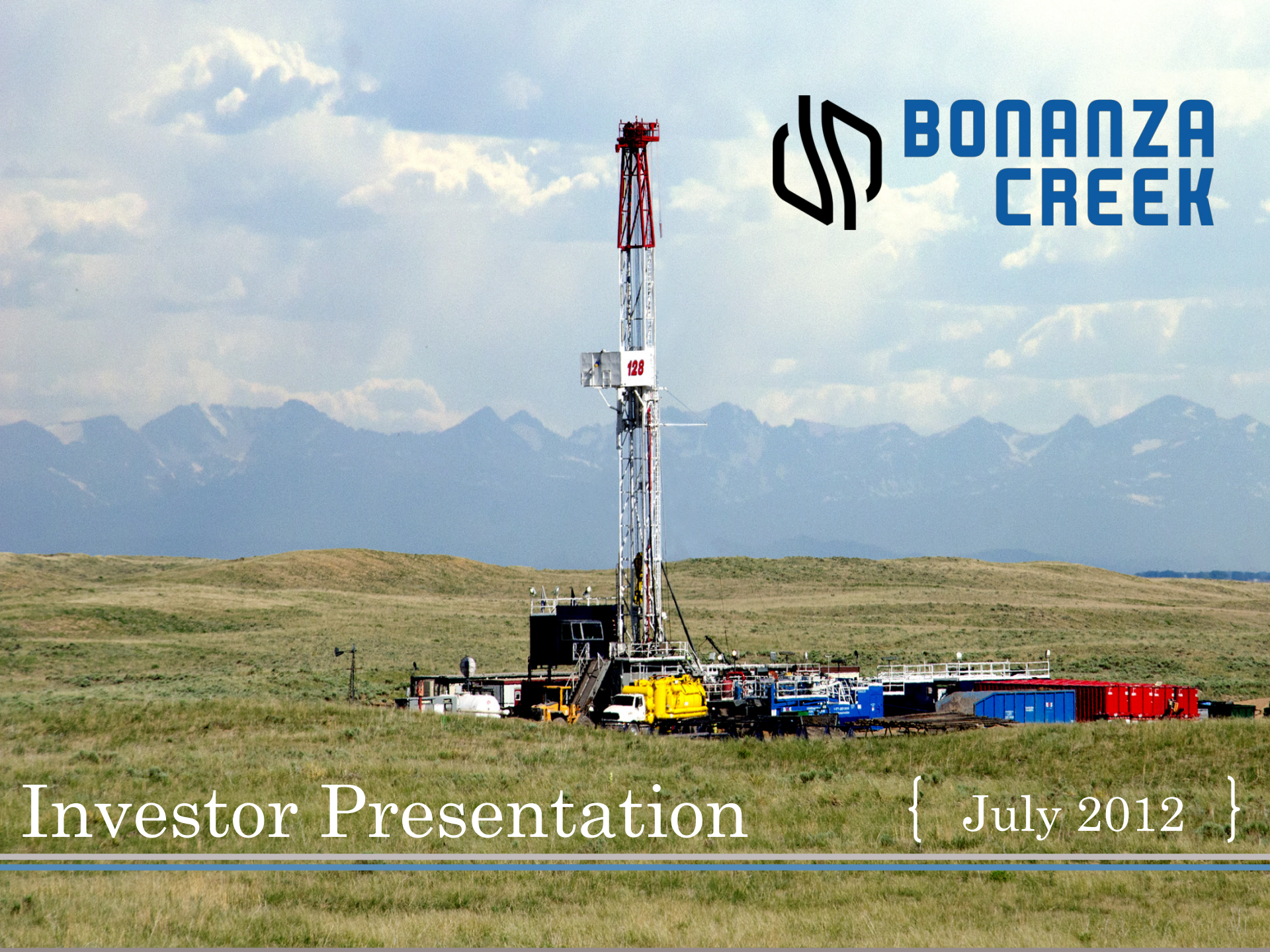


Investor Presentation

{ July 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, unrisked 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.

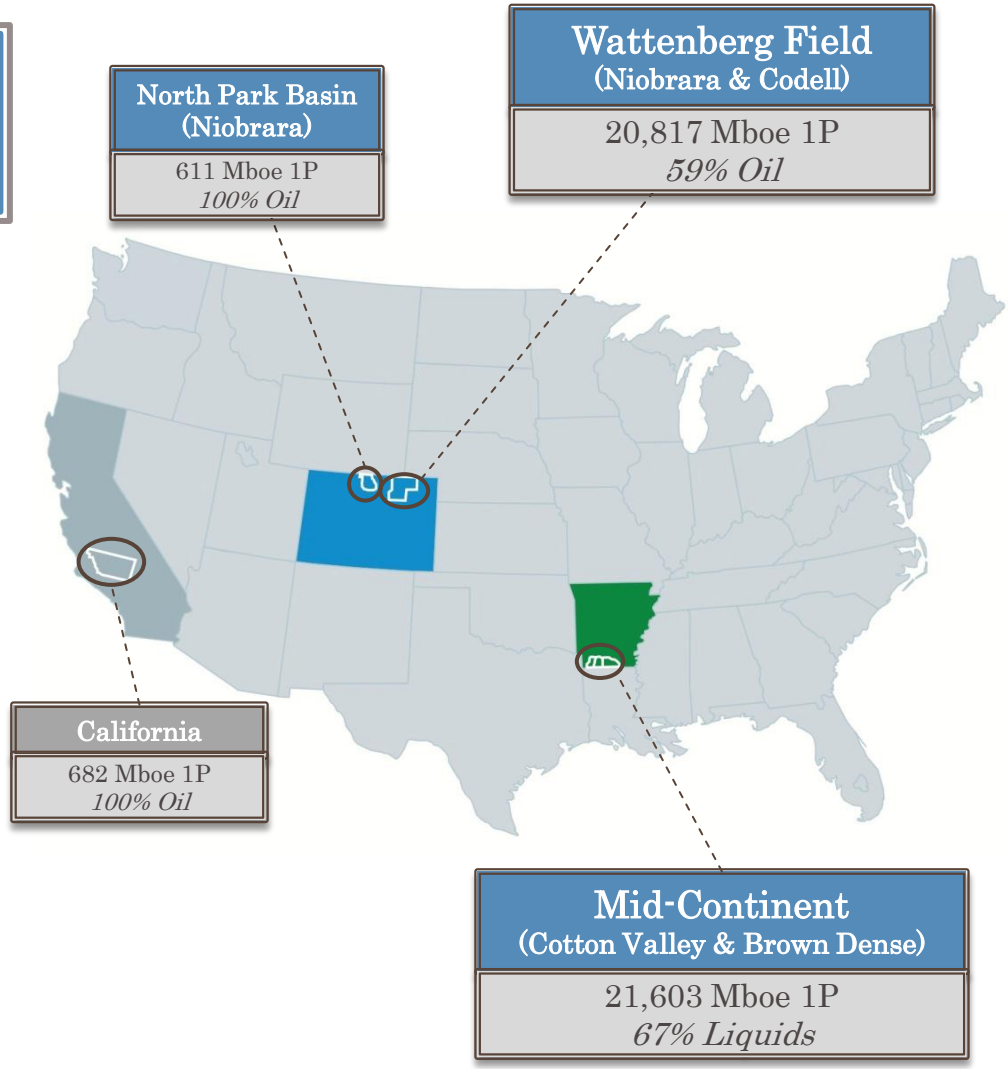
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Bonanza Creek Overview

BCEI LISTED NYSE

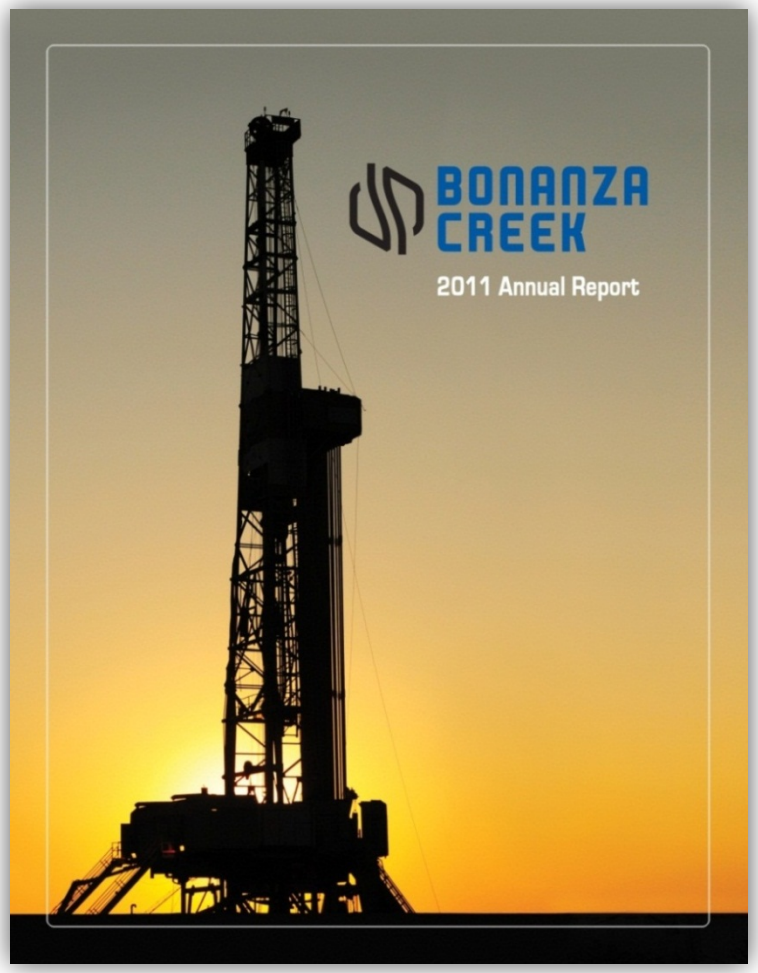
Market Cap:	$657 million
Share Price[1]:	$16.63
Shares Outstanding[2]:	39.5 million

- 100+% Production Growth in 2012
- 250 MMBoe resource potential[3]
- Strong Balance Sheet
- Proven Management



(1) Stock price as of 6/29/2012
(2) Common shares outstanding as of 3/31/2012
(3) Total resource potential includes 43.7 MMBoe of proved reserves, at YE 2011; the remainder based on internal estimates

First Quarter 2012 Highlights



96% Increase in Production[(1)]

- 646 Mboe (7,100 Boe/d)
- 76% oil and liquids

132% Increase in EBITDAX[(1) (2)]

- $31.5 million ($0.80/sh)

541 Boe/d Avg. 30-day Rate – Niobrara Hz

- 486 Boe/d, 72% oil, average for all 6 Hz wells

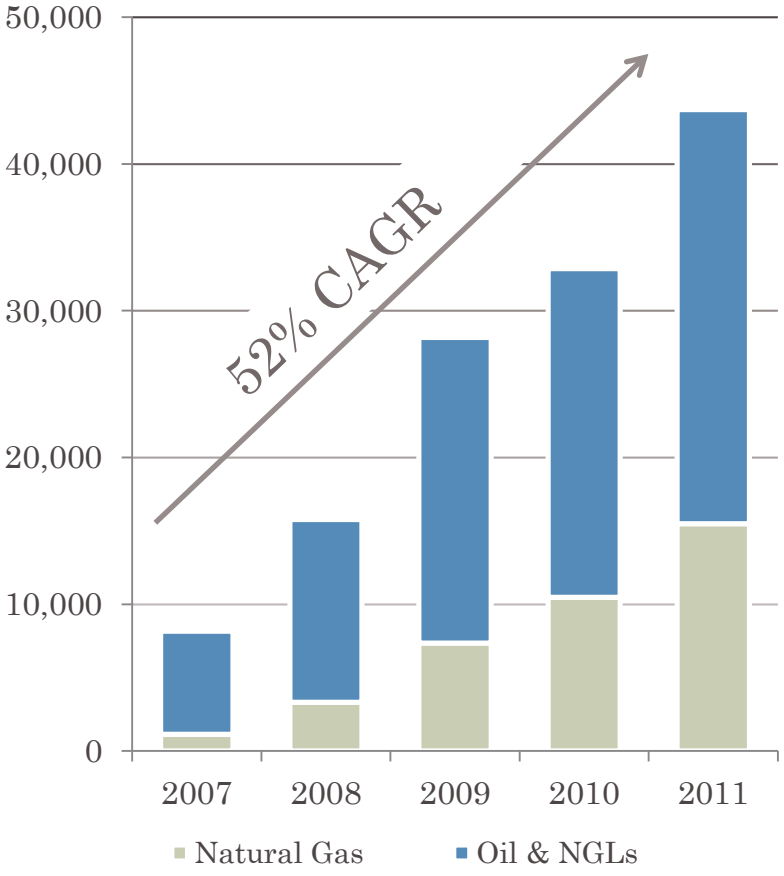
$245 million borrowing base[(3)]

- $600 million credit facility
- $223 million of liquidity

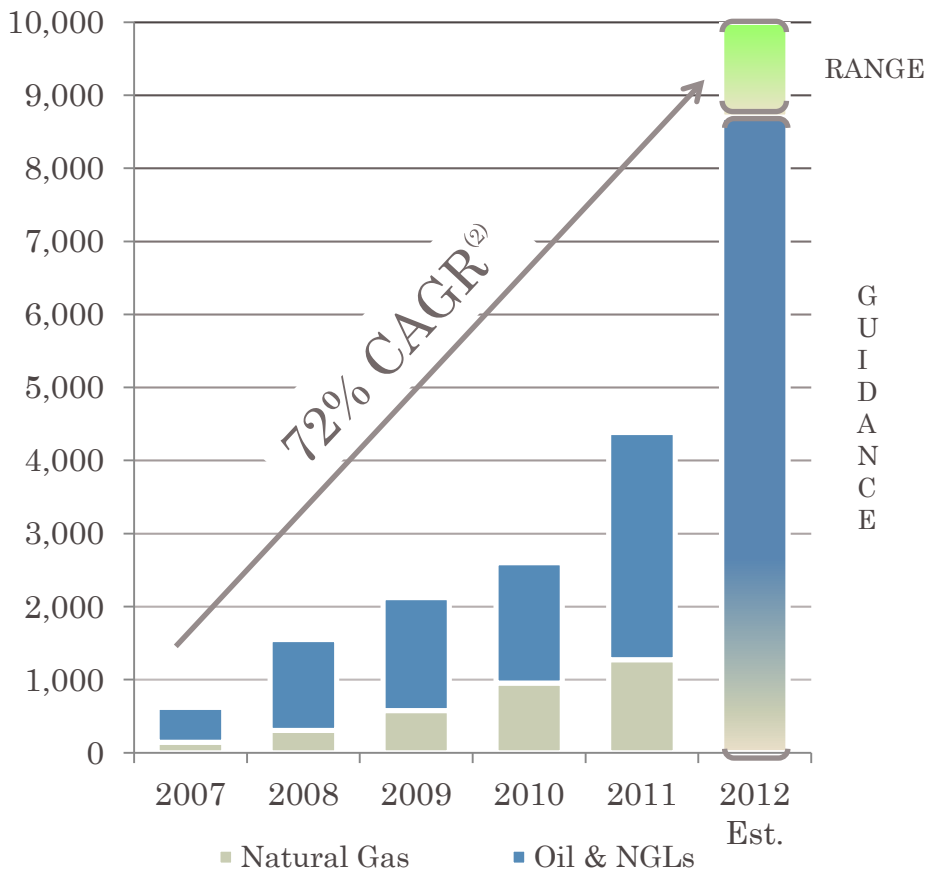
(1) As compared to 1Q 2011
(2) See EBITDAX reconciliation in Appendix
(3) On 5/8/2012 credit agreement was amended to increase facility to $600 million; borrowing base increased to $245 million from $220 million. At 3/31/2012, debt outstanding was $21.6 million

Robust Growth in Reserves and Production

Proved Reserves[1] (Mboe)



Production[1] (Boe/d)

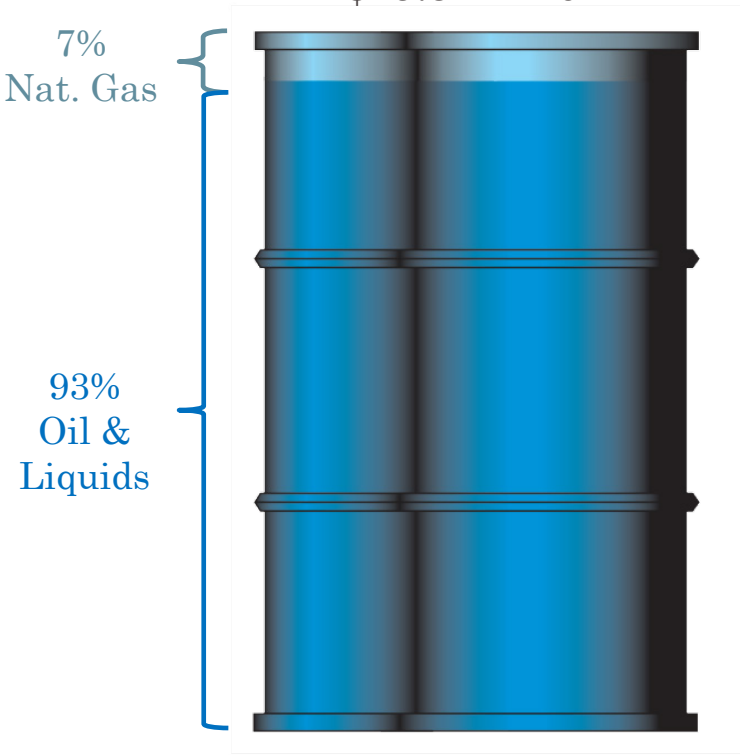


(1) Presentation is pro forma for the December 23, 2010 Holmes Eastern Company acquisition, as if it were completed on May 1, 2009
(2) Production CAGR calculated to the mid-point of the guidance range

Significant Leverage to Oil & Liquids

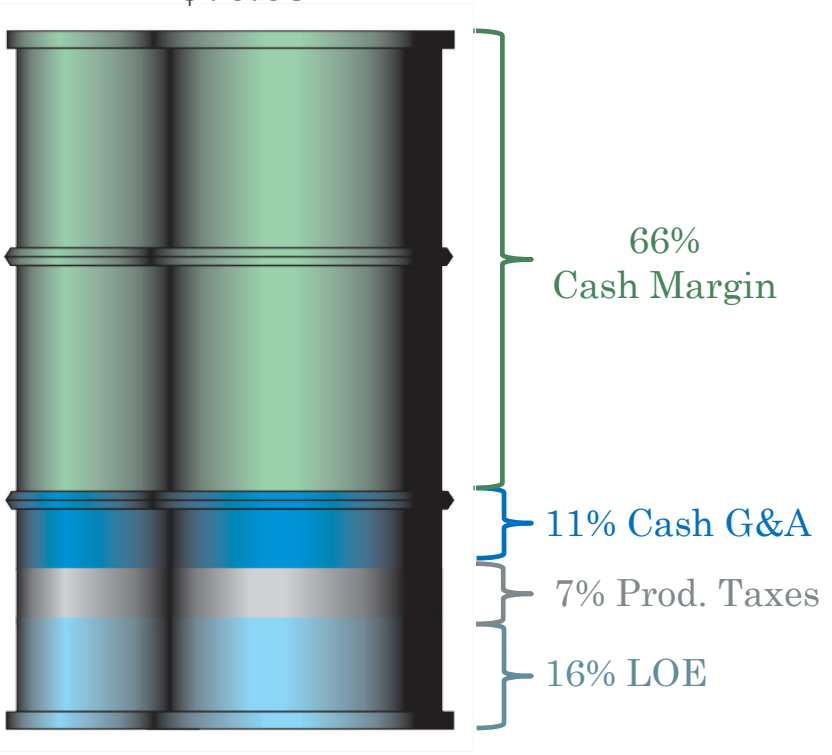
1Q 2012 Revenue

$49.5 Million



Cash Margin / Boe

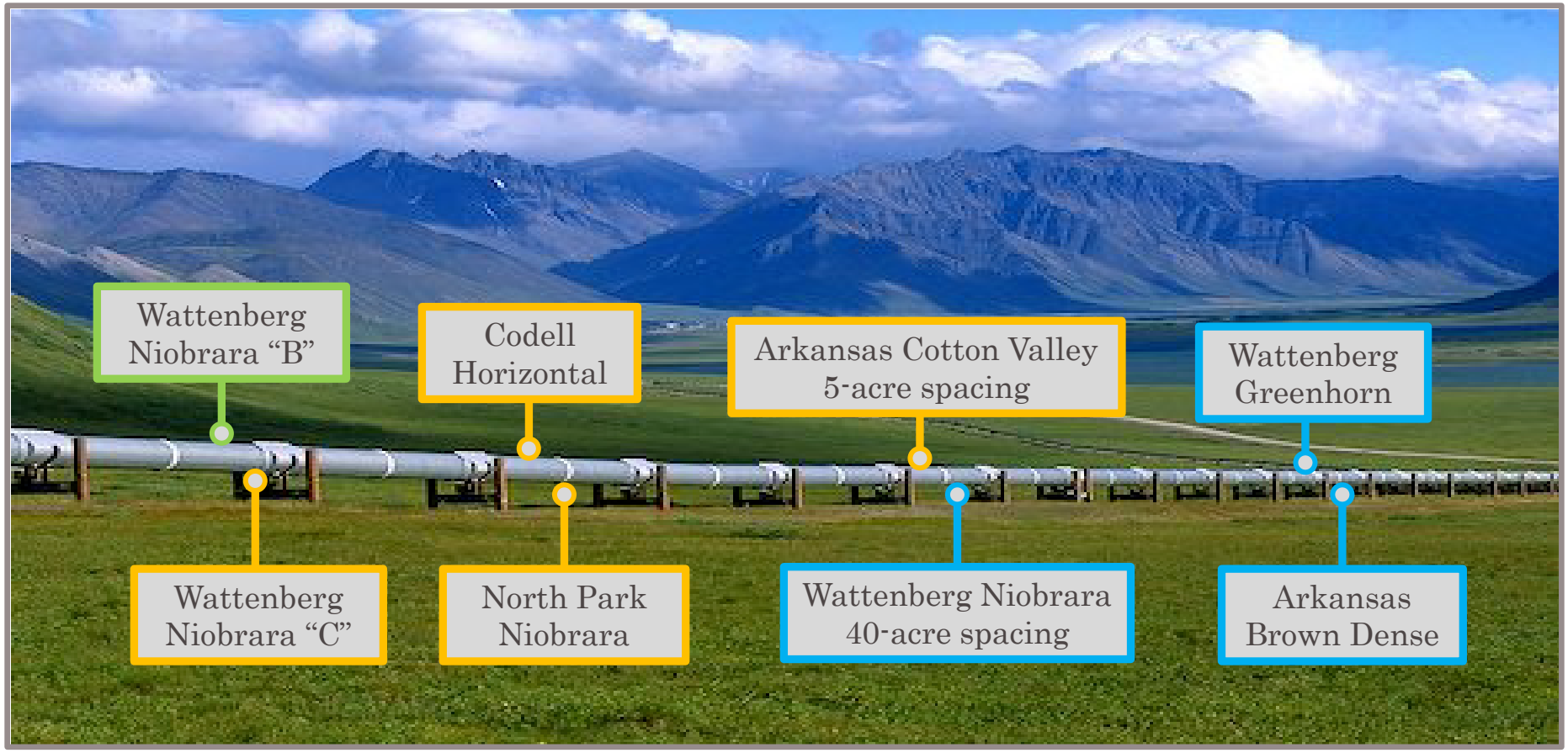
$76.68[(1)]



(1) Average sales price for a barrel of oil equivalent before the effects of hedging for first quarter 2012

Organic Growth Pipeline

- 250 MMBoe of resource potential
- 8 primary opportunities in various stages of development and evaluation



Full Development Testing Evaluating

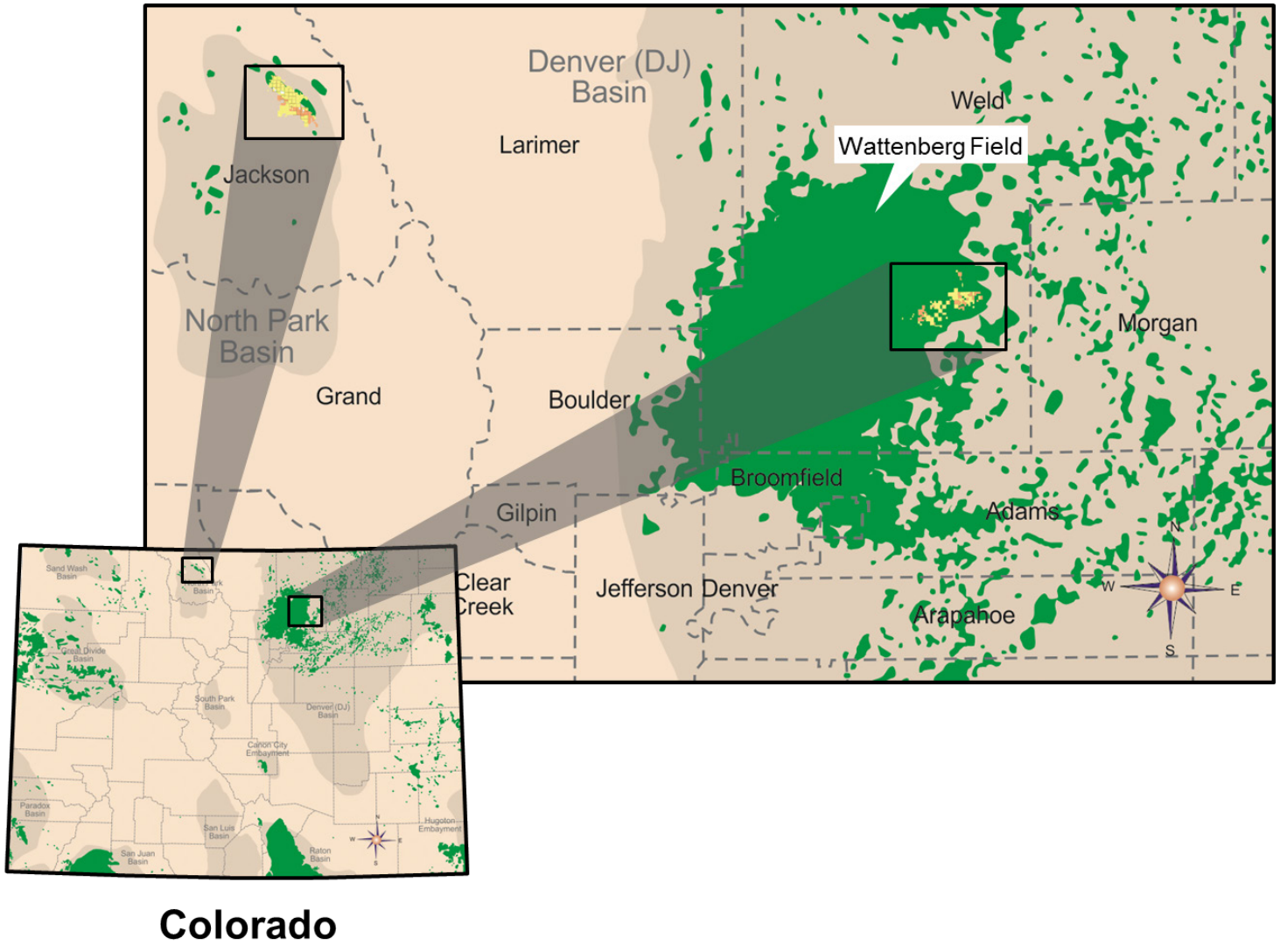
(1) Resource potential based on internal estimates; not included in proved reserves or reviewed by third party. Please see the forward looking statement disclosure on page 2 of this presentation and review associated risk factors.

Capital and Drilling Activity

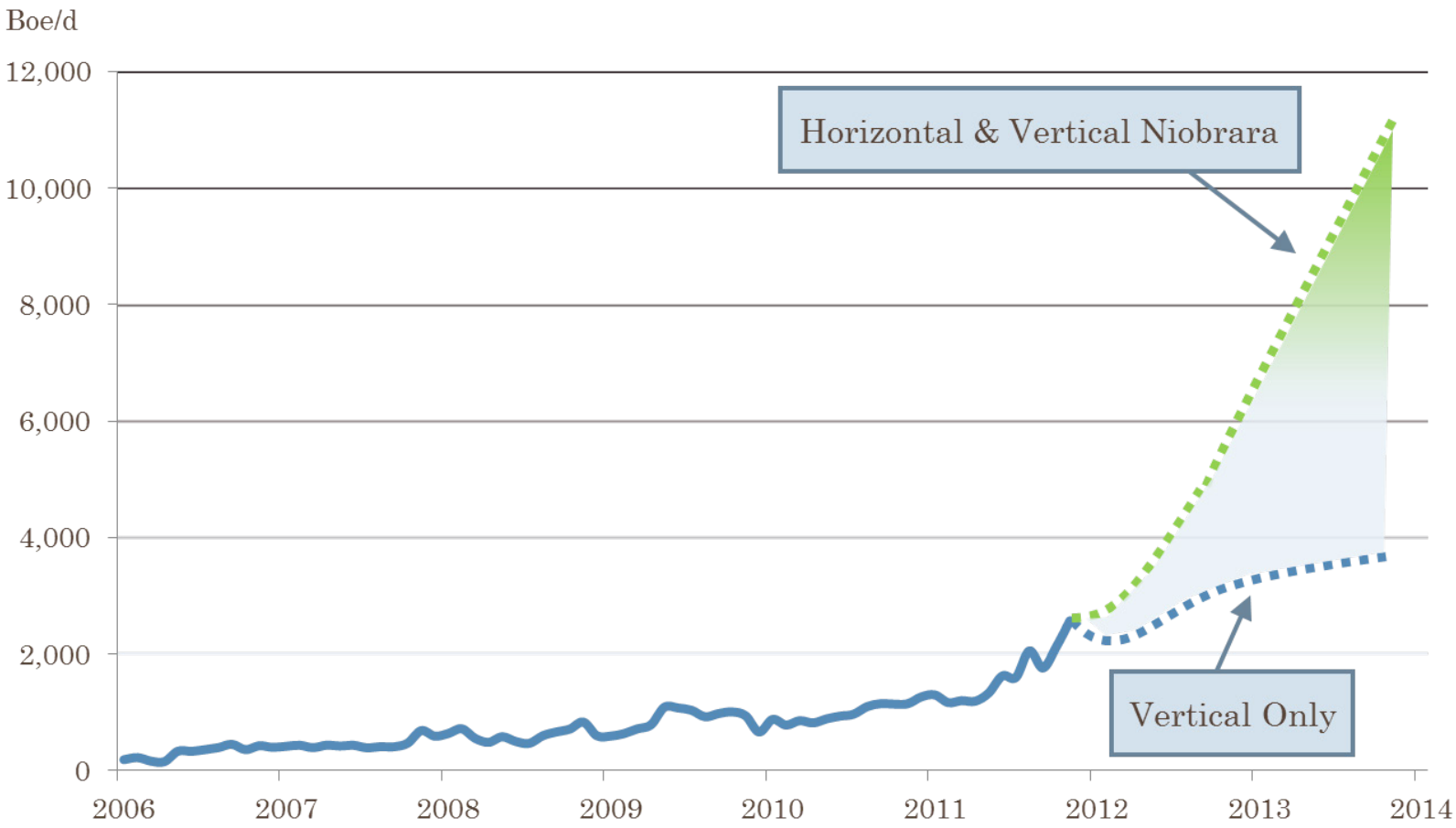
2011 Capital: $165 MM		2012 Capital[(1)]: $250 MM
Vertical: $56 MM • 66 wells (Wattenberg) • 2 wells (North Park) **Horizontal: $21 MM** • 4 wells (Wattenberg)	ROCKY MOUNTAINS	**Vertical: $72 MM** • 92 wells **Horizontal: $99 MM** • 24 wells (Wattenberg) • 3 wells (North Park)
Upstream: $66 MM • 42 wells **Gas Plant: $22 MM** • 12.5 MMcf/d facility	MID-CONTINENT	**Upstream: $59 MM** • 38 wells **Gas Plant: $20 MM** • 12 MMcf/d facility

(1) 2012 approved capital budget

Rocky Mountain Operations

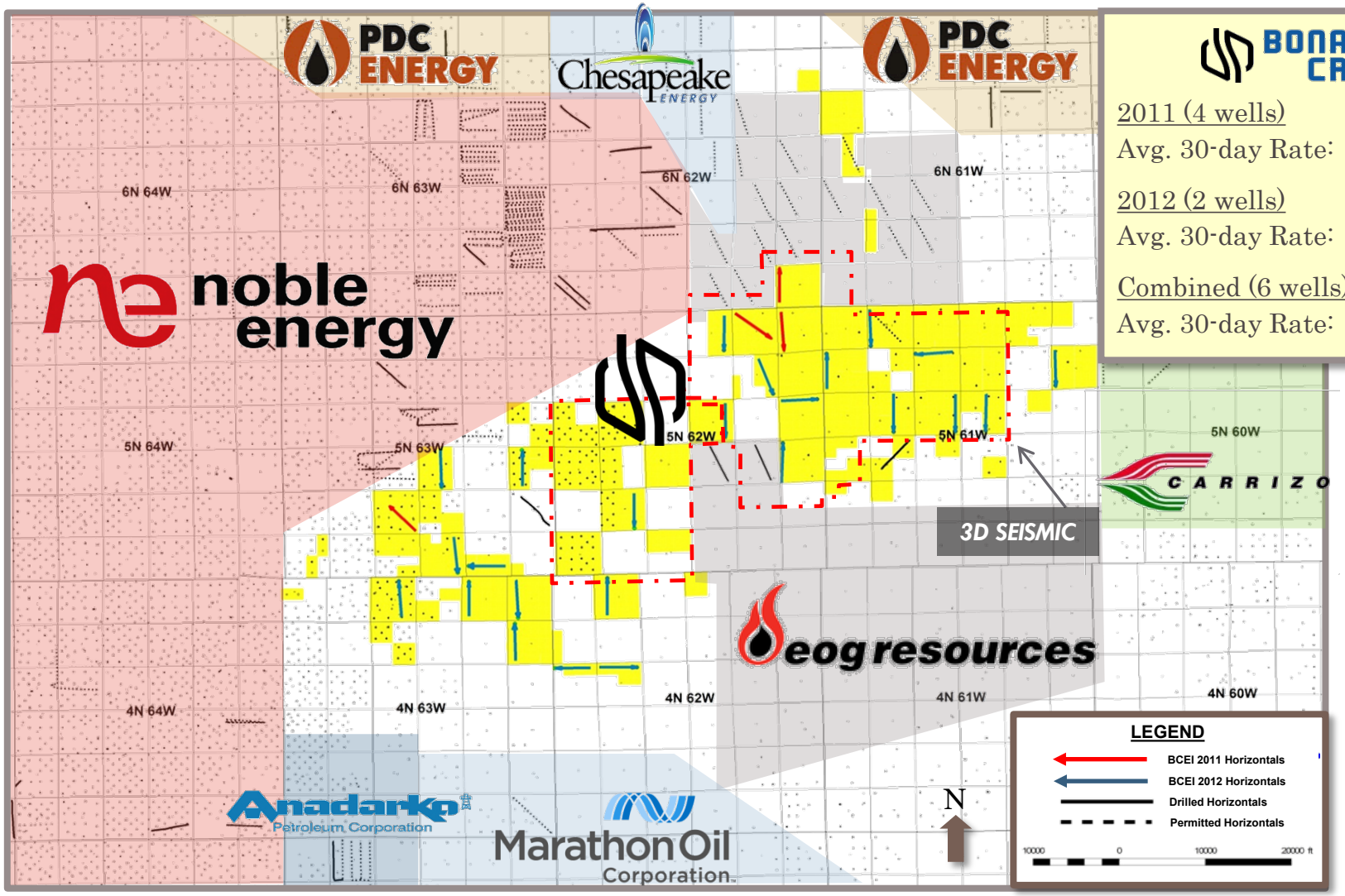


Rocky Mountain Production Potential



(*) Potential production reflects certain assumptions, including capital expenditures based on company liquidity, timing and results of drilling, and commodity prices which management deems reasonable at present. The company makes these assumptions based on management's experience, current conditions and anticipated future developments, and provides no assurance to their accuracy.

Tremendous Results from Wattenberg Niobrara



BONANZA CREEK

2011 (4 wells)
Avg. 30-day Rate: 458 Boe/d

2012 (2 wells)
Avg. 30-day Rate: 541 Boe/d

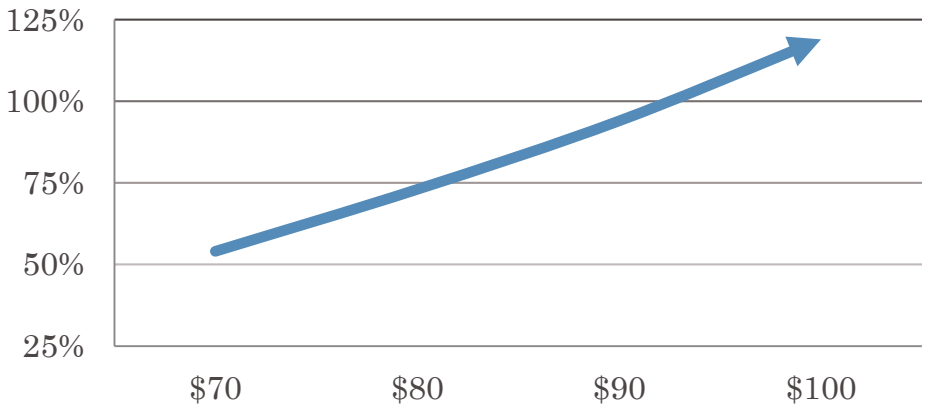
Combined (6 wells)
Avg. 30-day Rate: 486 Boe/d

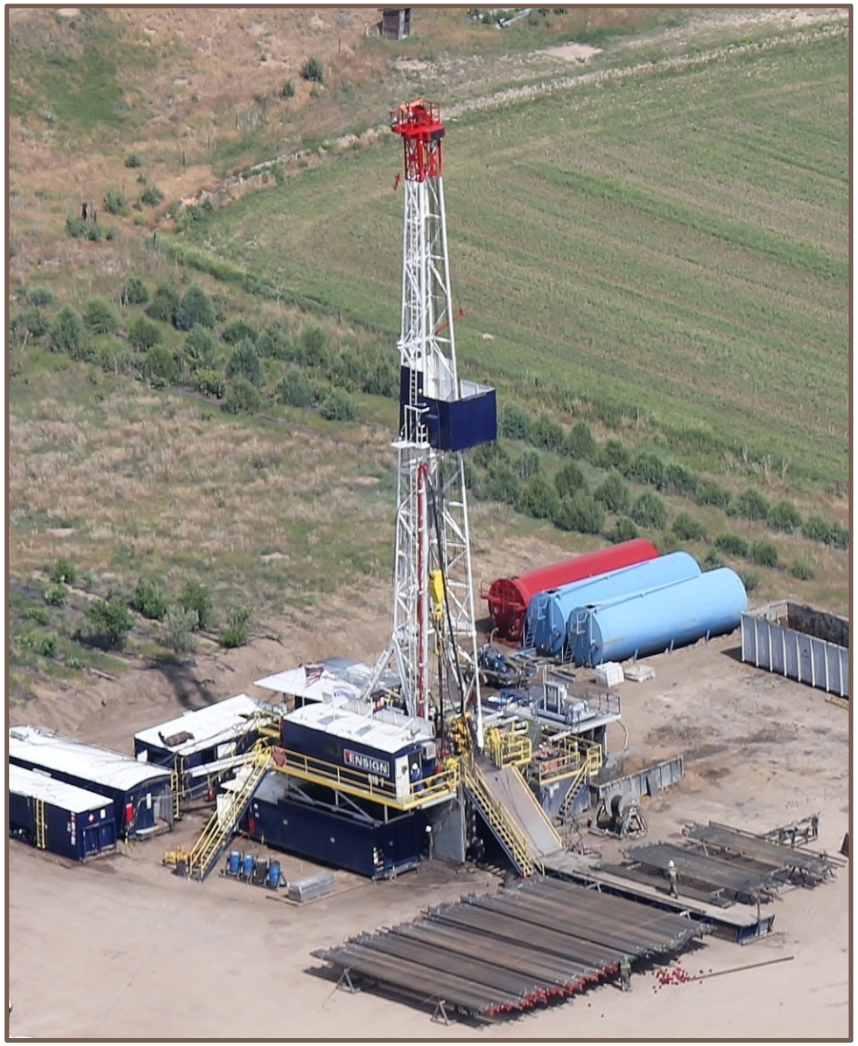
(*) Not intended to reflect offset operators' actual acreage positions

Wattenberg Horizontal Niobrara Economics

EUR	**312,000 Boe; 65% crude oil**
Initial 30-day Rate	469 Boe/d
Cost per Well	$4.0 MM
NPV-10 at $80/BO	$4.1 MM
NPV-10 at $100/BO	$6.1 MM
Locations	290 net[(1)]

IRR % at $/BO WTI[(2)]





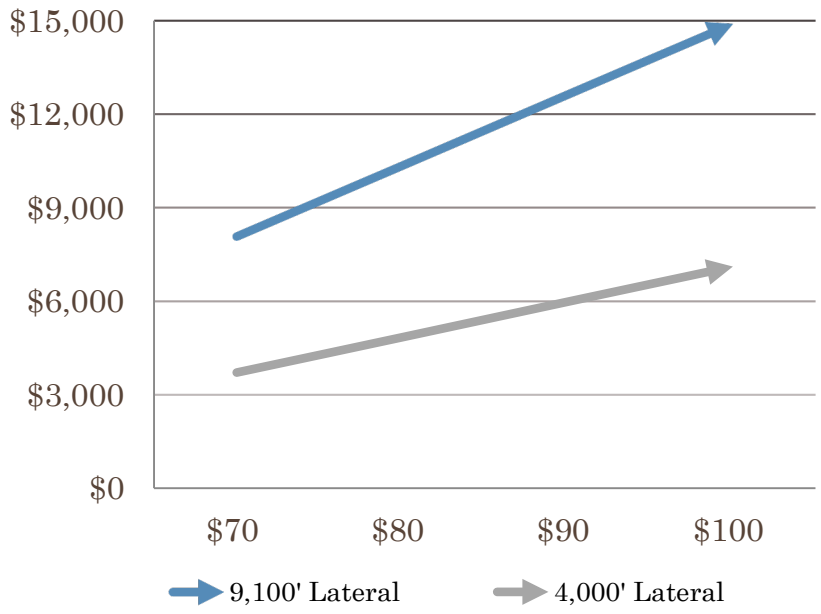
(1) As of December 31, 2011
(2) Natural gas reflected at 18:1 to crude oil for price; 6:1 for rate

Wattenberg Performance & Inventory Upside

1) Extended Reach Laterals

- NBL: 750 MBoe EUR[(1)]
- NBL: $7.5 MM well cost (reported)
- Dramatically improves F&D cost and returns

Comparative PV_{10} ($000's)



2) Niobrara "C" Bench Horizontal

- No evidence of "C" bench stimulation from "B" bench fracs
- C Bench present on all Wattenberg acreage
  - Similar economics to Niobrara "B"
  - Could double 4,000 ft. lateral inventory in the Niobrara

3) Codell Horizontal Development

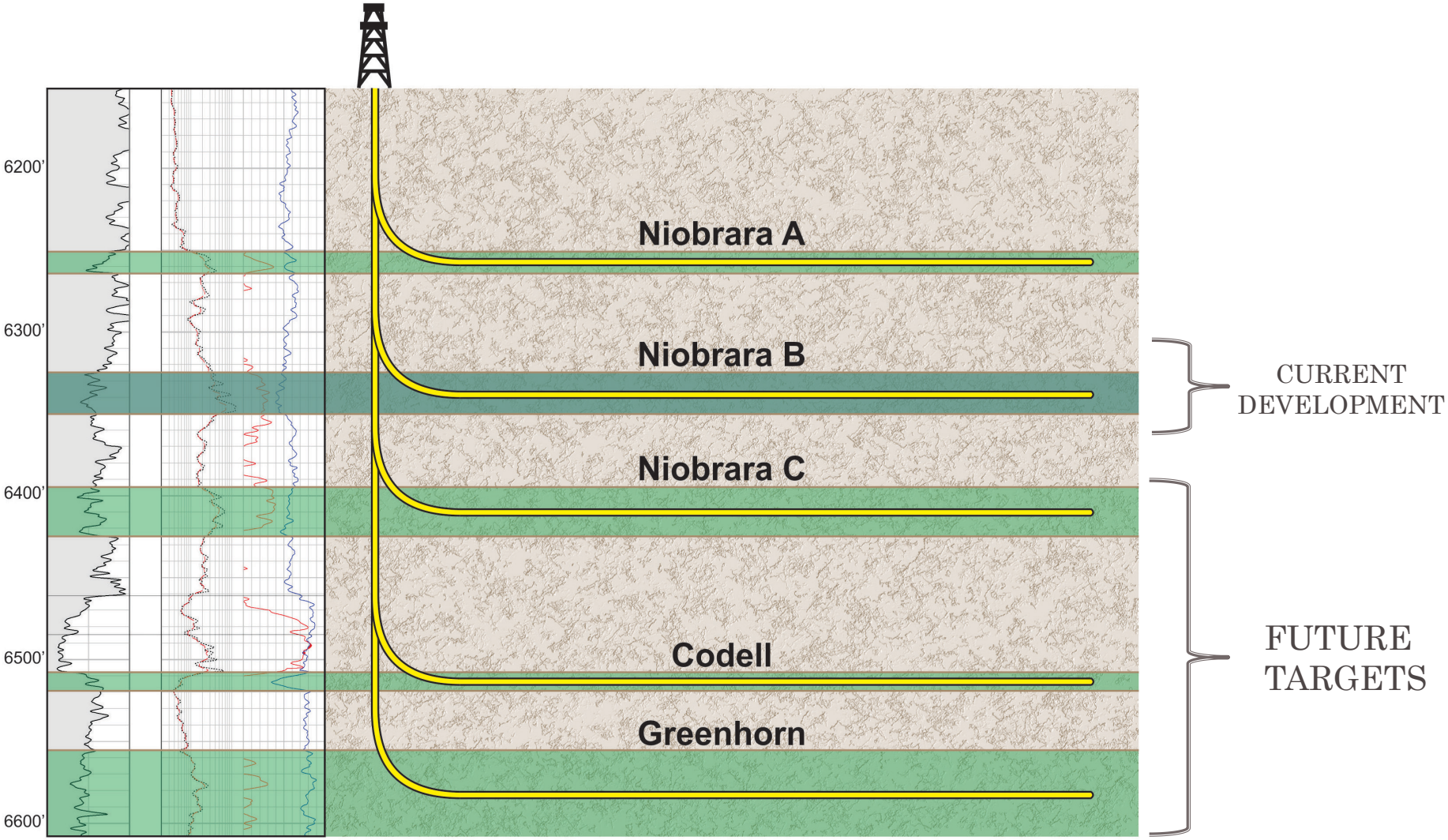
- Anadarko Results[(2)] (30-day rate)
  - PSC 12C-13HZ: 486 BOEPD
  - PSC 13C-13HZ: 441 BOEPD
- Codell present on ~14,000 net acres to BCEI
  - Similar economics to Niobrara "B" 4,000 ft. laterals

4) Downspacing to 40-acres

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

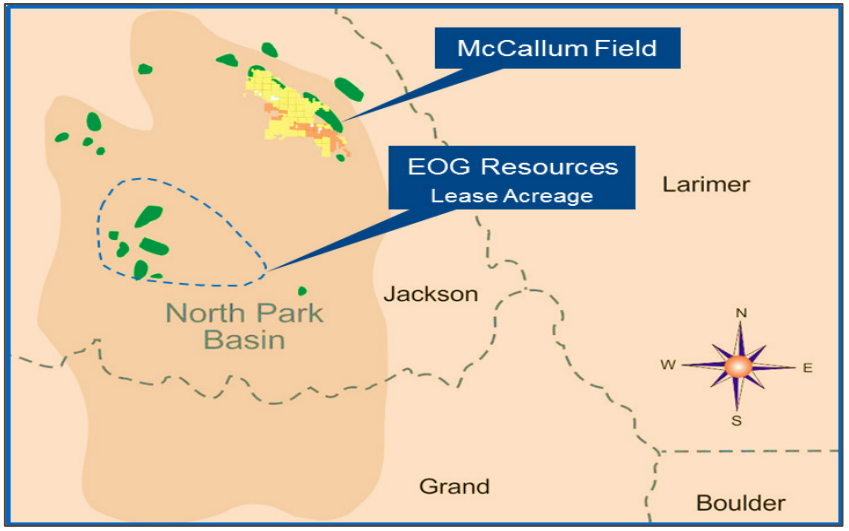
(1) Noble Energy June 2012 investor presentation
(2) Colorado Oil and Gas Conservation Commission

Wattenberg Inventory Targets

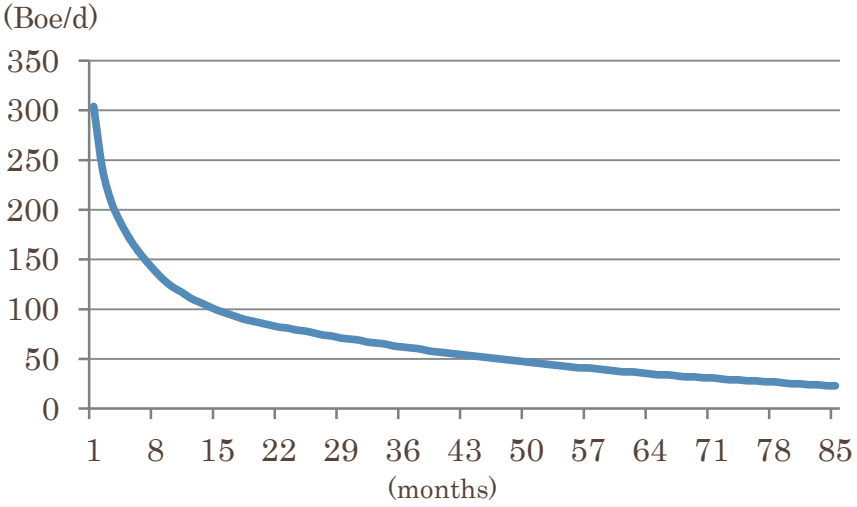


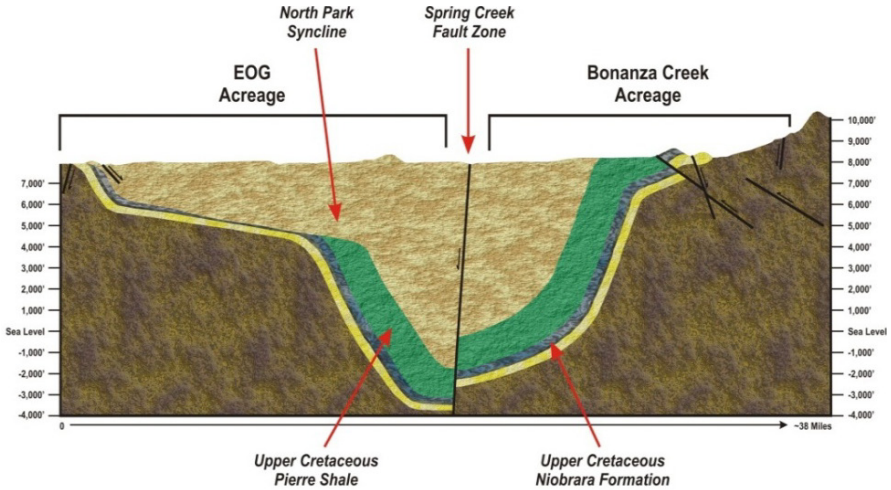
North Park Basin Niobrara

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



Type Curve[1]

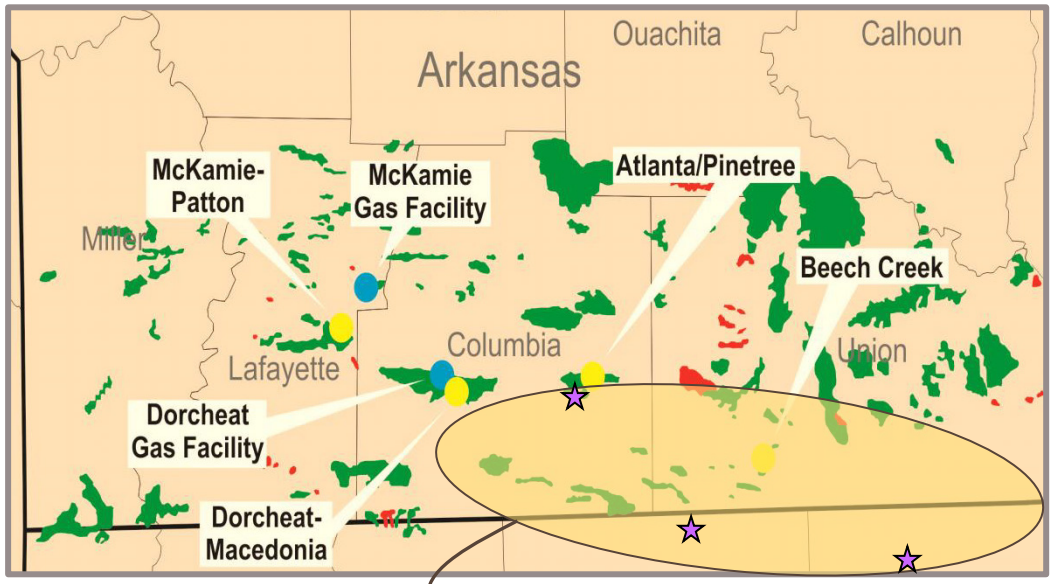




(1) Natural gas reflected at 18:1 to crude oil for price; 6:1 for rate. Type curve based on EOG well results.

Mid-Continent Operations (Arkansas)

- 14,980 gross (13,474 net) acres; 100% HBP
- Primary Target: Cotton Valley: 4,000 – 7,000 feet
- Two gas processing facilities: 28 MMcf/d capacity
- Resource Potential: Lower Smackover / Brown Dense

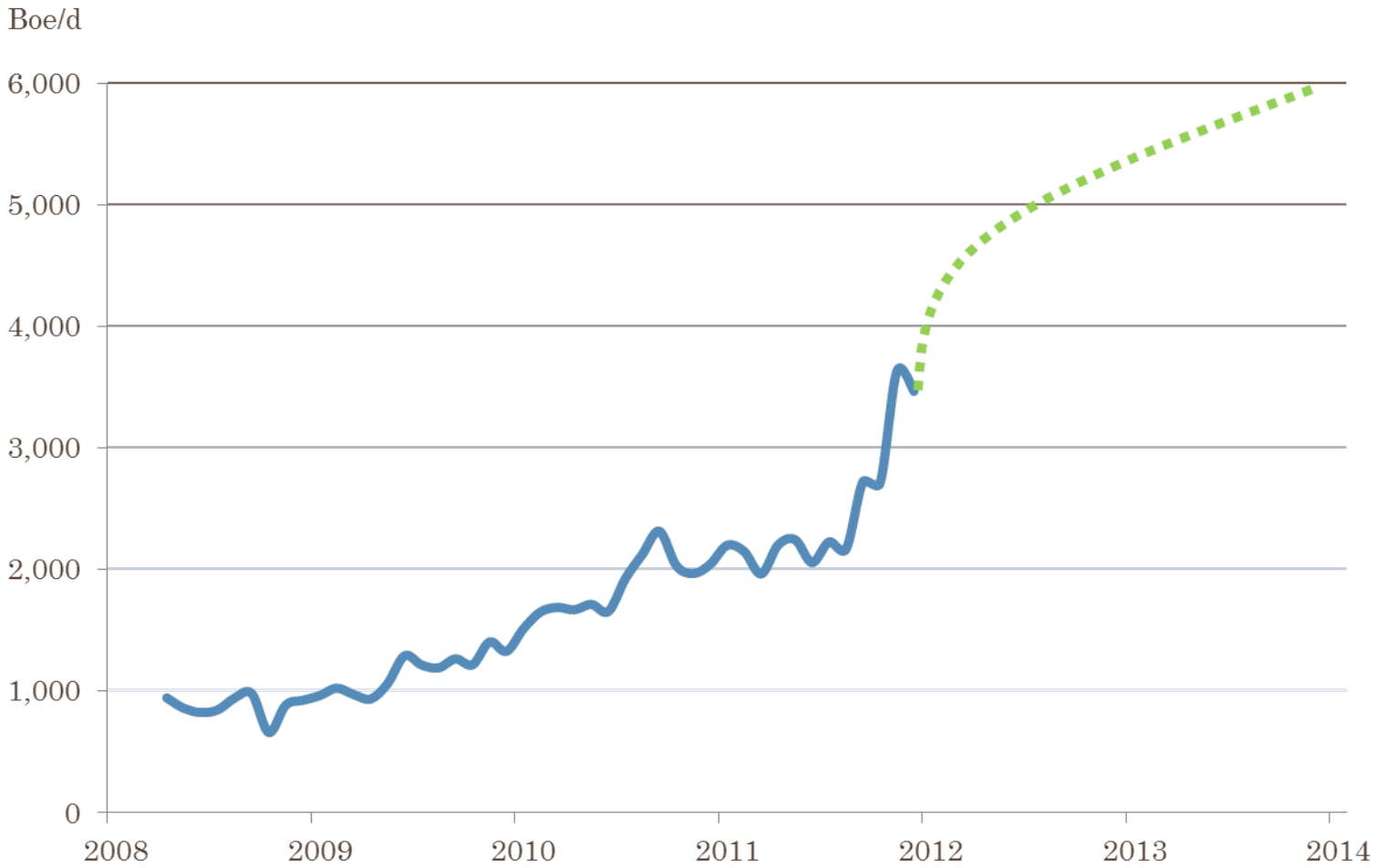


Bonanza Creek Fields
SWN Brown Dense Wells
Bonanza Creek Gas Processing Facilities
Industry Activity in Lower Smackover / Brown Dense

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
			Fredericksburg	Kiamichi
				Goodland Lime
				Paluxy / Walnut
			Trinity	Glen Rose: Upper Glen Rose
				Glen Rose: Massive Anhydrite
				Glen Rose: Rodessa
				Glen Rose: Bexar
				Glen Rose: James
				Glen Rose: Pine Island
				Glen Rose: 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

Mid-Continent Long-Life Growth Potential

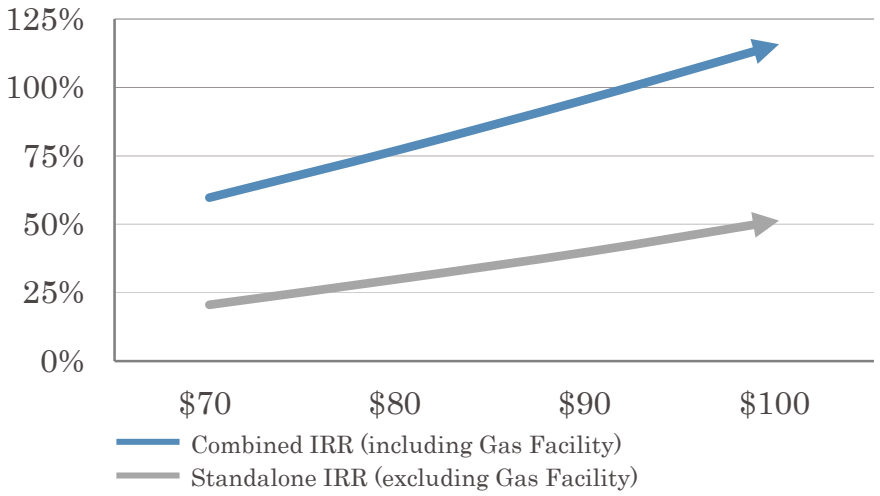


(*) Potential production reflects certain assumptions, including capital expenditures based on company liquidity, timing and results of drilling, and commodity prices which management deems reasonable at present. The company makes these assumptions based on management's experience, current conditions and anticipated future developments, and provides no assurance to their accuracy.

Dorcheat-Macedonia Economics

EUR	**152,000 Boe**
Peak 30-day Rate	103 Boe/d
% Oil & Liquids	70%
Cost per Well	$1.7MM
NPV-10 at $80/BO	$1.9 MM
NPV-10 at $100/BO	$2.8 MM

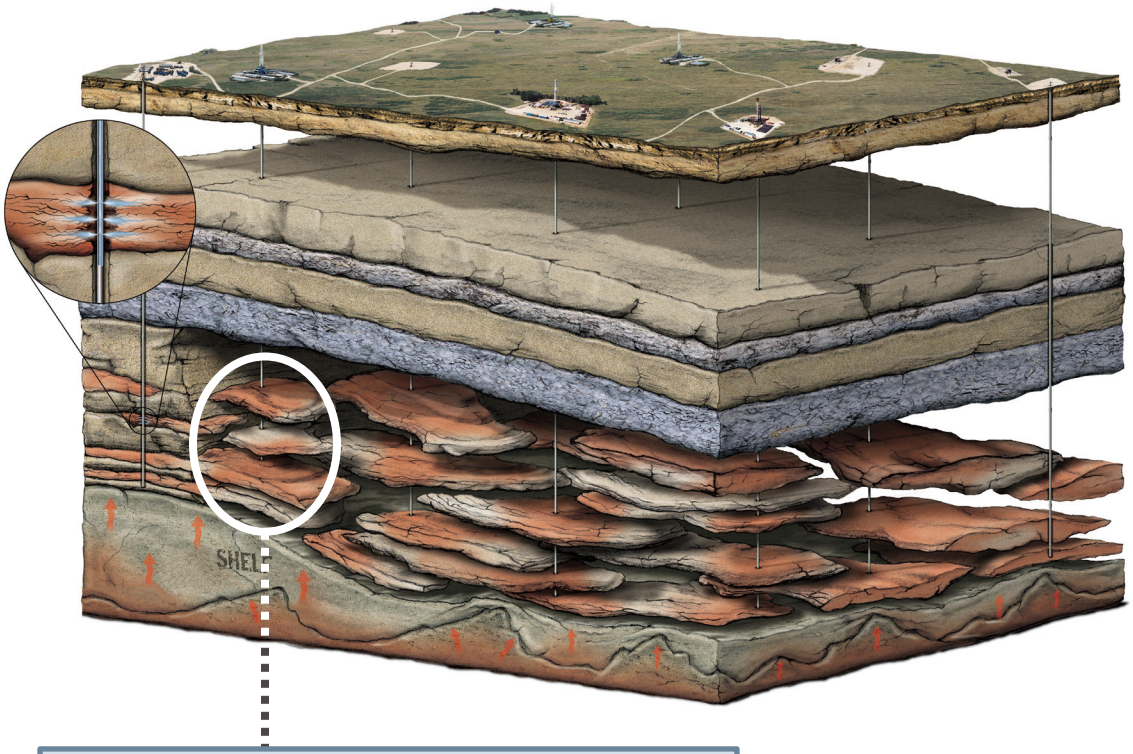
IRR % at $/BO WTI[(1)]





(1) Natural gas reflected at 18:1 to crude oil for price; 6:1 for rate

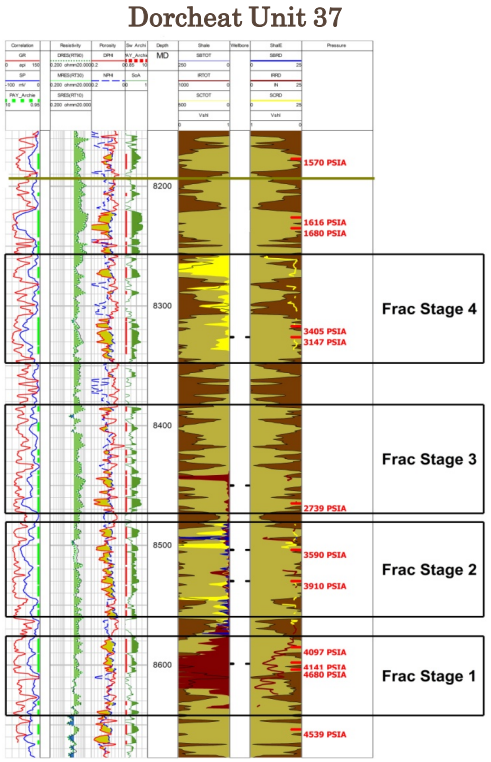
Cotton Valley Lenticular Oil Sands



- 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



Financial Overview

2012 Guidance

Production	Total:	3,175 - 3,650 Mboe
	Average Net Daily Production:	8,700 - 10,000 Boe/d
	Percent Oil & NGLs:	69%
Operating Costs and Expenses (per Boe)	Lease Operating:	$7.20 - $8.20
	Severance and Ad Valorem:	$3.60 - $4.00
	General and Administrative:	$5.75 - $6.25
Capital Expenditures	$250 million	
Rocky Mountain (Wattenberg Field)	$146 million	
Mid-Continent (Upstream)	$56 million	
Mid-Continent (Gas Processing Facilities)	$20 million	
Other (North Park Basin, Recompletions, Leasing)	$28 million	

Capitalization & Liquidity

Borrowing Base	$245 Million
Outstanding at March 31, 2012	$21.6 Million
Liquidity	$223 Million

Hedge Positions[1]

Commodity & Contract Term	Type	Avg. Volume	Floor	Ceiling	Avg. Price
Crude Oil		(Bo/Month)			
July – December 2012	collar	77,956	$ 90.00	$ 106.05	
January – April 2013	collar	42,654	$ 91.64	$ 112.00	
May – December 2013	collar	30,000	$ 92.33	$ 107.37	
July – December 2012	swap	29,576			$ 85.21
January – October 2013[2]	swap	17,542			$ 79.46
November – December 2013	swap	10,000			$ 93.00
Natural Gas		(MMBTU/Month)			
July – December 2012[2]	swap	16,713	$ -	$ -	$ 6.75
January – October 2013[2]	swap	15,481	$ -	$ -	$ 6.40

- 60% of current oil production hedged

(1) Hedge positions as of 7/01/2012

(2) Legacy hedges acquired in connection with Arkansas properties

Buying High Growth & Experience

- Highest company leverage to Wattenberg Niobrara
- Oil & liquids focused; 100% production growth in 2012
- Proven management team
- Strong balance sheet – considerable cash flow and credit resources

Bonanza Creek is Well Positioned for Continued Growth and Delivering Exceptional Returns

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:	$657 MM
52 Week Range:	$12.39 / $22.33
Shares Outstanding:	39.48 MM

Financial Auditor

Hein & Associates LLP

Reserve Auditor

Cawley, Gillespie and Associates, Inc.

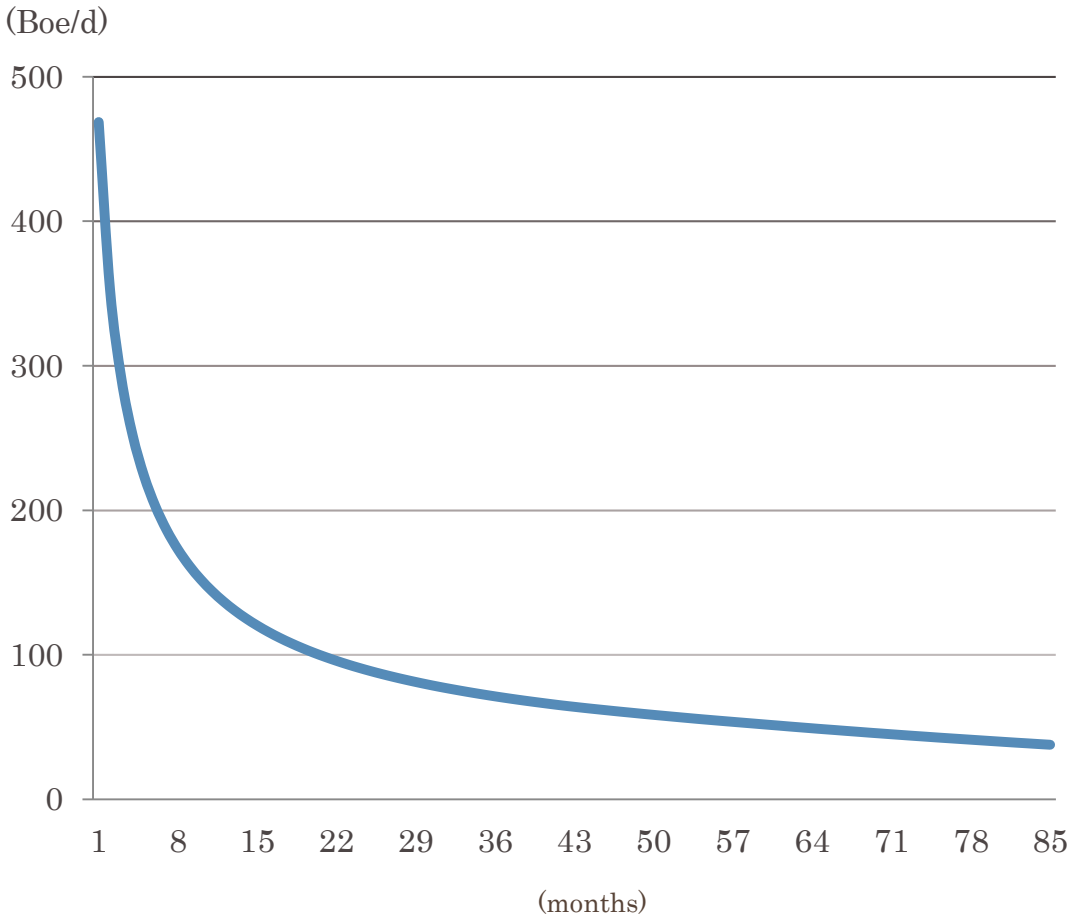
www.bonanzacrk.com

Appendix

Experienced Management Team

Mike Starzer *President & CEO* *27 Years*	• 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* *29 Years*	• 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
Jim Casperson *EVP & CFO* *30+ Years*	• Joined the Company in April 2011 as an independent Board member and Chairman of the Audit and Reserves Committees. CFO since October 2011 • Prior: CFO at Whiting Petroleum Corp (NYSE: WLL) • BBA in Accounting, Texas Tech University
Pat Graham *EVP – Corporate Development* *25 Years*	• 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

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

- 42,218 gross (29,262 net) acres
- 85.6% WI / 69.1% NRI
- 290 net locations at 80 acre spacing

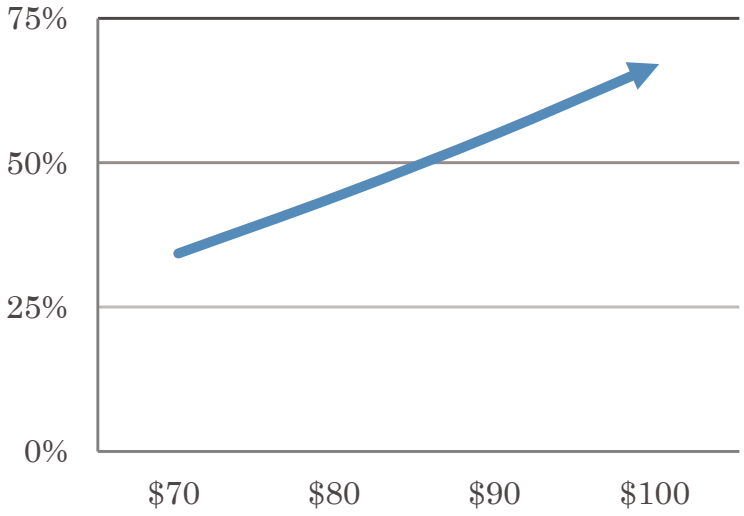
(1) Natural gas reflected at 18:1 to crude oil for price; 6:1 for rate

Wattenberg Vertical Niobrara/Codell Development

Economics

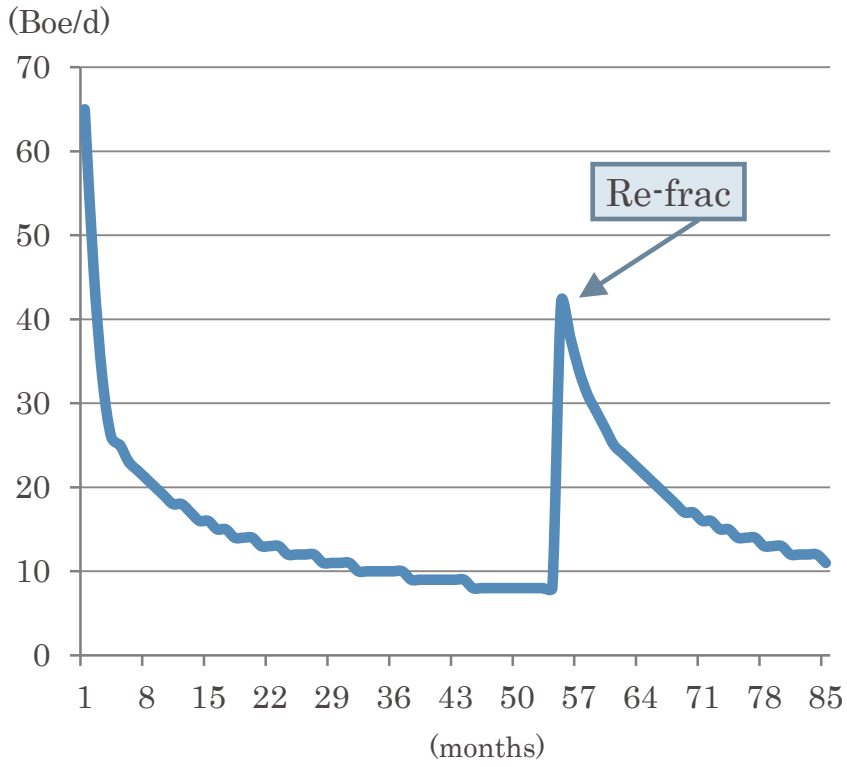
- $955,000 CapEx
  - $725,000 initial well cost
  - $230,000 refrac in five years
- <6 days D&C
- NPV_{10} at $80 / Bbl: $900,000
- NPV_{10} at $100 / Bbl: $1.4 million
- 219 gross PUD locations(2)
- 80.6% WI / 68.1% NRI

IRR % at $/BO WTI(1)



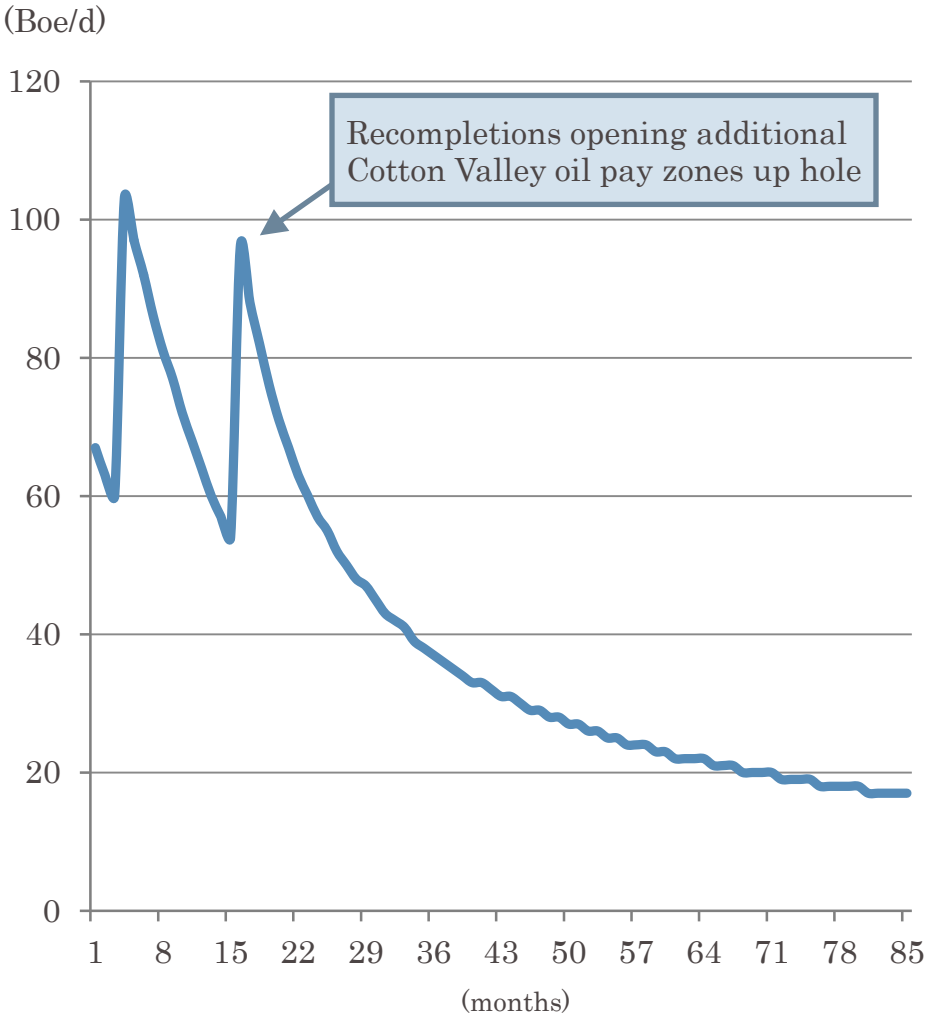
Type Curve(1)

- 78,000 Boe EUR
- 65 Boe/d initial 30-day rate
- Re-frac after 5 years with peak rate ~70% of IP rate



(1) Natural gas reflected at 18:1 to crude oil for price; 6:1 for rate
(2) PUD locations as of December 31, 2011

Dorcheat-Macedonia Field



Type Curve(1)

- 152,000 Boe EUR(2)
- 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
- $1.7 million CapEx, including two recompletions
- 12 days to drill; 3 days to complete

(1) Natural gas reflected at 18:1 to crude oil for price; 6:1 for rate

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

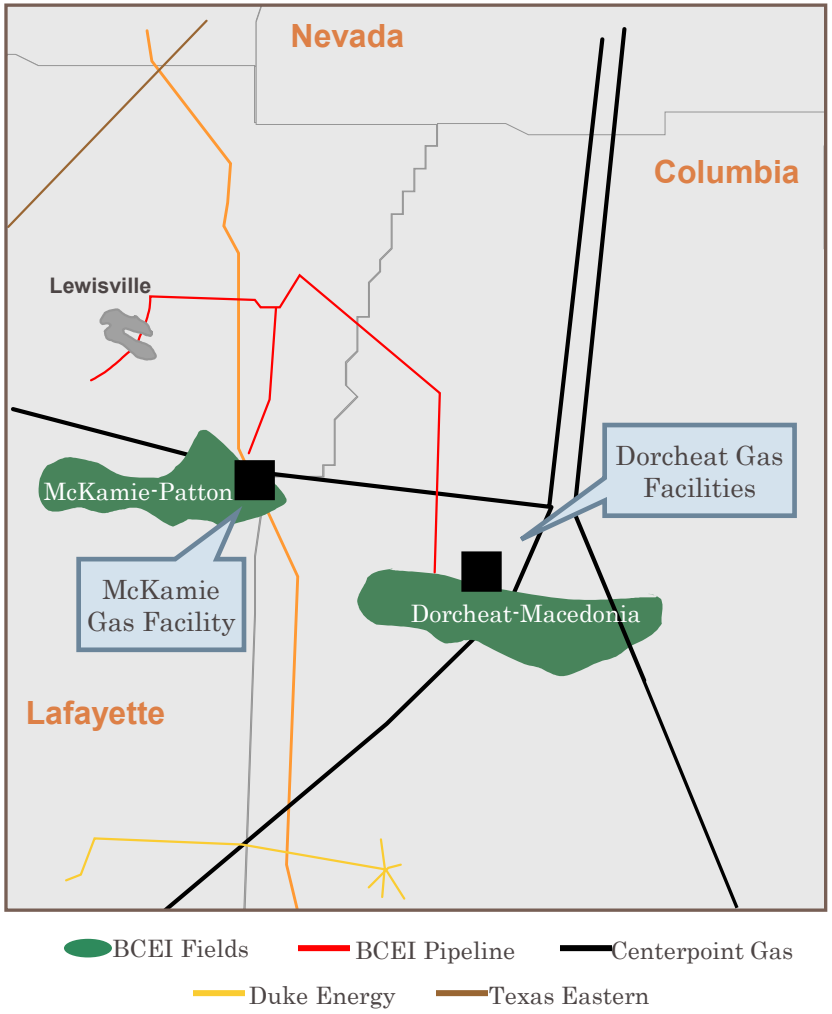
- 12.5 MMcf/d of natural gas (28,000 gallons per day of natural gas liquids) processing capacity
- Additional 12.5 MMcf/d of capacity to be on line in January 2013. Expansion at current Dorcheat site

McKamie Gas Processing Facility

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

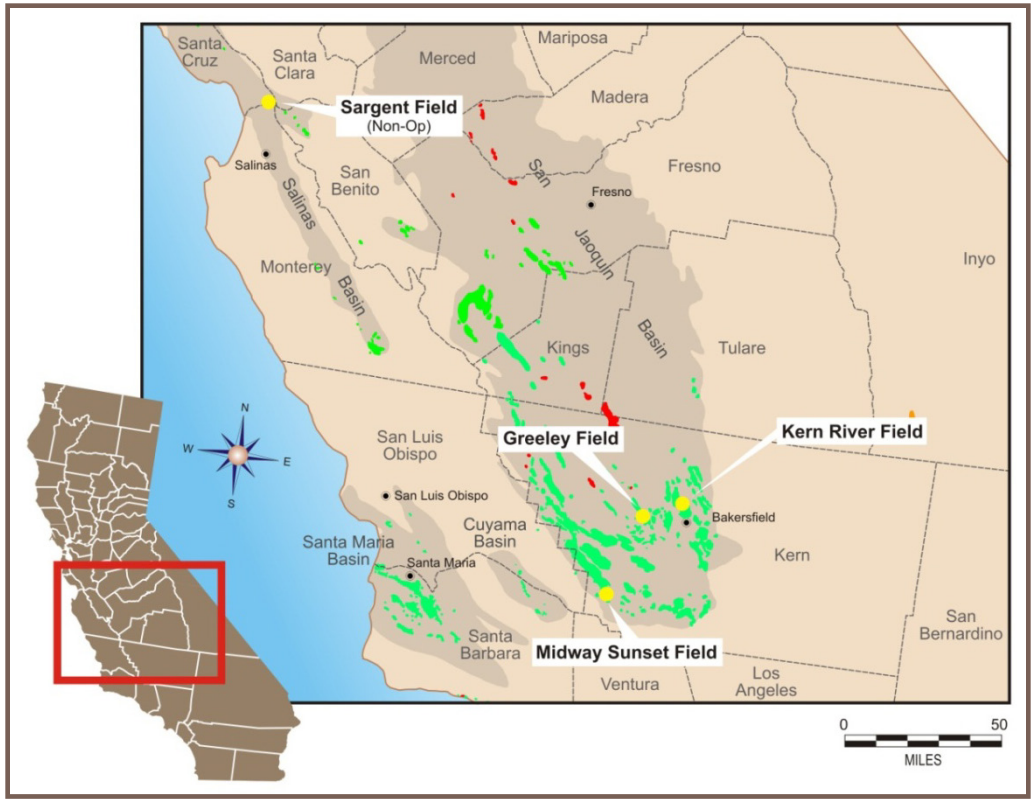
Gas Facilities Enhance Total Returns

- 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



California Region

- 8,940 gross (5,012 net) acres
  - 100% HBP
- Thermal development opportunity in Kern River and Midway Sunset
  - 16.5 MMBoe original oil in place(1)
- 0.7 MMBoe of Proved Reserves
  - 100% crude oil
  - 37% developed
- Operate 41 gross producing wells
  - 13 gross non-operated



(1) Original oil in place is not an indication of the quantity of oil that is likely to be produced, but is an indication of the estimated size of the reservoir

Reconciliation to EBITDAX

We define EBITDAX as net income, plus (1) exploration expense, (2) lease rentals, (3) depletion, depreciation and amortization expense, (4) stock-based compensation expense, (5) interest expense, (6) other income (loss), (7) unrealized loss (gain) on commodity derivatives and (8) 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 months ended March 31, 2012 and 2011 (in thousands, except per-share amounts).

	For the three months ended March 31,	
	2012	2011
Net Income	$ 8,546	$ 327
Exploration	1,201	525
Depletion, depreciation, and amortization	11,828	6,387
Stock-based compensation	671	-
Interest expense	562	713
Unrealized loss (gain) on commodity derivatives	3,376	5,455
Income taxes (benefit)	5,350	192
EBITDAX	$ 31,534	$ 13,599
EBITDAX per diluted share	$ 0.80	$ 0.47
Weighted average number of common stock – basic and diluted	39,478	29,123