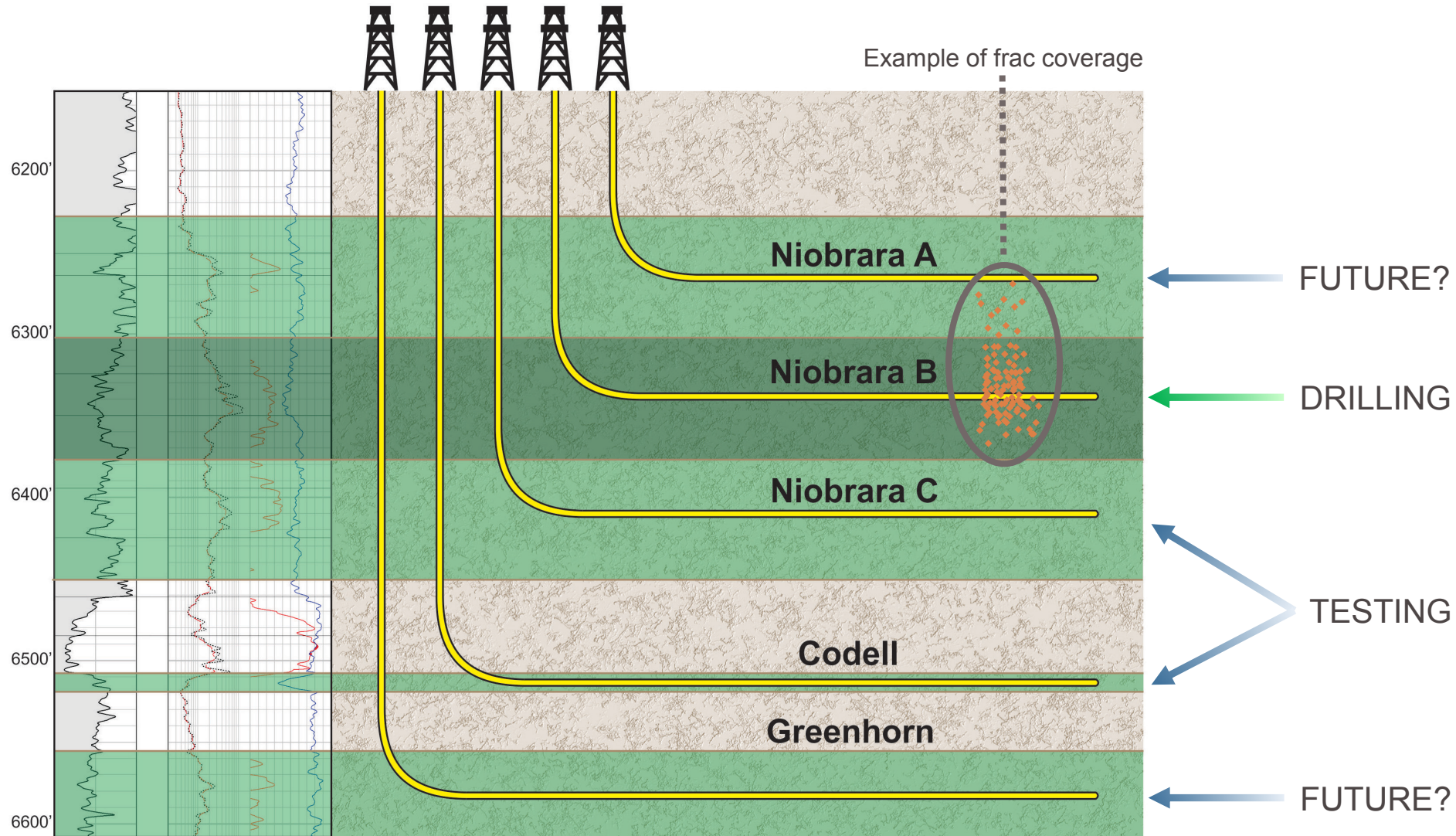
2) Codell Horizontal Development

- ◆ Industry Results⁽²⁾ (30-day rate)
 - ◆ (APC) PSC 12C-13HZ: 486 Boe/d
 - ◆ (APC) PSC 13C-13HZ: 441 Boe/d
- ◆ Codell prospective on ~15,000 net acres
 - ◆ Expected economics similar to Niobrara “B” 4,000 ft. laterals
- ◆ BCEI completed its first Codell well in October 2012

4) Downspacing to 40-acres

- ◆ Offset operators currently testing 40-acre spacing
- ◆ Horizontal locations within vertical well development

Wattenberg Inventory Targets

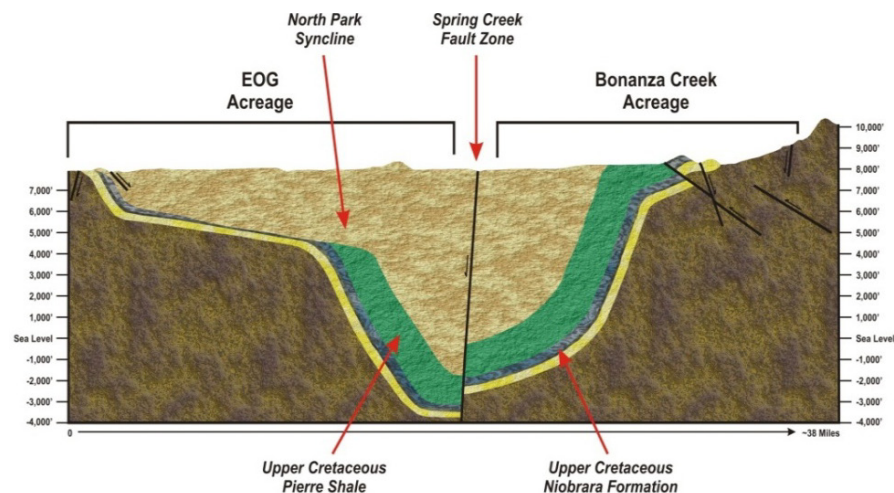
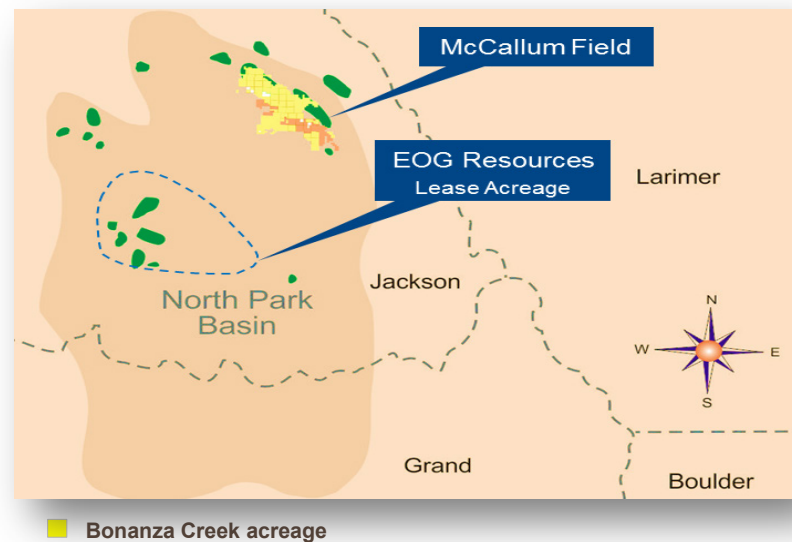
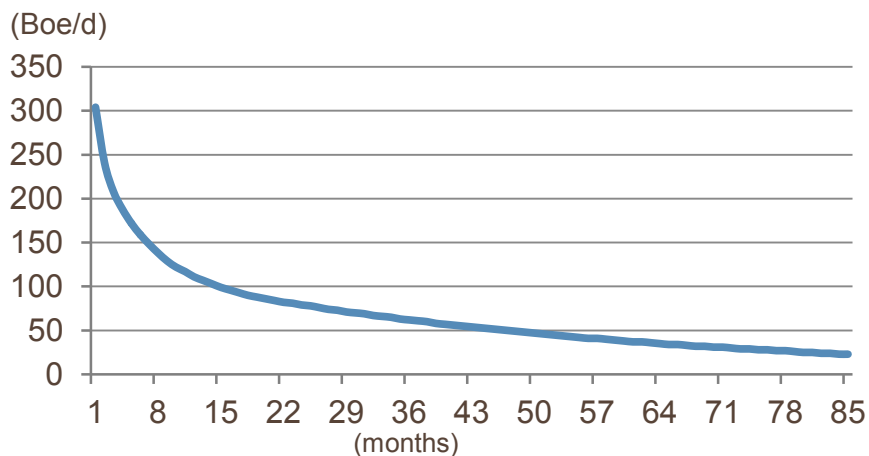


North Park Basin Niobrara⁽¹⁾

EUR	211,000 Boe
Initial 30-day Rate	304 Boe/d
% Oil	90%
Cost per Well	\$5.1 MM
NPV-10 at \$80/BO	\$2.1 MM
NPV-10 at \$100/BO	\$3.9 MM

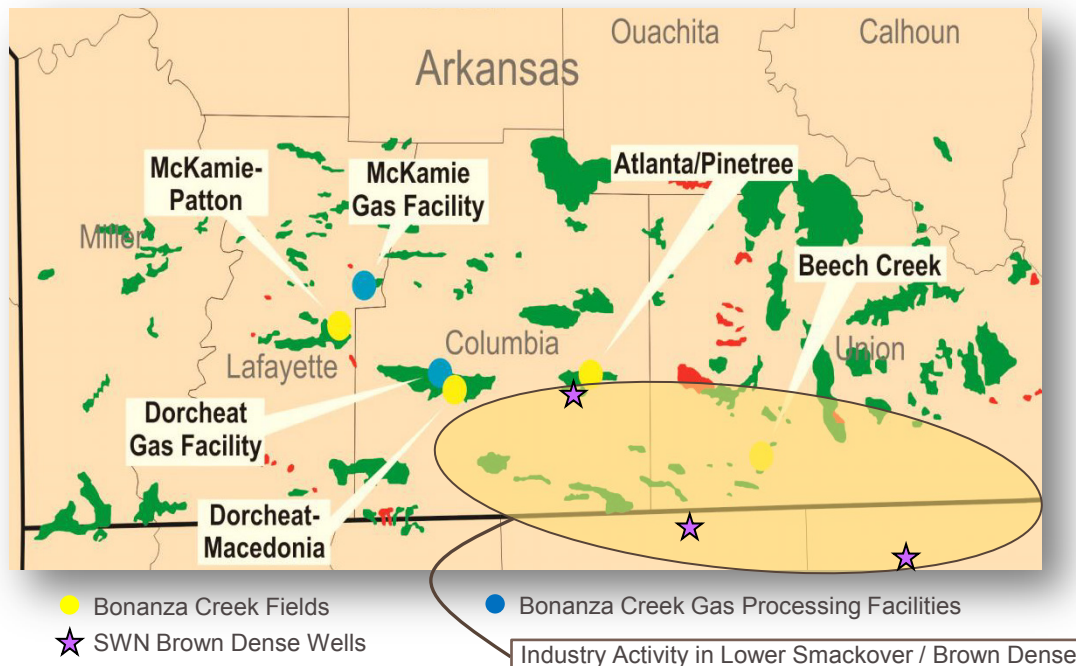
- 2014-2015 development opportunity – EVALUATING
- No natural gas takeaway capacity

Type Curve⁽²⁾



Mid-Continent Operations (Arkansas)

- Primary Target: Cotton Valley: 4,000 – 7,000 feet
- Potential inventory upside catalysts:
 - Dorcheat-Macedonia 5-acre infill testing
 - McKamie-Patton
- Gas facilities expanding to 40 MMcf/d capacity in 1Q 2013



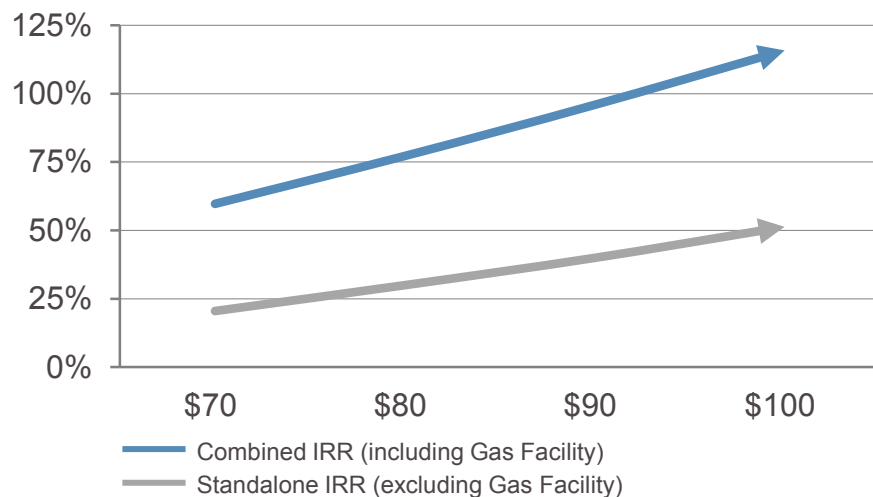
ERA	SYSTEM	SERIES	GROUP	FORMATION			
CENOZOIC		EOCENE	Claiborne				
		PALEOCENE	Wilcox				
	TERTIARY		Midway				
MESOZOIC	CRETACEOUS	GULFIAN (Upper Cretaceous)	Navarro				
			Taylor				
			Austin	Austin Chalk			
			Eagle Ford	Eagle Ford Shale			
			Woodbine	Woodbine			
		COMMANCHEAN (Lower Cretaceous)	Washita		Maness Shale		
					Buda		
					Del Rio Shale		
					Georgetown		
				Kiamichi			
	Fredericksburg		Goodland Lime				
		Paluxy Walnut					
	TRINITY	Glen Rose		Upper Glen Rose			
				Massive Anhydrite			
				Rodessa			
				Bexar			
				James			
				Pine Island			
				Pettet			
				Sligo			
				Travis Peak			
				Hosston			
			JURASSIC	UPPER JURASSIC	Cotton Valley	Cotton V. Sa.	Schuler
							Bossier
					Louark		Haynesville
						Buckner	
						Smackover	
	Norphlet						
MIDDLE JUR.	Louann			Louann Salt			
				Werner			
TRIASSIC (?)				Eagle Mills			
PALEOZOIC							

● Bonanza Creek Productive Formations

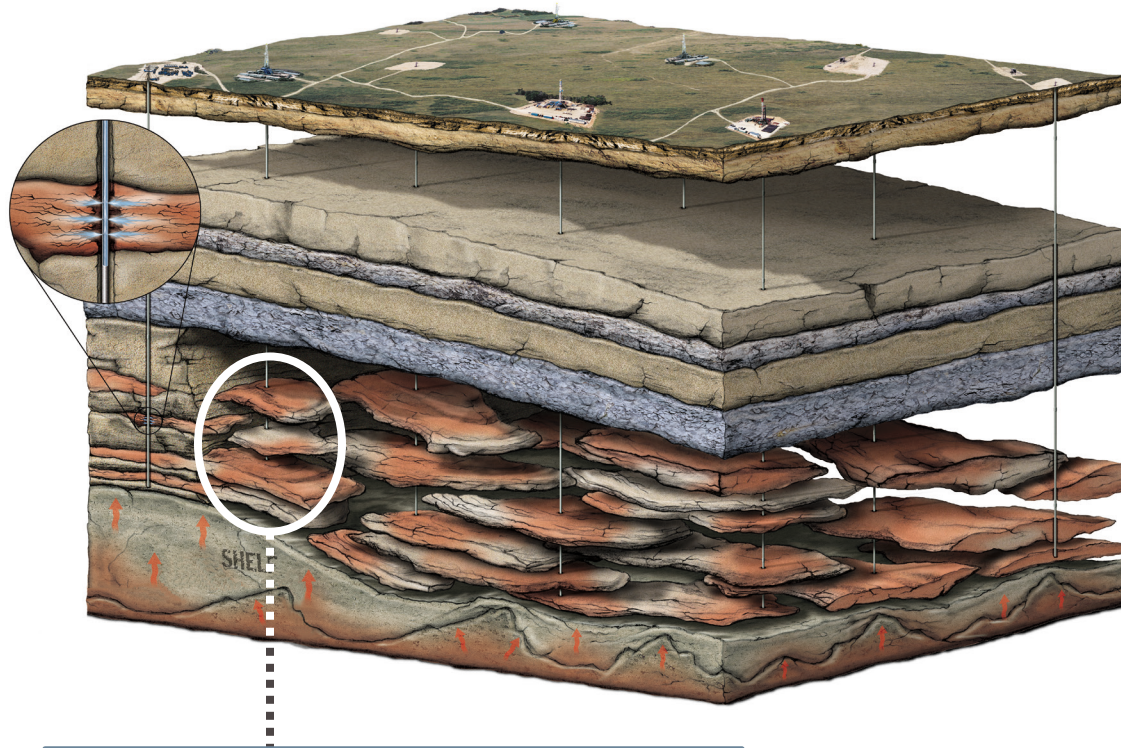
Dorcheat-Macedonia Economics

EUR	152,000 Boe
Peak 30-day Rate	103 Boe/d
% Oil & Liquids	70%
Cost per Well	\$1.8MM
NPV-10 at \$80/BO	\$1.9 MM
NPV-10 at \$100/BO	\$2.8 MM
Engineered Locations	149 net ⁽¹⁾

BTAX IRR % at \$/BO WTI⁽²⁾



Cotton Valley Lenticular Oil Sands

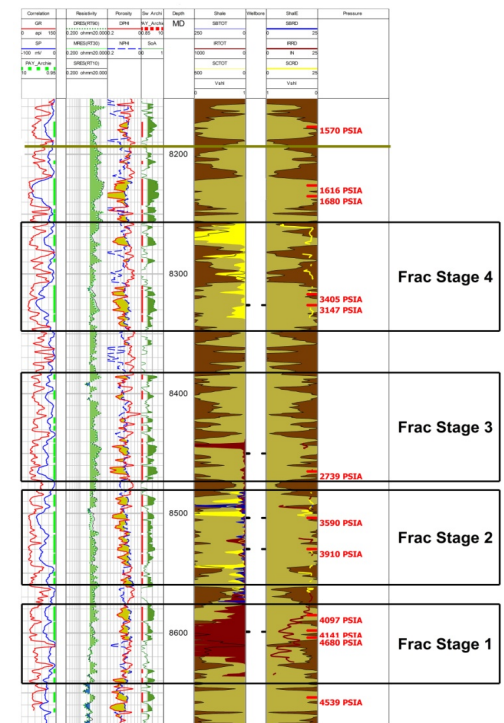


- ◆ 25-30 sand/shale sequences
- ◆ Each zone individually pressured
- ◆ Potential for downspacing inside 10-acres

Pin-Point Fracture Technology

- ◆ Focused completion technology
- ◆ Improved recovery of OOIP
- ◆ Highly repeatable

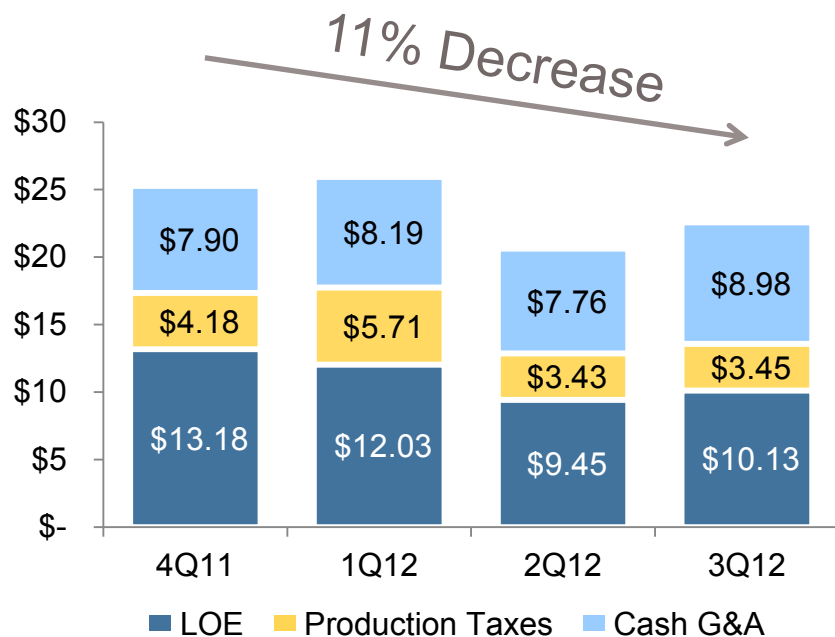
Dorcheat Unit 37



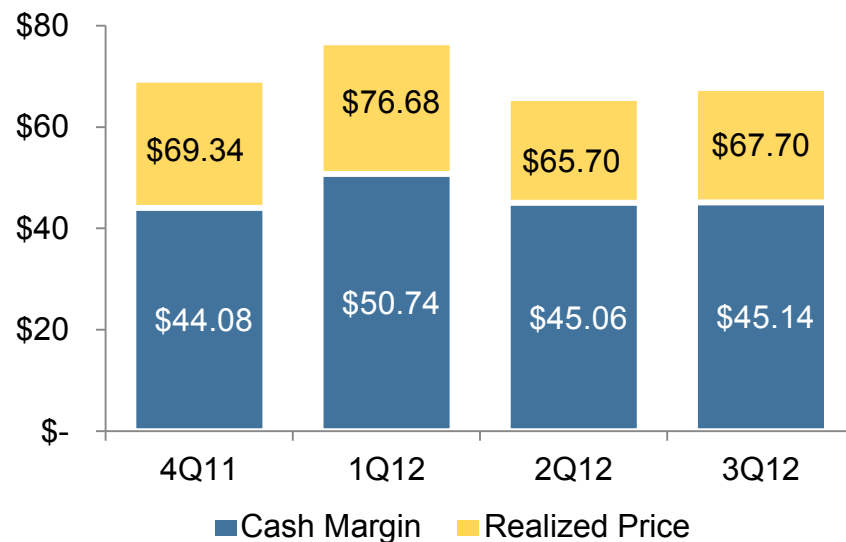
Financial Overview

Improving Operating Cost Structure – High Margins

Cash Costs (\$ per Boe)



Realized Price & Cash Margins (\$ per Boe)



Capitalization & Liquidity

- ◆ Total debt: \$122.3 million
- ◆ <1x Debt-to-EBITDA ratio

(in thousands)	as of September 30, 2012
Capitalization	
Outstanding Balance on Credit Facility	\$122,300
Book value of equity	\$564,365
Total:	\$686,665
Liquidity	
Cash & cash equivalents	\$4,846
Borrowing Base ⁽¹⁾	\$325,000
Amount Outstanding	(\$122,300)
Contractual obligation for land acquisition	(\$48,000)
Total:	\$159,546

Hedge Positions⁽¹⁾

Commodity & Contract Term	Type	Avg. Volume	Avg. Floor	Avg. Ceiling	Avg. Price
Crude Oil		(Bo/Month)			
October 1 – December 31, 2012	Collar	77,956	\$ 90.00	\$ 106.50	
October 1 – December 31, 2012	Swap	49,400			\$ 88.78
January 1 – December 31, 2013	Collar	44,218	\$ 91.61	\$ 106.46	
January 1 – December 31, 2013	Swap	76,285			\$ 88.08
Natural Gas		(MMBTU/Month)			
October 1 – December 31, 2012	Swap	323,103			\$ 3.33
January 1 – October 31, 2013	Swap	15,481			\$ 6.40

Expanding the Runway

- 💧 Experienced management team – proven growth track record
- 💧 Oil & liquids focused – strong cash margins
- 💧 Deep inventory – highly leveraged to the Niobrara
- 💧 Healthy balance sheet – considerable cash flow and credit resources

Corporate Information

Company Headquarters

410 17th Street, Suite 1400
Denver, Colorado 80202
(720) 440-6100 Main
(720) 305-0804 Fax

Houston Office

1331 Lamar Street, Suite 1135
Houston, Texas 77010
(713) 337-1250 Main
(713) 337-1255 Fax

Bakersfield Office

5601 Truxtun Avenue, Suite 210
P.O. Box 21974
Bakersfield, California 93309
(661) 638-2730 Main
(661) 638-2733 Fax

Investor Relations

James M. Masters
Investor Relations Manager
(720) 440-6121
jmasters@bonanzacrk.com

Corporate Data

Symbol / Exchange: BCEI / NYSE
Market Capitalization: \$948 MM⁽¹⁾
52 Week Range: \$12.39 / \$26.60
Shares Outstanding: ~40 MM

Financial Auditor

Hein & Associates LLP

Reserve Auditor

Cawley, Gillespie and Associates, Inc.

www.bonanzacrk.com

Appendix

Experienced Management Team

Mike Starzer

President & CEO

- ◆ Founder of predecessor companies
- ◆ Prior: Executive and Engineering roles at Unocal and Berry Petroleum
- ◆ B.S. in Petroleum Engineering, Colorado School of Mines; M.S. in Engineering Management, University of Alaska; Registered Petroleum Engineer

Gary Grove

*EVP – Engineering & Planning
Interim COO*

- ◆ Joined in 2003 and founder of predecessor company
- ◆ Prior: Managerial and Engineering roles at Unocal and Nuevo Energy
- ◆ B.S. in Petroleum Engineering, Marietta College

Pat Graham

EVP – Corporate Development

- ◆ Joined in 2001 and founder of predecessor company
- ◆ Prior: Managerial and Engineering roles at Dowell Schlumberger and Berry Petroleum
- ◆ B.S. in Petroleum Engineering, Texas A&M University

Wade Jaques

Chief Accounting Officer

- ◆ Joined in 2010 as Controller; promoted to Chief Accounting Officer in 2011
- ◆ Prior: Controller at Ellora Energy Inc. and Audit Manager at Deloitte & Touche
- ◆ B.S. in Accounting, Utah State University

Experienced Management Team

Chris Humber

SVP & General Counsel

- ◆ Joined in 2011 bringing expertise in corporate law, administration, M&A, federal securities laws and stock exchange rules
- ◆ Prior: Kendall, Koenig and Oelsner; Hogan & Hartson; Arnold & Porter
- ◆ B.A. in Biology, University of Colorado; J.D., Emory University School of Law

Lynn Boone

SVP – Reservoir Engineering

- ◆ Joined in 2012 to supervise reservoir engineering activities
- ◆ Prior: Bill Barrett Corp., Cody Energy, HS Resources, and Unocal
- ◆ B.S. in Chemical and Petroleum Refining Engineering, Colorado School of Mines

Ryan Zorn

VP – Finance

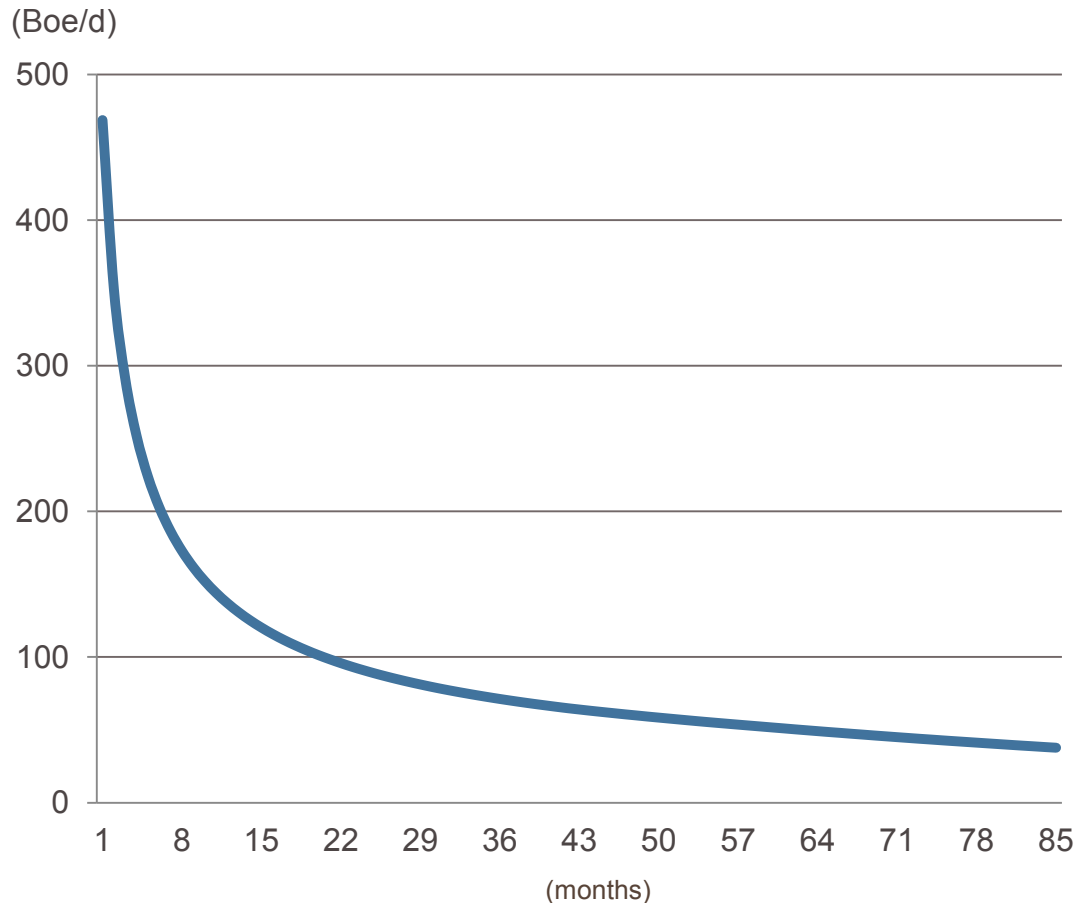
- ◆ Joined in 2012 to direct capital activities, finance and capital markets strategy
- ◆ Prior: Simmons & Co., Goldman Sachs, Saracen Energy Advisors and Bijou Capital
- ◆ B.S. in Economics, Colorado School of Mines

Tony Buchanan

VP – Rocky Mountain Engineering

- ◆ Joined in 2012 to manage engineering and geosciences in the Rocky Mountain region
- ◆ Prior: Noble Energy, Trend Exploration and Mobil E&P
- ◆ B.S. in Petroleum Engineering, Marietta College

Wattenberg Horizontal Niobrara Economics



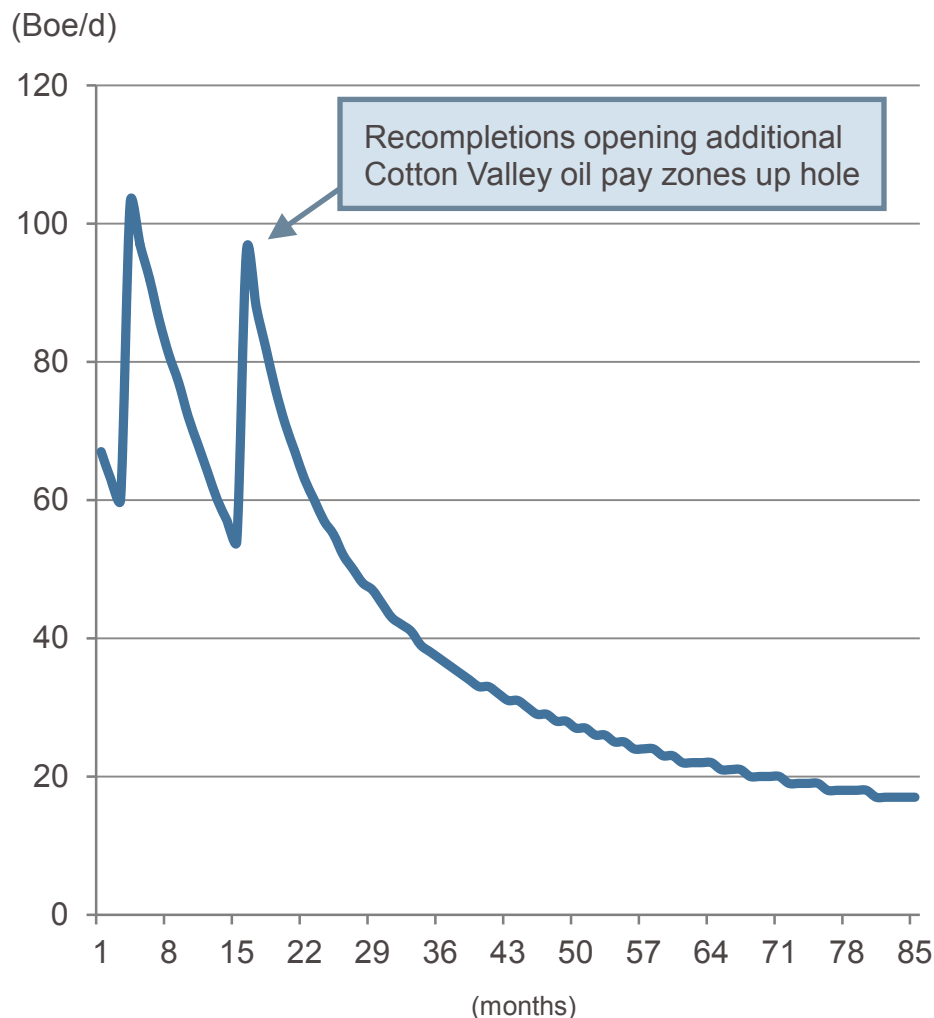
Type Curve⁽¹⁾

- ◆ 312,000 Boe EUR
 - ◆ 65% crude oil; 35% rich gas
- ◆ 356,000 Boe EUR
 - ◆ 57% crude oil; 19% NGLs; 24% dry gas

Field Development

- ◆ 85.6% WI / 69.1% NRI
- ◆ 360 net locations⁽²⁾ at 80 acre spacing

Dorcheat-Macedonia Field



Type Curve⁽¹⁾

- ◆ 152,000 Boe EUR
- ◆ Initial 30-day rate: 67 Boe/d
- ◆ Peak 30-day rate: 103 Boe/d
- ◆ Include subsequent recompletions

Field Development

- ◆ 80.7 WI / 66.4% NRI
- ◆ 149 locations at 10 acre spacing⁽²⁾
- ◆ \$1.7 million CapEx, including two recompletions
- ◆ 12 days to drill; 3 days to complete

Mid-Continent Gas Processing Facilities

General Overview

- ◆ Approximately 150 miles of gathering lines
- ◆ Processes minor quantities of third party natural gas
- ◆ Facilities interconnect into the CenterPoint Energy pipeline system
- ◆ NGL pricing historically averages approximately 66% of WTI (ethane sold in gas stream)

Dorcheat Gas Processing Facility

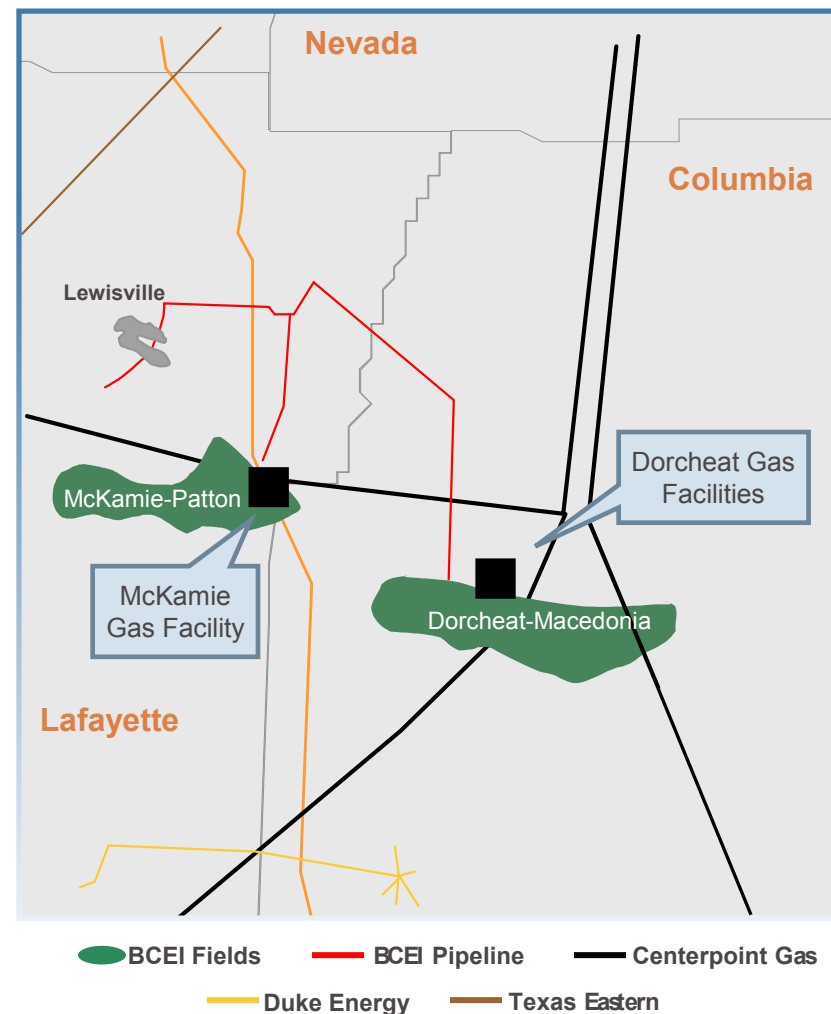
- ◆ 12.5 MMcf/d of natural gas (28,000 gallons per day of natural gas liquids) processing capacity
- ◆ Additional 12.5 MMcf/d of capacity to be online in Q1 2013. Expansion at current Dorcheat site

McKamie Gas Processing Facility

- ◆ 15 MMcf/d of natural gas (30,000 gallons per day of natural gas liquids) processing capacity

Gas Facilities Enhance Total Returns

- ◆ The facility significantly increases EBITDAX margins for the asset over the life of the well
- ◆ Sole ownership and control of facilities allows Company to capture the additional high margin liquids value of the assets, not a third party



Reconciliation to Adjusted Net Income

This release contains the non-GAAP financial measures adjusted net income and adjusted net income per diluted share, which exclude (1) unrealized gain or loss on commodity derivatives, (2) non-cash stock compensation expense, (3) impairment of proved properties and (4) exploratory well abandonment. The amounts included in the calculation of adjusted net income and adjusted net income per diluted share, below, were computed in accordance with GAAP. We believe adjusted net income and adjusted net income per diluted share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. However, these measures are provided in addition to, not as an alternative for and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website. The following tables provide a reconciliation of adjusted net income for the three and nine months ended September 30, 2012 and 2011, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net Income	\$ 3,421	\$ 4,833	\$ 33,473	\$ 12,868
Unrealized (gain) loss in fair value of derivatives	9,007	(8,268)	(2,985)	(7,096)
Stock-based compensation	1,446	133	2,912	133
Impairment	1,917	4,067	1,917	4,067
Exploration	5,846	-	7,379	-
Total adjustments before tax	18,216	(4,068)	9,223	(2,896)
Adjusted for income tax effects	11,203	(2,502)	5,672	(1,781)
Adjusted net income	<u>\$ 14,624</u>	<u>\$ 2,331</u>	<u>\$ 39,145</u>	<u>\$ 11,087</u>
Adjusted net income per diluted share	<u>\$ 0.37</u>	<u>\$ 0.08</u>	<u>\$ 0.97</u>	<u>\$ 0.38</u>

Reconciliation to EBITDAX

We define EBITDAX as net income, plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) stock-based compensation expense, (4) interest expense, (5) unrealized loss (gain) on commodity derivatives, and (6) income taxes. EBITDAX is not a measure of net income or cash flow as determined by GAAP. EBITDAX is presented herein and reconciled to the GAAP measure of net income because of its wide acceptance by the investment community as a financial indicator of a Company's ability to internally fund development and exploration activities. This measure is provided in addition to, not as an alternative for and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website. The following table provides a reconciliation of EBITDAX to net income for the three and nine months ended September 30, 2012 and 2011, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net Income	\$ 3,421	\$ 4,833	\$ 33,473	\$ 12,868
Exploration	6,365	19	9,581	573
Depletion, depreciation, and amortization	18,286	7,304	43,901	21,083
Impairment of proved properties	1,917	4,067	1,917	4,067
Stock-based compensation	1,446	133	2,912	133
Gain on sale of oil and gas properties	(4,280)	-	(4,280)	-
Interest expense	1,126	1,122	2,342	2,687
Unrealized loss (gain) on commodity derivatives	9,007	(8,268)	(2,985)	(7,096)
Income taxes (benefit)	2,315	6,771	21,129	11,464
EBITDAX	<u>\$ 39,603</u>	<u>\$ 15,981</u>	<u>\$ 107,990</u>	<u>\$ 45,779</u>
EBITDAX per diluted share	<u>\$ 1.00</u>	<u>\$ 0.55</u>	<u>\$ 2.74</u>	<u>\$ 1.57</u>

Reconciliation to Discontinued Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
NET REVENUES				
Oil and gas sales	\$ 58,328	\$ 25,915	\$ 157,613	\$ 70,609
OPERATING EXPENSES:				
Lease operating	8,444	4,686	22,506	12,041
Severance and ad valorem taxes	3,022	1,343	9,387	3,779
Exploration	6,359	19	9,564	566
Depreciation, depletion and amortization	17,716	6,330	41,751	18,472
Impairment of proved properties	269	623	269	623
General and administrative	9,335	4,179	22,410	9,116
Total operating expenses	45,145	17,180	105,887	44,597
INCOME FROM OPERATIONS	13,183	8,735	51,726	26,012
OTHER INCOME (EXPENSE):				
Other income (loss)	(91)	(3)	(83)	(101)
Interest expense	(1,125)	(1,122)	(2,342)	(2,687)
Unrealized (loss) in fair value of commodity derivatives	(9,007)	8,268	2,985	7,096
Realized (loss) in fair value of commodity derivatives	(93)	(519)	(1,173)	(2,353)
Total other income (loss)	(10,316)	6,624	(613)	1,955
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	\$ 2,867	\$ 15,359	\$ 51,113	\$ 27,967
Income tax expense	(1,223)	(8,528)	(19,797)	(13,176)
INCOME FROM CONTINUING OPERATIONS	1,644	6,831	31,316	14,791
DISCONTINUED OPERATIONS				
Income (loss) from operations associated with oil and gas properties held for sale	(1,410)	(3,755)	(792)	(3,635)
Gain on sale of oil and gas properties	4,280	-	4,280	-
Income tax (expense) benefit	(1,093)	1,757	(1,331)	1,713
Income associated with oil and gas properties held for sale	1,777	(1,998)	2,157	(1,922)
NET INCOME	\$ 3,421	\$ 4,833	\$ 33,473	\$ 12,869
BASIC AND DILUTED INCOME PER SHARE				
Income from continuing operations	\$ 0.04	\$ 0.23	\$ 0.79	\$ 0.51
Income (loss) from discontinued operations	\$ 0.05	\$ (0.06)	\$ 0.06	\$ (0.07)
WEIGHTED AVERAGE NUMBER OF SHARES OF COMMON STOCK—BASIC AND DILUTED	39,477	29,123	39,476	29,123

3Q 2012 Sales Volumes	
Continuing Operations	9,402 Boe/d
Discontinued Operations	143 Boe/d
Total	9,545 Boe/d