FOCUSED ON VALUE DELIVERING GROWTH

ANALYST DAY

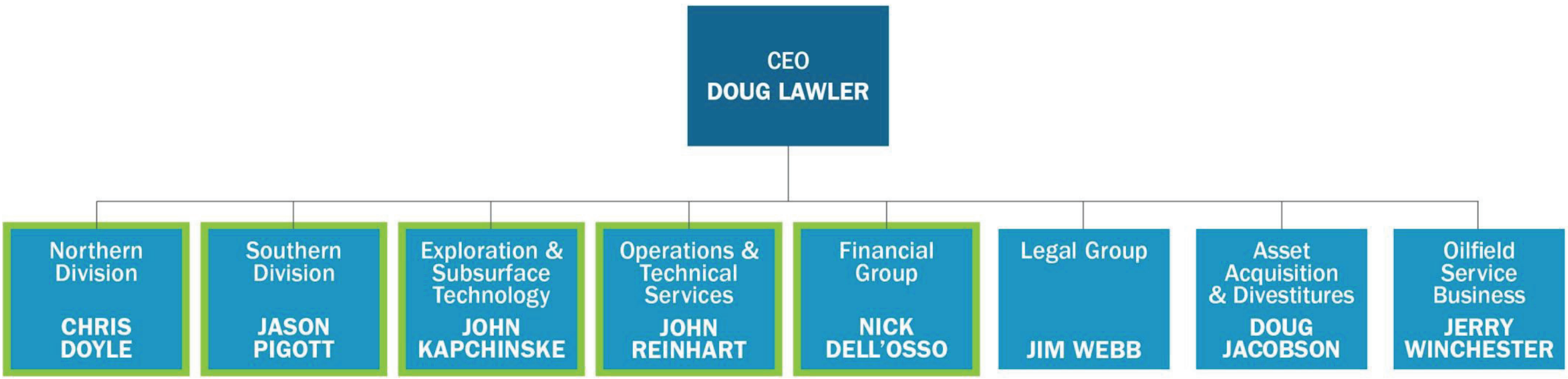
May 16, 2014 I Oklahoma City, Oklahoma

Chesapeake ENERGY

FORWARD-LOOKING STATEMENTS

- These presentations include “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements other than those of historical fact that give our current expectations or forecasts of future events. They include production forecasts, estimates of operating costs, assumptions regarding future natural gas and liquids prices, planned drilling activity, estimated future capital expenditures, and estimates of recoverable resources, as well as projected cash flow, business strategy and other plans and objectives for future operations. Although we believe the expectations and forecasts reflected in forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate or changed assumptions or by known or unknown risks and uncertainties.
- Factors that could cause actual results to differ materially from expected results are described under “Risk Factors” in Item 1A of our 2013 annual report on Form 10-K filed with the U.S. Securities and Exchange Commission on February 27, 2014. These risk factors include the volatility of natural gas, oil and NGL prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the prices of natural gas and oil potentially resulting in a write-down of our asset carrying values; the availability of capital on an economic basis, including through planned asset sales, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures; our ability to generate profits or achieve targeted results in drilling and well operations; leasehold terms expiring before production can be established; hedging activities resulting in lower prices realized on natural gas, oil and NGL sales; the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations; drilling and operating risks, including potential environmental liabilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing, air emissions and endangered species; a deterioration in general economic, business or industry conditions having a material adverse effect on our results of operations, liquidity and financial condition; oilfield services shortages, gathering system and transportation capacity constraints and various transportation interruptions that could adversely affect our revenues and cash flow; adverse developments and losses in connection with pending or future litigation and regulatory investigations; cyber attacks adversely impacting our operations; and an interruption at our headquarters that adversely affects our business.
- Disclosures concerning the estimated contribution of derivative contracts to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. References to “EUR” (estimated ultimate recovery) and “resources” include estimates of quantities of natural gas, oil and NGL we believe will ultimately be produced, but that are not yet classified as “proved reserves”, as defined in SEC regulations. Further, these terms are broader descriptions of potentially recoverable volumes than SEC definitions of “probable” or “possible” reserves. Estimates of such unproved resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.
- The timing of and amount of proceeds from future asset sales, which are subject to changes in market conditions and other factors beyond our control, will affect our ability to further reduce financial leverage and complexity. There can be no assurance that the spin-off of our oilfield services business will be consummated. It is subject to satisfaction of several conditions, some of which are beyond our control, including market conditions, board approval and regulatory review and approvals, among others.
- We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this presentation or as otherwise indicated, and we undertake no obligation to update this information, except as required by applicable law.

ORGANIZATIONAL STRUCTURE



AGENDA

7:00 am	Registration and Breakfast
7:30 am	Gary Clark: Welcome and Agenda Overview
7:35 am	Doug Lawler: Company Overview
8:15 am	Nick Dell'Osso: Financial Overview and Q&A
9:00 am	John Reinhart: Capital Efficiency and Technical Services
9:30 am	Jason Pigott: Southern Division
10:15 am	Break
10:30 am	Chris Doyle: Northern Division
11:15 am	John Kapchinske: Exploration and Subsurface Technology
11:45 pm	Doug Lawler: Unlocking Value and Q&A
12:15 - 2:00 pm	Lunch, Poster Board Sessions & RTC Tours

COMPANY OVERVIEW

DOUG LAWLER
PRESIDENT, CHIEF EXECUTIVE OFFICER AND DIRECTOR

FOUNDATIONAL ELEMENTS FOR VALUE CREATION

BUSINESS TRANSFORMATION OVERVIEW

- Organizational structure
- Capital efficiency improvement
- Cash cost reduction
- Corporate budget process and plan
- Portfolio management and capital allocation process
- Performance measurement and compensation program

APPLYING OUR BUSINESS STRATEGIES

FINANCIAL DISCIPLINE

- Balance capital expenditures with cash flow from operations
- Divest noncore assets and noncore affiliates
- Reduce financial and operational risk and complexity
- Achieve investment grade metrics

PROFITABLE AND EFFICIENT GROWTH FROM CAPTURED RESOURCES

- Develop world-class inventory
- Target top-quartile operating and financial metrics
- Pursue continuous improvement
- Drive value leakage out of operations

YARDSTICK TO MEASURE CHK

RISK & RETURN

- Total shareholder return
- Adjusted ROCE
- Adjusted ROE
- Debt/proved reserve base

GROWTH

- Operating cash flow growth/ debt-adjusted share
- Production growth/ debt-adjusted share
- Reserve growth/ debt-adjusted share

OPERATIONAL EFFICIENCY

- Realized price/boe
- Production expense/boe
- G&A/boe
- Operating margin/boe
- F&D costs/boe
- Reinvestment ratio

COMPENSATION IS ALIGNED WITH STRATEGIC GOALS AND METRICS

PRODUCTION GROWTH ▪ Increase Liquids Production ▪ Grow Production and Reduce Downtime

EBITDA/BOE ▪ Aggressively Manage Expenses ▪ Deliver Shareholder Return ▪ Assess and Optimize Portfolio

TRIR AND REPORTABLE SPILLS ▪ Protect People ▪ Protect the Environment ▪ Protect the Company

CAPITAL EXPENDITURES ▪ Decrease Well Costs ▪ Drive Ownership and Accountability

RESERVE GROWTH ▪ Develop World-Class Inventory

2014 FULL YEAR OUTLOOK UPDATE

	Adjusted Total Production Growth	Operating Cash Flow ($mm)(2)(3)	Total Capital Expenditures ($mm)
Prior Outlook - 5/7/14	9 – 12%	$5,800 – $6,000	$5,200 – $5,600
Current Outlook - 5/16/14	9 – 12%(1)	$5,550 – $5,750	$5,000 – $5,400

(1) Growth range based on 2013 production of 600 mboe/day adjusted for projected asset sales as provided in Chesapeake's 5/16/14 Outlook.
(2) A non-GAAP financial measure. We are unable to provide reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities.
(3) Assumes NYMEX prices on open contracts of $4.50 per mcf and $95.00 per bbl and production growth ranges as shown above.

Chesapeake ENERGY

FINANCIAL OVERVIEW

NICK DELL'OSSO
EXECUTIVE VICE PRESIDENT & CHIEF FINANCIAL OFFICER

MAXIMIZING SHAREHOLDER VALUE

- Delivering cash flow growth with balanced spending
- Competitive capital allocation
- Optimizing capital structure
- Reducing complexity and obligations
- Increasing cash flow certainty

FINANCIAL STRATEGY
FOCUSED
ON GROWING
EQUITY VALUE

1Q'14 FINANCIAL RESULTS

ADJ. EARNINGS/FDS

97% YOY

$0.59

ADJ. EBITDA

34% YOY

$1.5 billion

PROD. and G&A EXP.

12% YOY

$5.83/boe(1)

LIQUIDITY

$5.0 billion(2)

YTD ASSET SALES

$925 million(3)

TOTAL CAPEX

53% YOY

$850 million

(1) G&A excludes expenses associated with share-based compensation and restructuring and other termination costs
(2) Includes unrestricted cash and borrowing availability under revolving credit facilities as of 3/31/2014
(3) Includes $362 mm for compression assets sold to Exterran Partners, $209 mm for Chaparral Energy common equity, $159 mm for compression units sold to Access Midstream Partners, and $195 mm for real estate and other miscellaneous noncore assets

Note: Reconciliations of non-GAAP measures to comparable GAAP measures appear on pages 20-21

1Q'14 OPERATIONAL RESULTS

› TOTAL ADJ. PROD.[1]

11% YOY

675.2 mboe/d

› LIQUIDS MIX [2]

to 29% of Total Production

24% in 1Q'13

› ADJ. OIL PROD.[1]

20% YOY

109.5 mbbls/d

› ADJ. NGL PROD.[1]

63% YOY

84.2 mbbls/d

› ADJ. NATURAL GAS [1]

4% YOY

2.9 bcf/d

(1) Adjusted for 2013 asset sales
(2) Oil and NGL collectively referred to as "liquids"

Chesapeake ENERGY

EXPECTED ASSET DIVESTITURES DRIVE DE-LEVERING

We continue to sell noncore assets and focus our resources on highest return opportunities while reducing leverage and complexity

Oilfield services

- Pursuing tax-free spin
- $1.1 billion consolidated debt reduction
- ~$400 million applied to repay intercompany debt

Noncore producing asset sales

- CHK Cleveland Tonkawa, L.L.C., East Texas, South Texas and SW Oklahoma
- $1.0 billion reduction in subsidiary preferred (NCI) and elimination of ~$160 million ORRI obligation (long-term liability)
- $225 million of aggregate expected net cash proceeds
- VPPs #5 and #6 will transfer with South Texas and East Texas assets

Noncore acreage sales

- Southwest PA and Northern PRB
- $290 million of aggregate expected cash proceeds from the sale of 28,000 acres

$4.0B
Anticipated 2014 Asset Divestitures

Chesapeake ENERGY

PRO FORMA IMPACT OF EXPECTED ASSET DIVESTITURES

Asset Divestitures ($ mm)[1]	COS Spin-Off	Noncore Producing Assets	Noncore Acreage	Total	Reduction[2]
Capitalization Impact					
Debt/preferred reduction	$1,115	$1,015	$-	$2,130	
Cash proceeds, net	$400	$225	$290	$915	
Total				$3,045	20%
2014 Outlook Impacts					
Production (mmboe)	N/A	(5)	-	(5)	2%
Operating cash flow[3]	$(80)	$(160)	$(10)	$(250)	4%
Capital expenditures	$(30)	$(170)	$ -	$(200)	4%
Interest & dividend	$(30)	$(40)	$ -	$(70)	5%

Expected net debt & preferred (NCI) reduction of 20% while production and operating cash flow decline only 2% and 4%, respectively

(1) See page 5 for description of expected asset divestitures
(2) Reduction compared to 3/31/14 net debt and NCI and midpoint of Outlook issued on 5/7/14
(3) A non-GAAP financial measure. We are unable to provide reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities

REDUCING OBLIGATIONS AND COMPLEXITY

($mm)	12/31/12	12/31/13	3/31/14	12/31/14E
Term Loan	$2,000	$2,000	$0	$0
Long-Term Bonds	$10,666	$10,838	$12,475	$11,825
Credit Facilities	$418	$405	$464	$0
Total Debt	$13,084	$13,243	$12,939	$11,825

~10% reduction

VPPs	$3,187	$2,455	$2,310	$1,720
Operating & Finance Leases	$1,255	$814	$376	$182
Subsidiary Preferred	$2,500	$2,310	$2,310	$1,060
Corporate Preferred	$1,531	$1,531	$1,531	$1,531
Cash	($287)	($837)	($1,005)	($1,200)
Total Adjusted Net Leverage	$21,270	$19,516	$18,461	$15,118

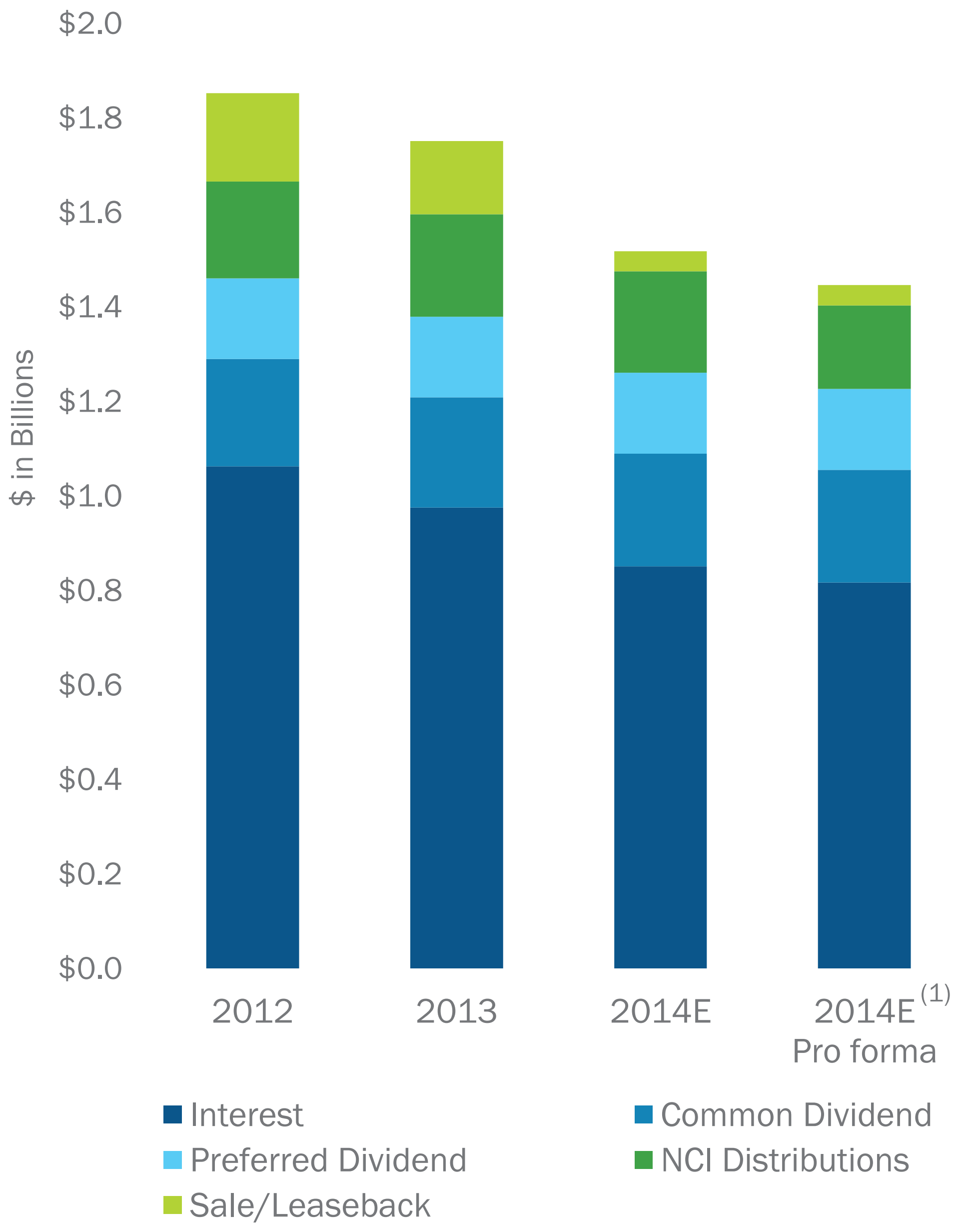
~30% reduction

$6.2B
Reduction in Leverage During the Past 2 years

Note: See page 19 for explanation of adjustments and assumptions

Chesapeake ENERGY

ANNUAL FINANCING COSTS ARE FALLING



- >20% reduction since YE'12
- Weighted average cost of debt reduced from 5.9% to 5.1%

$250 MM savings

Annual decrease in cash interest/dividends from April 2014 debt refinancing, COS spin-off and CT divestment

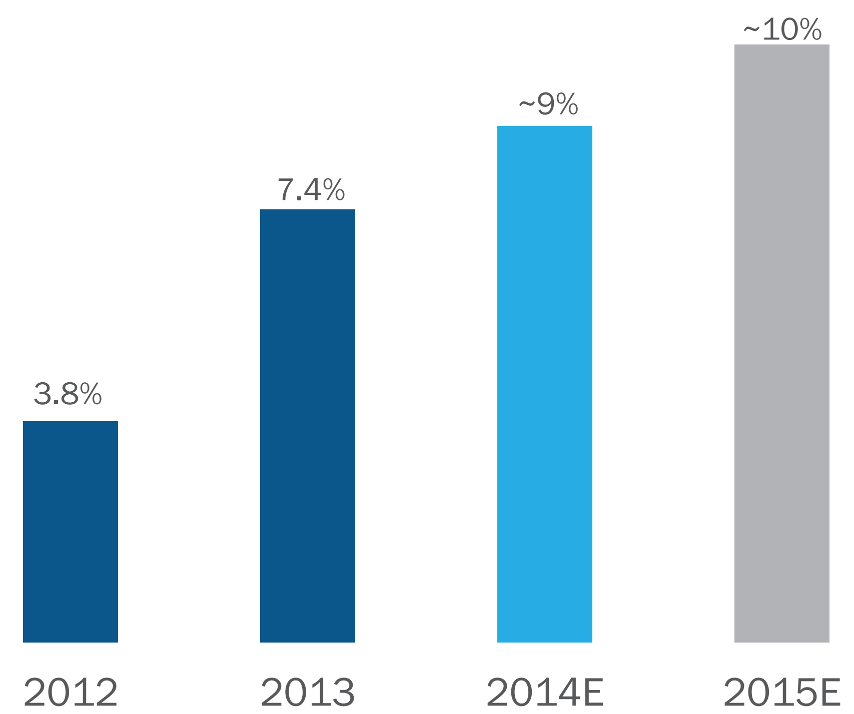
(1) Assumes spin-off of Chesapeake Oilfield Services, sale of noncore producing assets, and sale of noncore acreage announced on 5/21/14

Chesapeake ENERGY

CAPITAL ALLOCATION

- Enhanced returns with competitive capital allocation
- Capital shift to higher-margin, higher-return programs
- Cost structure and efficiency remains a focus area
- 95% of capital allocation is value driven vs. commitment driven

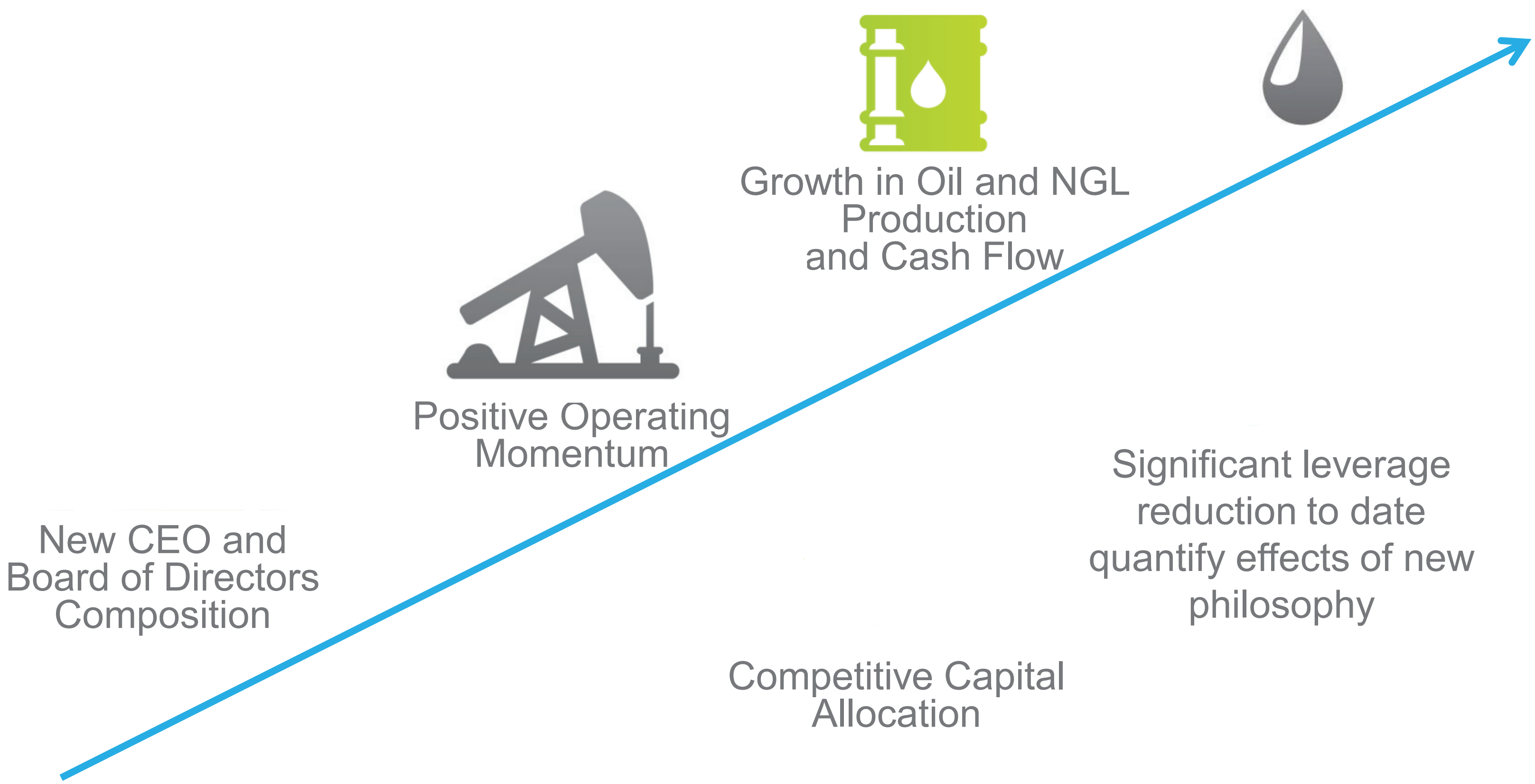
Return on Capital Employed (ROCE)(1)



(1) Average NYMEX prices on open contracts of $4.50/mcf and $95.00/bbl in 2014 and $4.00/mcf and $90.00/bbl in 2015 using the midpoints of the 2014 Outlook and 2015 preview, respectively

DRIVING TOWARDS INVESTMENT GRADE

- **Changes in Management, Governance and Financial Policies**
- **Positive Operating Momentum**
- **Credible Actions to Back Up New Philosophy**



Chesapeake ENERGY

FINANCIAL OVERVIEW

APPENDIX

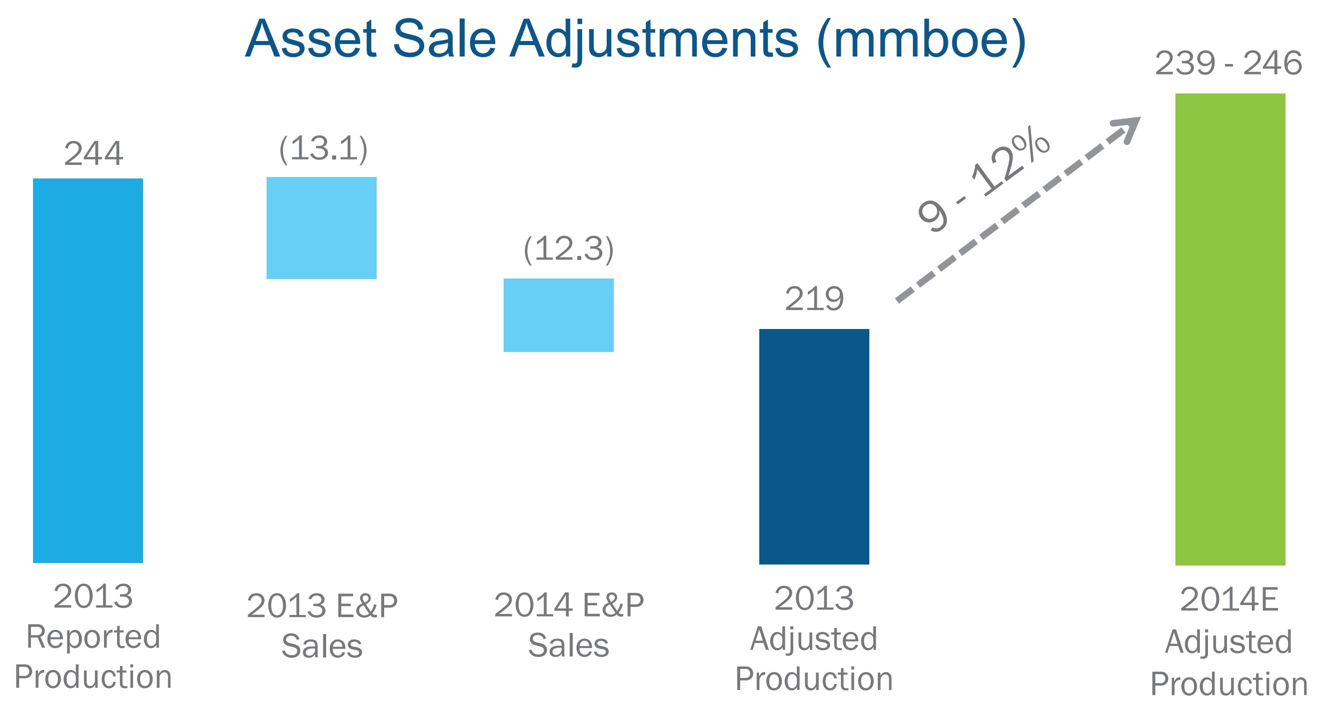
PRO FORMA 2014 OUTLOOK

	5/7/14 Outlook	COS Spin-off	E&P Asset Sales	5/16/14 Outlook
Adjusted Production Growth[1]:				
Liquids	25% - 29%		4%	29% - 33%
Oil	8% -12%		3%	11% - 15%
NGL[2]	58% -63%		5%	63% - 68%
Natural Gas	4% -6%		0%	4% - 6%
Total Adjusted Production	9% -12%		0%	9% - 12%
Daily rate (mboe)	690 -710		(15)	675 - 695
Subsidiary Margins[6]	250 - 325	(120)	0	130 - 205
Net Income Attributable to NCI and Other[7]	(160) - (190)	0	40	(120) - (150)
Operating Cash Flow ($MM)[3][4]	5,800 - 6,000	(80)	(170)	5,550 - 5,750
Total Capital Expenditures ($MM)	5,200 - 5,600	(30)	(170)	5,000 - 5,400
Interest[5], Dividends and Distributions	1,340 - 1,420	(30)	(40)	1,270 - 1,350

(1) Growth ranges based on 2013 production of 600mboe/day adjusted for projected asset sales as provided in 5/16/14 Outlook
(2) Assumes ethane recovery in Utica and southern Marcellus to fulfill CHK's pipeline commitments, no ethane recovery in Rockies, minimal ethane recovery in Eagle Ford and partial ethane recovery in Mid-Continent
(3) Assumes average NYMEX prices on open contracts of $4.50/mcf and $95.00/bbl in 2014
(4) A non-GAAP financial measure. We are unable to provide reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities
(5) Includes interest expense and capitalized interest
(6) Includes revenue and operating costs and excludes depreciation and amortization of other assets
(7) Net income attributable to noncontrolling interest of CHKR, CHK Utica, L.L.C and CHK Cleveland Tonkawa, L.L.C

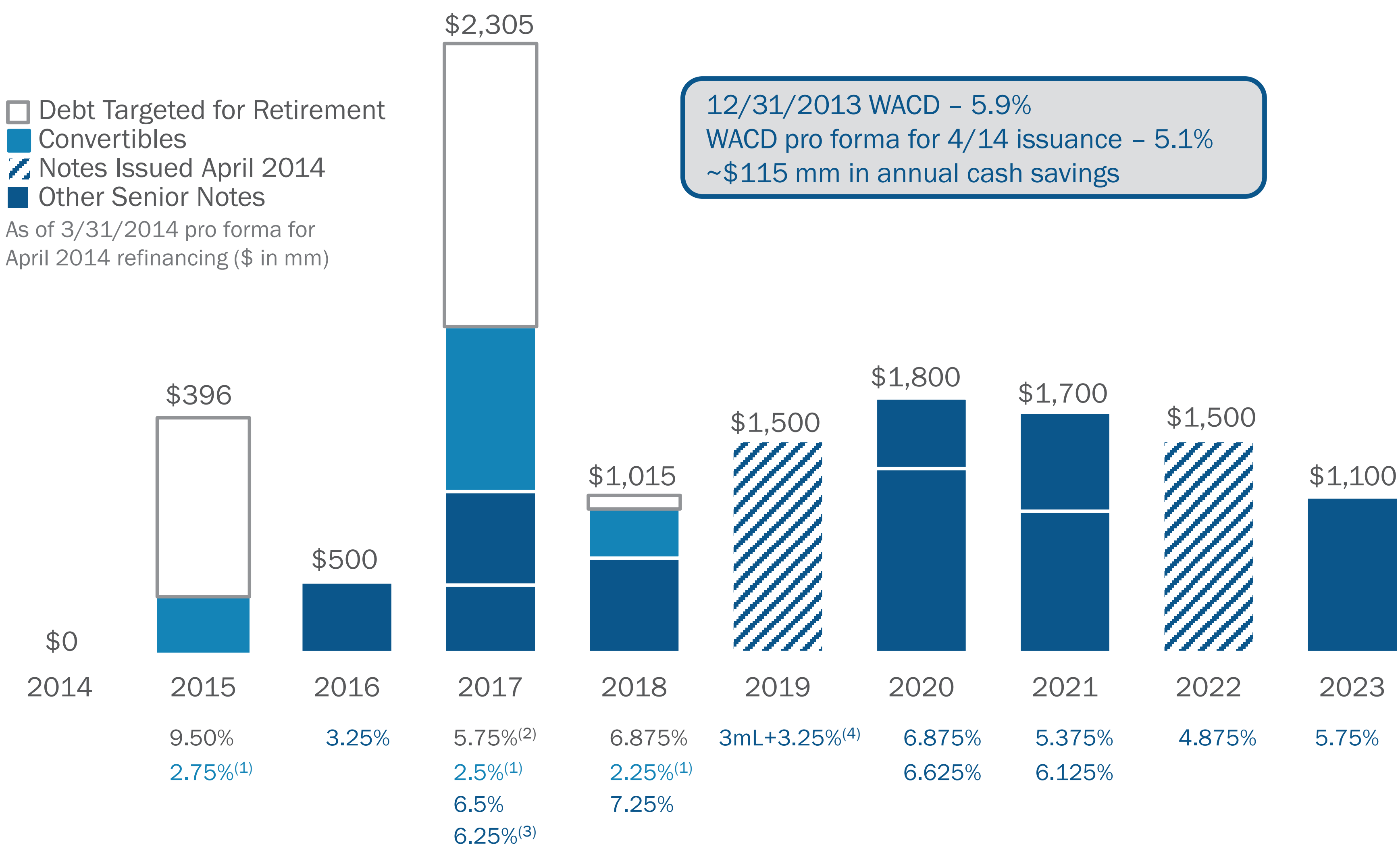
Chesapeake ENERGY

ADJUSTED PRODUCTION GROWTH



	2013 Reported Production	E&P Sales	2013 Adjusted Production	2014E Adjusted Production Growth
Oil (mmbbls)	41.1	(6.3)	34.8	11 – 15%
NGL (mmbbls)	20.9	(2.0)	18.9	63 – 68%
Natural Gas (bcf)	1,095	(103)	992	4 – 6%
Total (mmboe)	244.4	(25.4)	219	9 – 12%

SENIOR NOTE PROFILE



(1) Recognizes earliest investor put option as maturity for the 2.75% 2035, 2.5% 2037 and 2.25% 2038 Contingent Convertible Senior Notes
(2) Term loan; Interest at LIBOR plus 4.50%; LIBOR rate is subject to a floor of 1.25% per annum
(3) Euro-denominated notes with a principal amount based on the exchange rate of $1.3855 to €1.00 at 4/9/2014
(4) All-in yield composed of 3.25% spread and 3mL

10K/Q COMMITMENTS

($ mm)	12/31/2012	12/31/2013	3/31/2014
Chesapeake commitments			
Compressor leases	$405	$260	$63
Rig leases	$307	$76	$20
Drilling contracts	$202	$41	$109
Other operating leases	$56	$39	$35
Investments	$90	-	-
Net acreage maintenance	$26	$28	$28
CEMI commitments			
G/T and processing	$18,490	$17,190	$16,734
Oilfield Services			
Property and equipment	$118	$30	$117
Operational (wells to drill)			
Utica JV			52 gross by 7/31/15
CHK Utica			47 net by 12/31/16
CHK C-T			137 net by 13/21/16
CHKR - Granite Wash			29 net by 6/30/16

SUMMARY OF MIDSTREAM AND MARKETING COMMITMENTS AS OF 3/31/14

Dollar commitments ($mm)	2014	2015	2016	2017	2018	2019	Thereafter	Total
NGL transportation	$55	$96	$118	$139	$171	$171	$1,464	$2,214
Oil transportation	$138	$207	$226	$260	$250	$257	$895	$2,233
Processing/treating	$165	$229	$232	$234	$238	$242	$456	$1,796
Other gas gathering	$263	$4	$4	$3	$2	$2	$0	$278
Haynesville gathering	$105	$176	$213	$195	$0	$0	$0	$689
Haynesville transportation	$115	$150	$150	$150	$148	$140	$735	$1,588
Barnett gathering	$275	$392	$409	$426	$414	$203	$9	$2,128
Barnett transportation	$170	$221	$219	$211	$201	$137	$105	$1,264
Other commitments	$260	$355	$344	$330	$325	$310	$2,620	$4,544
Total	$1,546	$1,830	$1,915	$1,948	$1,749	$1,462	$6,284	$16,734

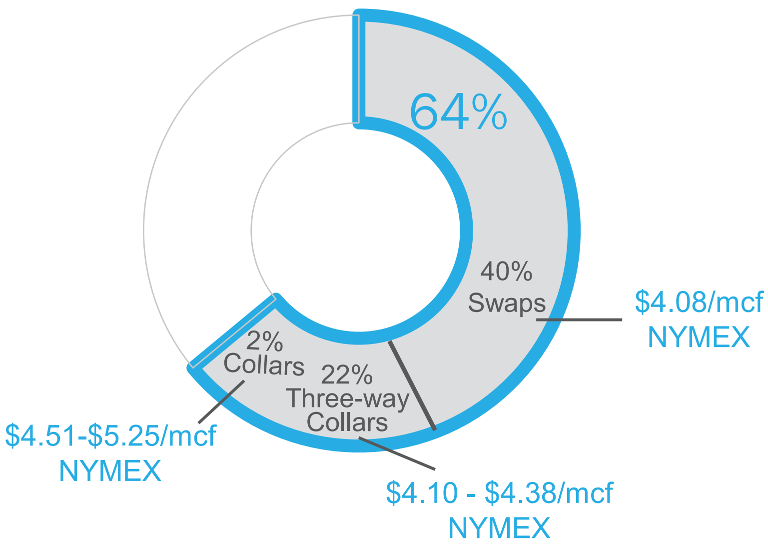
Minimum volume commitments(1)	2014	2015	2016	2017	2018	2019	Thereafter	Total
Haynesville (mmcf)	820	1,020	1,200	1,070	-	-	-	
Barnett (mmcf)	960	1,000	1,020	1,045	1,055	1,000	-	

(1) Data represents Chesapeake marketed volumes.
Note: please refer to 10k/10Q for additional details

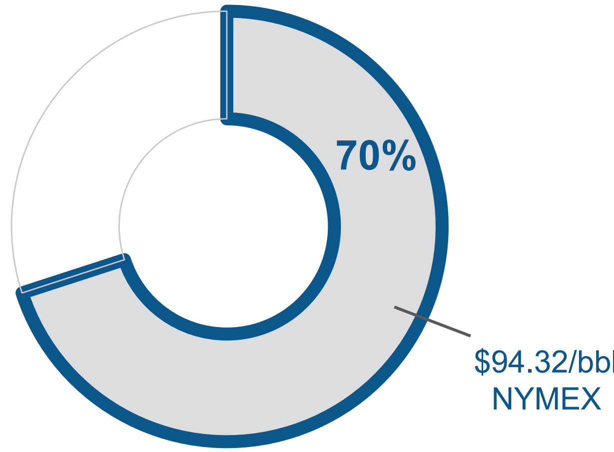
Chesapeake ENERGY

CHK'S HEDGING STRATEGY INCREASES CASH FLOW CERTAINTY IN 2014

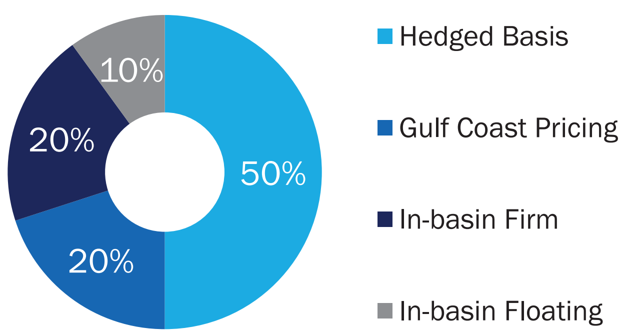
Natural Gas



Oil



% of Total 2014 Northeast Natural Gas Hedged



- Ensures delivery of business strategy by securing prices
- Proactively managing basis

REDUCING OBLIGATIONS AND COMPLEXITY

	12/31/12	12/31/13	3/31/14(1)	12/31/14E(2)
Term Loan	$2,000	$2,000	$0	$0
Long-Term Bonds(3)	$10,666	$10,838	$12,475	$11,825
Credit Facilities	$418	$405	$464	$0
Total Debt	$13,084	$13,243	$12,939	$11,825
	10% reduction			
VPPs	$3,187	$2,455	$2,310	$1,720
Operating & Finance Leases	$1,255	$814	$376	$182
Subsidiary Preferred	$2,500	$2,310	$2,310	$1,060
Corporate Preferred	$1,531	$1,531	$1,531	$1,531
Cash	($287)	($837)	($1,005)	($1,200)
Total Adjusted Net Leverage(4)	$21,270	$19,516	$18,461	$15,118
	30% reduction			
Total Adjusted Net Leverage/Adjusted EBITDA(5)	4.4	3.4	3.4	2.8
Total Adjusted Net Leverage/PD Reserves (MMBOE)	$13.23	$10.29	$9.22	$6.99
Adjusted EBITDA/Adjusted Interest(5)	3.7	4.6	5.0	5.8

- Senior Note Refinancing completed in April and May 2014
- Credit Facility
  - > Fully available to supplement working capital or provide short term funding needs
- Reducing Complexity
  - > Reduction in operating leases
  - > Negotiating to sell the C/T assets
  - > VPPs do not impact our operational decision making

1) Pro forma to reflect the early tender on the 9.5% senior notes due 2015, the redemption of the 6.875% senior notes due 2018, and the issuance of $1.5B of floating rate notes due 2019 and $1.5B of 4.875% senior notes due 2022
2) Assumes spin-off of Chesapeake Oilfield Services, sale of noncore producing assets, and sale of noncore acreage during Q2 2014
3) Excludes discount on senior notes and includes interest rate derivatives
4) Total Adjusted Net Leverage reflects standard adjustments made to modify reported balance sheet debt for several off-balance sheet debt items (operating leases, corporate and subsidiary preferred, gross-up for discount on senior notes, and VPPs) in line with rating agency methodology. Adjusted made were largely based on Moody's methodology except Moody's no longer treats corporate preferred equity as debt
5) Adjusted EBITDA and Adjusted Interest include adjustments for capitalized interest, operating leases, corporate and subsidiary preferred, and VPPs based on Moody's methodology

Chesapeake ENERGY

RECONCILIATION

Three Months Ended:	3/31/2014	3/31/2013
	($ in mm, except per share data)	
Net income available to common stockholders	$374	$15
Adjustments, net of tax:		
Unrealized losses on derivatives	80	94
Restructuring and other termination costs	(4)	83
Impairments of fixed assets and other	12	16
Net gains on sales of fixed assets	(14)	(30)
Losses on investments	–	6
Net gains on sales of investments	(42)	–
Other	(1)	(1)
Adjusted net income available to common stockholders(1)	$405	$183
Preferred stock dividends	43	43
Earnings allocated to participating securities	8	–
Total adjusted net income attributable to CHK	$456	$226
Weighted average fully diluted shares outstanding(2)	767	761
Adjusted earnings per share assuming dilution(1)	$0.59	$0.30

(1) Adjusted net income available to common stockholders and adjusted earnings per share assuming dilution exclude certain items that management believes affect the comparability of operating results. The company believes these adjusted financial measures are a useful adjunct to earnings calculated in accordance with accounting principles generally accepted in the United States (GAAP) because:
(i) Management uses adjusted net income available to common stockholders to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
(ii) Adjusted net income available to common stockholders is more comparable to earnings estimates provided by securities analysts.
(iii) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

(2) In millions. Weighted average fully diluted shares outstanding include shares that were considered antidilutive for calculating earnings per share in accordance with GAAP

RECONCILIATION

Three Months Ended:	3/31/2014	3/31/2013
	($ in mm)	
Cash provided by operating activities	$1,291	$924
Changes in assets and liabilities	323	255
Operating cash flow[(1)]	$1,614	$1,179
Net income	$466	$102
Interest expense	39	21
Income tax expense	280	63
Depreciation and amortization of other assets	78	78
Natural gas, oil and NGL depreciation, depletion and amortization	628	648
EBITDA[(2)]	$1,491	$912
Adjustments:		
Unrealized losses on natural gas, oil and NGL derivatives	144	146
Restructuring and other termination costs	(7)	133
Impairments of fixed assets and other	20	27
Net gains on sales of fixed assets	(23)	(49)
Losses on investments	–	10
Net gains on sales of investments	(67)	–
Net income attributable to noncontrolling interests	(41)	(44)
Other	(2)	(1)
Adjusted EBITDA[(3)]	$1,515	$1,134

(1) Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under GAAP. Operating cash flow is widely accepted as a financial indicator of a natural gas and oil company's ability to generate cash which is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the natural gas and oil exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.

(2) Ebitda represents net income (loss) before interest expense, income taxes, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations or cash flow provided by operating activities prepared in accordance with GAAP.

(3) Adjusted ebitda excludes certain items that management believes affect the comparability of operating results. The company believes these non-GAAP financial measures are a useful adjunct to ebitda because:
- (i) Management uses adjusted ebitda to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
- (ii) Adjusted ebitda is more comparable to estimates provided by securities analysts.
- (iii) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

Chesapeake ENERGY

CAPITAL EFFICIENCY
& TECHNICAL SERVICES

JOHN REINHART
SVP - OPERATIONS &
TECHNICAL SERVICES

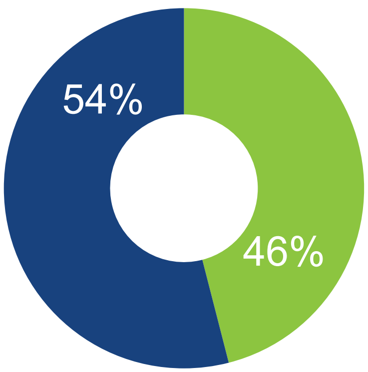
FOCUSED ON VALUE

- Previously focused on opportunity capture at very rapid pace
  - > HBP efforts were inefficient
- Refocus on value maximization
  - > Operational efficiencies
  - > Production acceleration
  - > Supply chain value

Value Maximization Focus

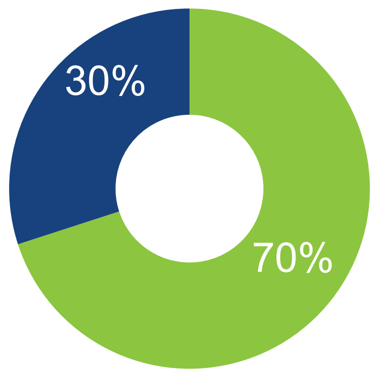
REALIZING IMPACT OF STRATEGY SHIFTS

2012



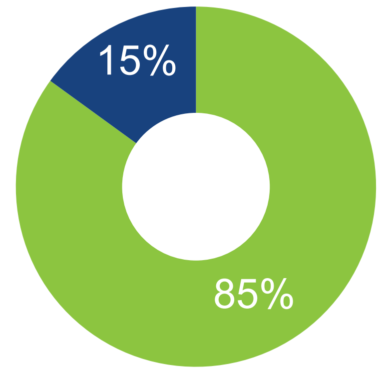
HBP Focus

2013



Pad Drilling Focus and Right-sized Drilling Program

1Q'14



Value Maximization Focus

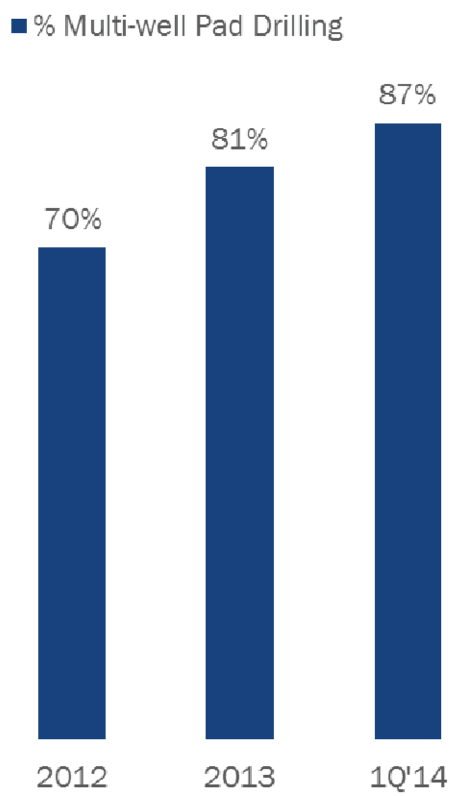
- Negative PV-10
- Positive PV-10

20%

Improvement of wells accretive to program NPV 1Q'14 vs. 2013

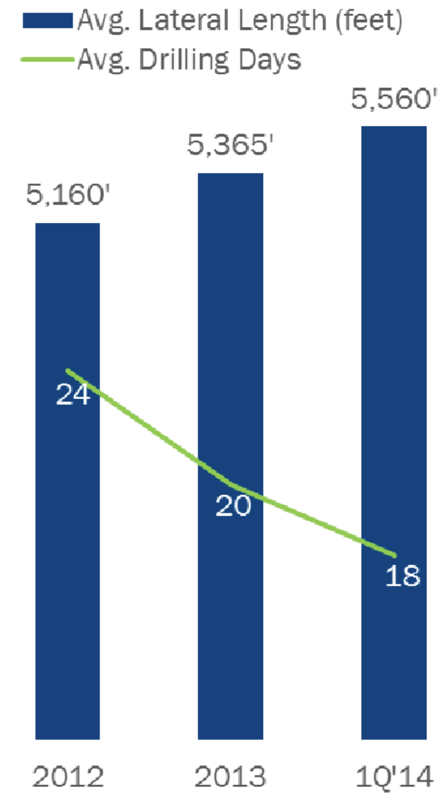
Data provided above based on gross operated wells turned in line and assumes normalized prices of $4.00/mcf and $90/bbl oil.
Incudes 1,396, 1,388 and 226 wells in 2012, 2013 and 1Q'14, respectively

OPERATIONAL EFFICIENCIES: DRILLING FOCUS



90%
Planned Pad Drilling in 2014E

~1 rig yr.
Annualized rig-skid savings 1Q'14 vs. 2013



41 wells
Annualized equiv. wells 1Q'14 vs. 2013 avg. LL

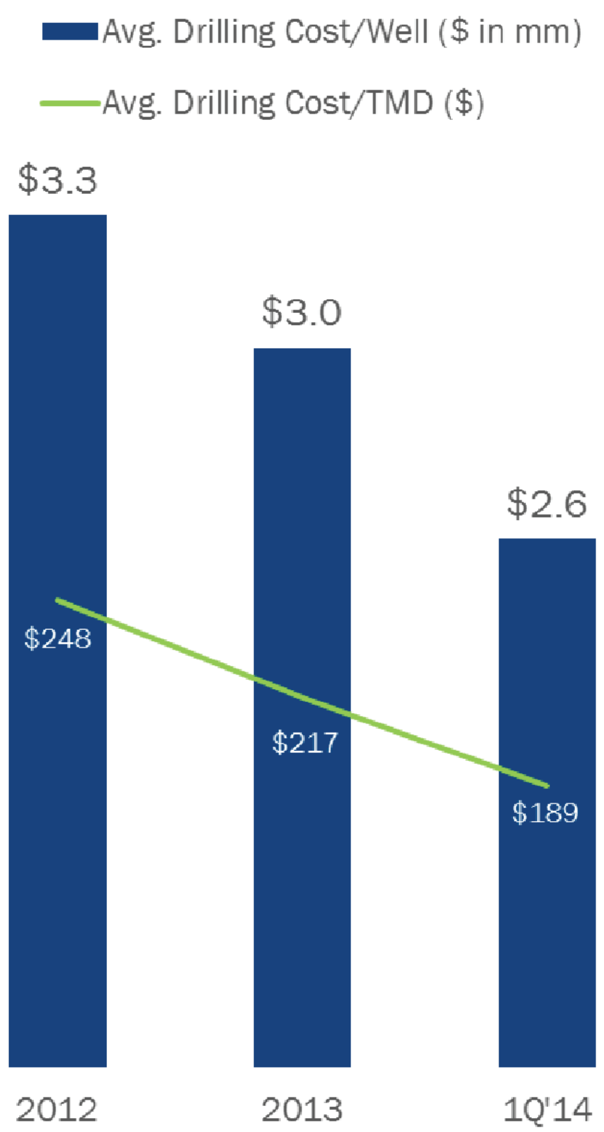
6.3 rig yrs.
Projected time saved 2014E vs. 2013 spud to rig release cycle time(1)

- Multi-well pad drilling efficiencies
  - Rig mobilization/skid time improvements
  - Leverage previously invested capital
- Focused engineering/improved planning
  - Peake drilling process
  - 24/7 Drilling Operations Center

(1) Assumes ~1,200 total wells drilled in 2014E

Chesapeake ENERGY

DRILLING EFFICIENCY IMPACT



LONGER LATERALS
FASTER, CHEAPER DRILLING
MORE VALUE

$470 mm

Total annualized avg. gross drilling capital savings 1Q'14 vs. 2013(1)

(1) Assumes ~1,200 total wells drilled in 2014E

DRILLING OPERATIONS CENTER VIDEO

DRILLING OPERATIONS CENTER BETTER GEOSTEERING …

- Projected to drill ~7 million lateral feet in 2014
- Increased lateral length in-target zone 3% in 1Q'14 vs. 2013

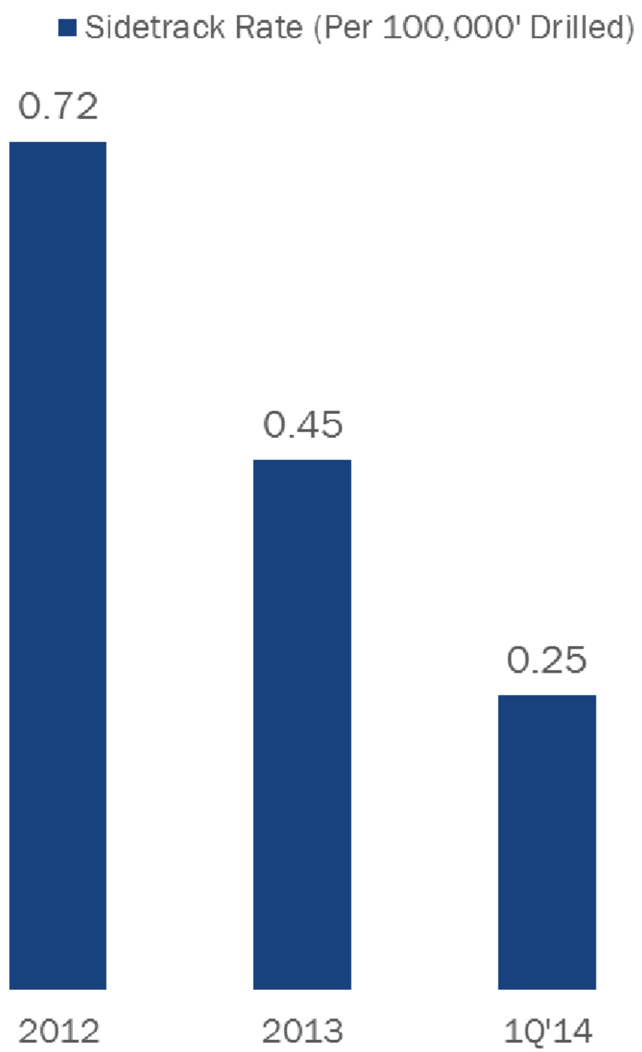
8.8 wells
1Q'14 incremental well equivalent

26 mmboe
Annualized 1Q'14 incremental access to reserves

$330 mm
PV10 annualized incremental reserves captured

Data above assumes average type well; 2014E avg. lateral length of ~6,000'

… AND SIDETRACK EVENT REDUCTION

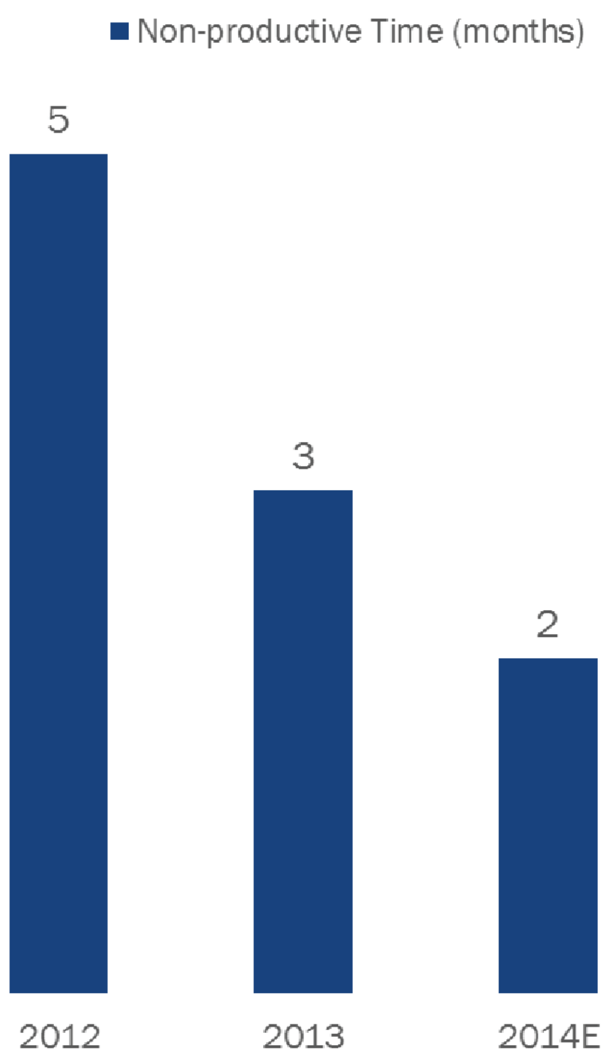


- Increased monitoring and focus on geosteering has significantly reduced rate of sidetrack events
- Projecting to drill ~16 mm ft. in 2014
- Estimated avg. cost of $500,000 per sidetrack event

44%
Sidetrack rate reduction
1Q’14 vs. 2013

~$16 mm
Annualized gross savings
1Q’14 vs. 2013

PRODUCTION ACCELERATION: REDUCING NON-PRODUCTIVE TIME (NPT)



- NPT is a major source of value leakage
- Leveraging existing infrastructure
  - > Minimizes NPT
  - > Accelerates production cash flow
  - > Increases per well rates of return

30%
Reduction in NPT 2014E vs. 2013

$50,000
Increase in NPV/well 2014E vs. 2013

$58 mm
Annualized increase of total program NPV 2014E vs. 2013

Non-productive time improvement since 2012 consists of a two month improvement waiting on pipeline (WOPL) and a one month improvement waiting on completion (WOC)

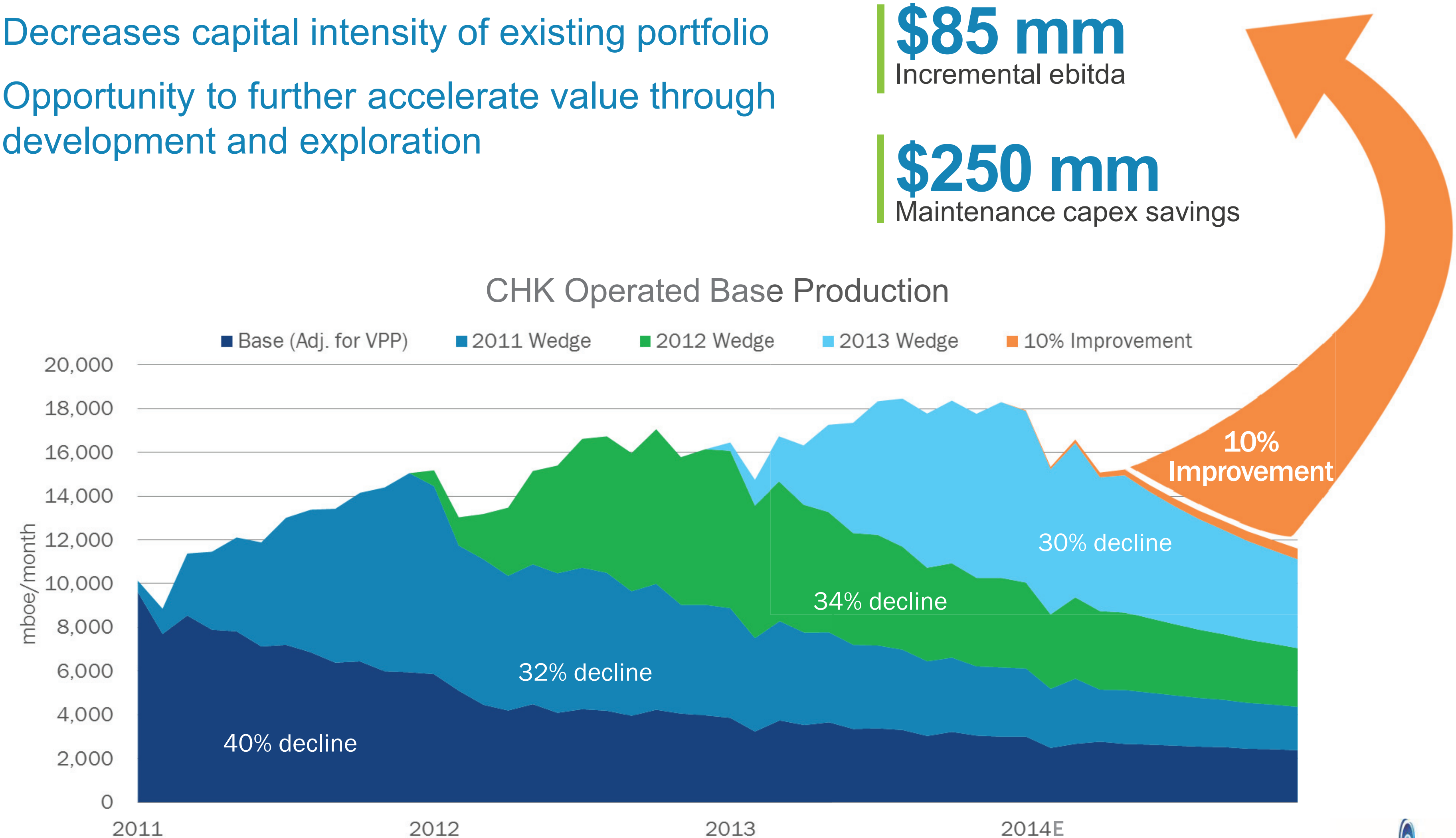
PRODUCTION ACCELERATION: OPTIMIZING THE BASE

- Targeting improvement in base decline rate from 30% to 27%
- Decreases capital intensity of existing portfolio
- Opportunity to further accelerate value through development and exploration

4 mmboe
Incremental production

$85 mm
Incremental ebitda

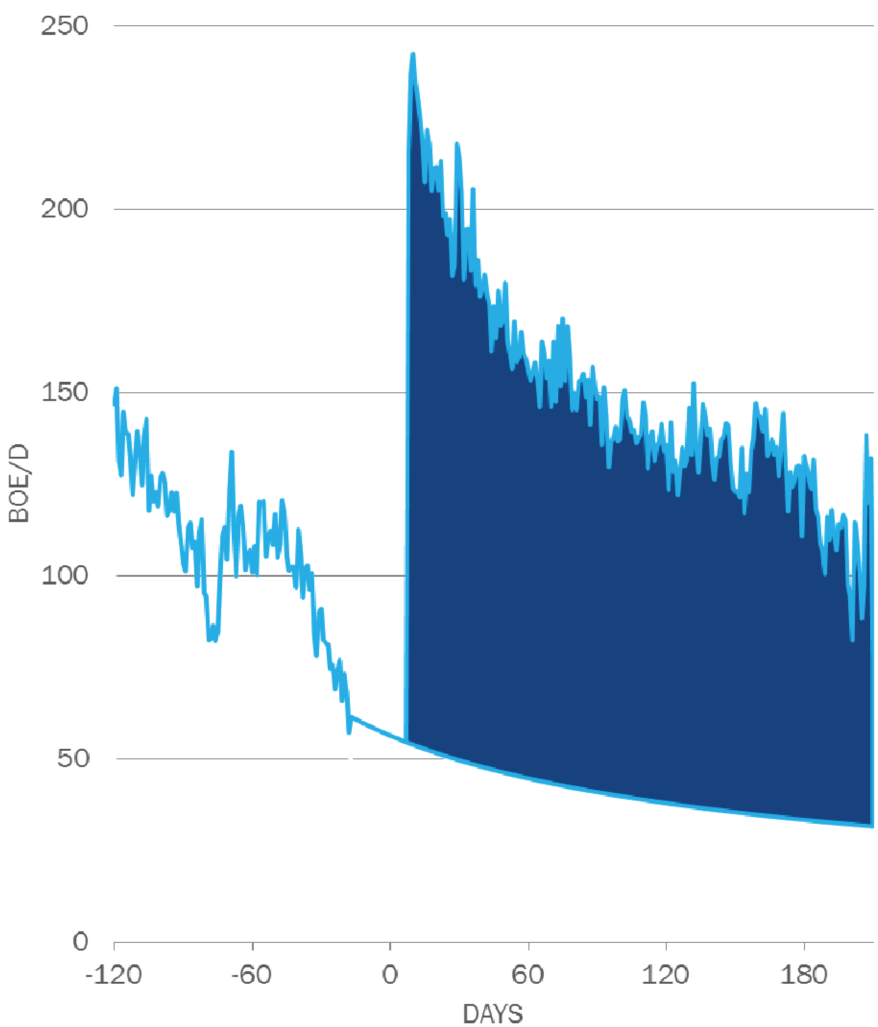
$250 mm
Maintenance capex savings



Chesapeake ENERGY

PRODUCTION ACCELERATION: ARTIFICIAL LIFT FOCUS

South Texas Artificial Lift(1)



- Efforts to optimize base production in Eagle Ford Shale underway
- 370 installations planned in 2014

20 mboe/well
Incremental production in year 1 post install

>100%
Rate of return on install projects

<6 months
Project achieves positive cash flow

24,750 CHK operated wells
8,000 wells with artificial lift currently – substantial optimization opportunities remaining

(1) Time normalized plot of 4Q'13 – 1Q'14 well set (95 wells)

Chesapeake ENERGY

SUPPLY CHAIN INITIATIVES

NEW
SUPPLY CHAIN
MANAGEMENT IS
CREATING
VALUE

Strategic Sourcing

- Consolidation / leverage of enterprise spend
- Value focused – price / quality

Process Consistency

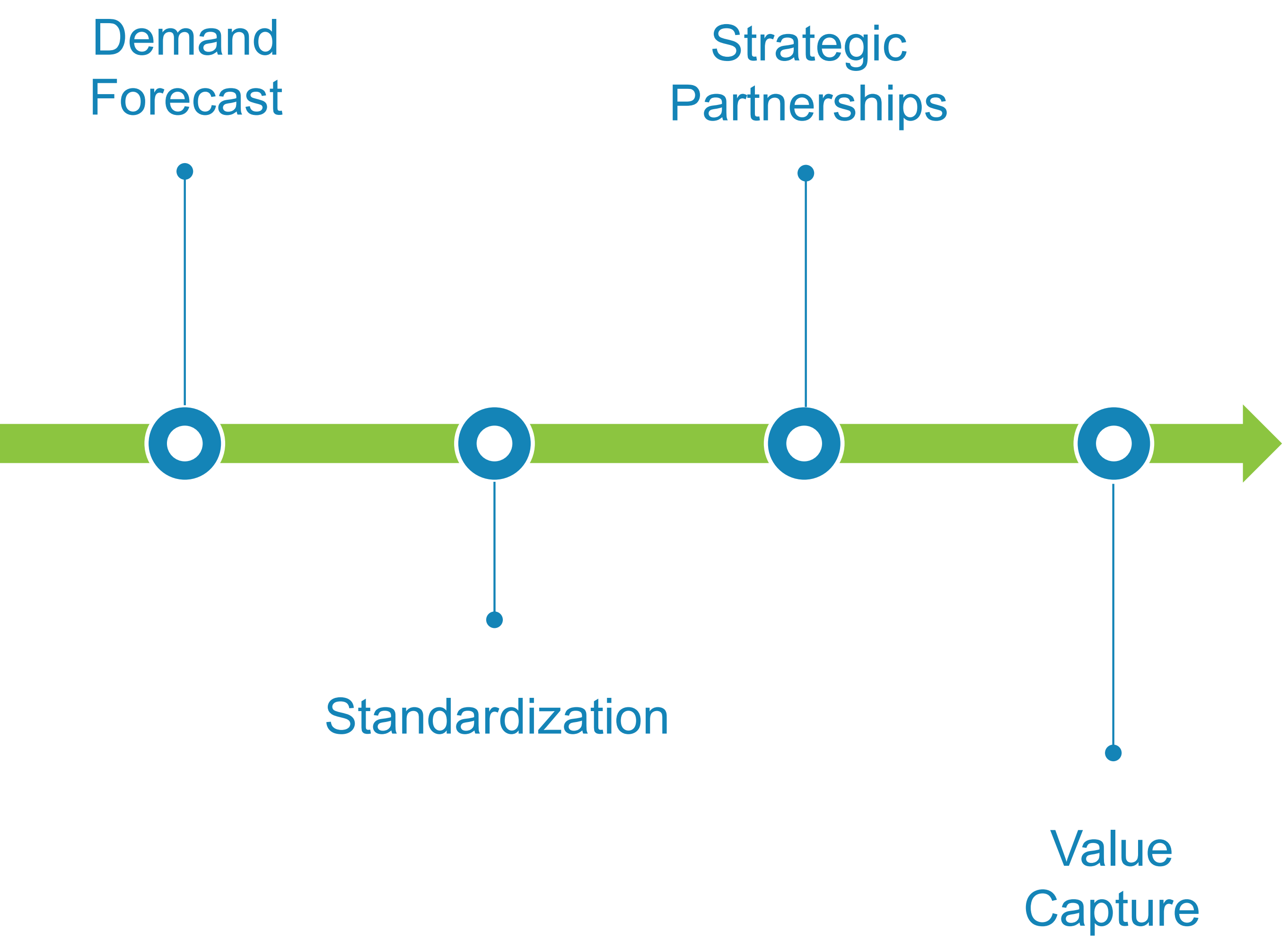
- Product / service standardized specifications
- Supplier pre-qualification

Planning / Forecasting

- Integrate Division, BU and supply chain planning
- Strategic inventory and logistics management

Chesapeake ENERGY

DELIVERING SUPPLY CHAIN VALUE



$350 mm
2014E projected annualized gross cost savings

>$200 mm
2014E projected annualized net cost savings

DELIVERING VALUE

OPERATIONAL
EFFICIENCIES

+

PRODUCTION
ACCELERATION

+

SUPPLY CHAIN
VALUE

=

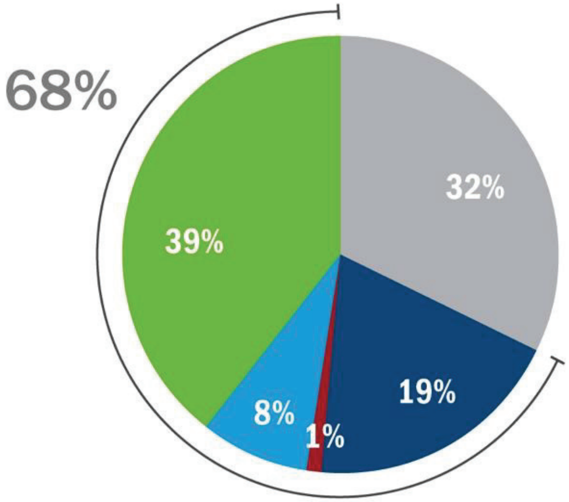
>$1.0 B
IN ANNUALIZED
COST
IMPROVEMENT
FOR 2014

SOUTHERN DIVISION

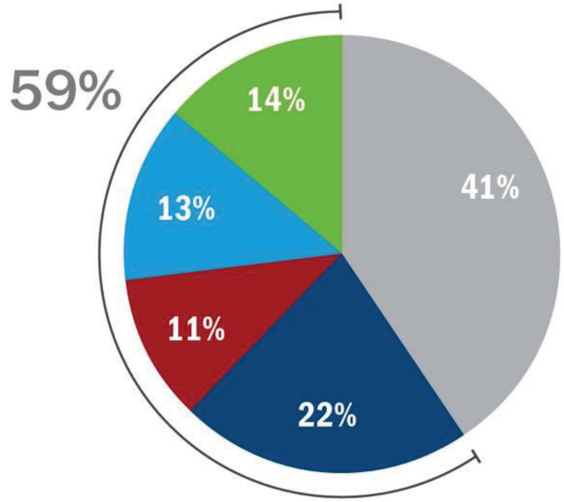
JASON PIGOTT
SVP - OPERATIONS
SOUTHERN DIVISION

SOUTHERN DIVISION OVERVIEW

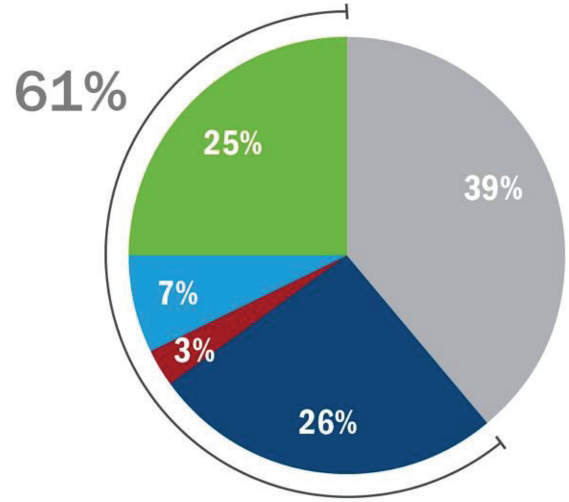
1Q 2014 CAPEX



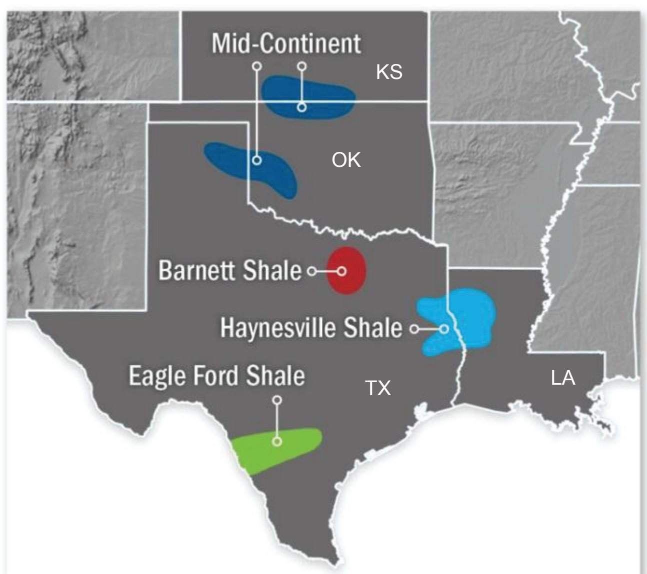
1Q 2014 PRODUCTION



1Q 2014 EBITDA



- Eagle Ford Shale
- Haynesville Shale
- Barnett Shale
- Mid-Continent
- Northern Division

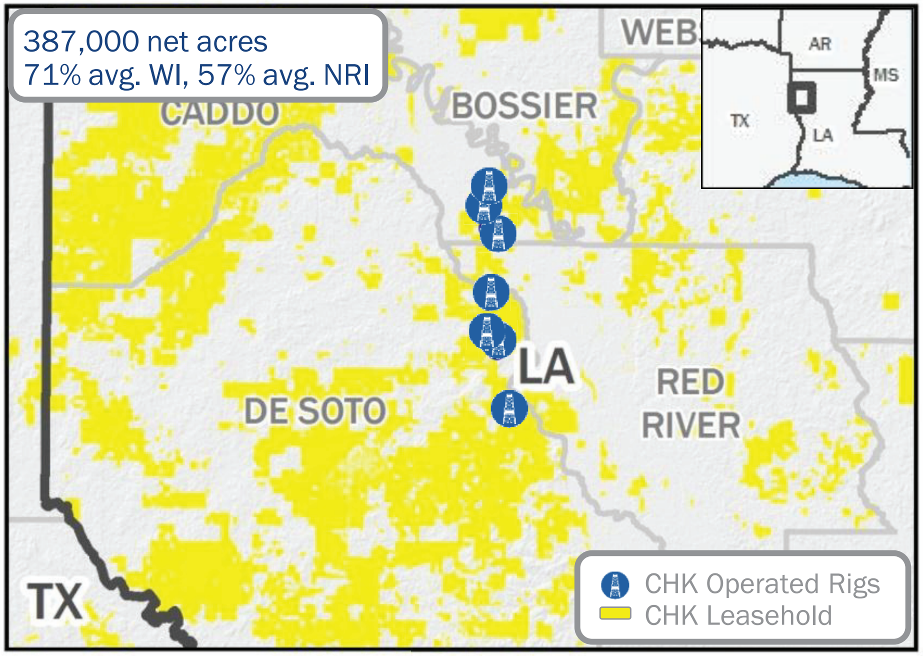


Note: data above assumes E&P capex only, excludes corporate Ebitda adjustment

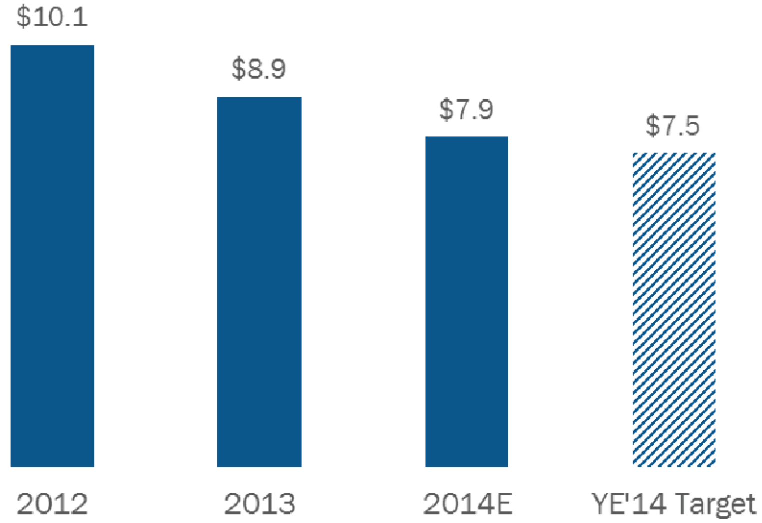
HAYNESVILLE
UNLOCKING LEADING RETURNS

HAYNESVILLE
ASSET OVERVIEW

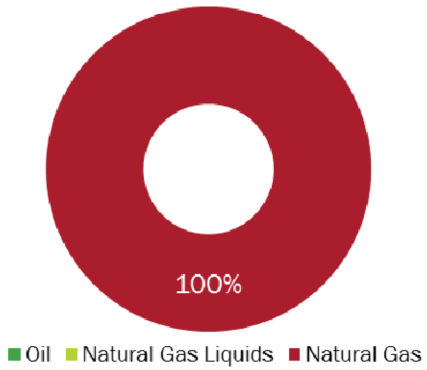
- ~10 tcfe of net recoverable resources
- Net production of 495 mmcfe/d[(1)]
- 7 - 9 operated rigs in 2014
- $7.5 mm well cost target achieved in 1Q'14
- Best well to date = $6.9 mm



Avg. Well Costs ($ in mm)



Production mix[(1)]



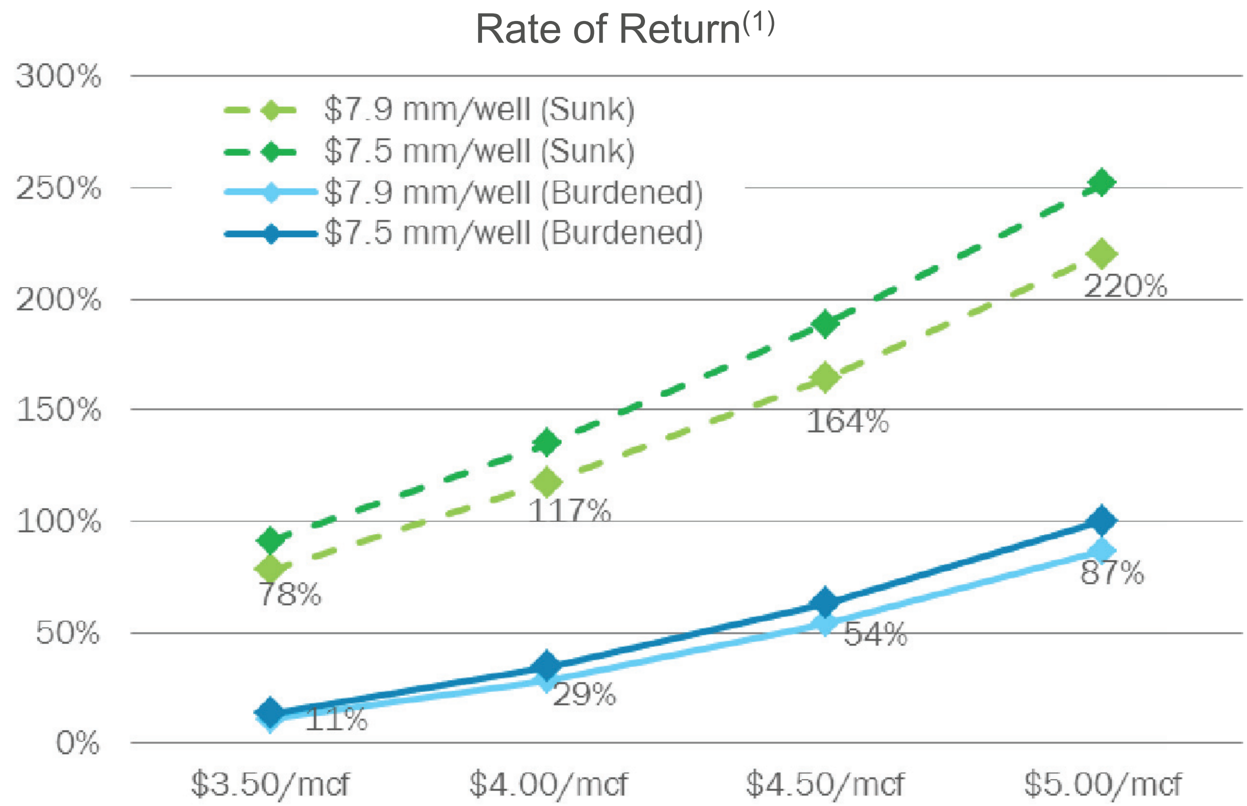
Operated locations[(2)]

Drilled	749
Producing	728
Inventory	14
Undrilled	1,900+

(1) 1Q'14 daily avg. net production
(2) Gross operated locations as of 3/31/2014; drilled locations include plugged and abandoned; undrilled locations exclude Bossier Shale

Chesapeake ENERGY

HAYNESVILLE ECONOMICS

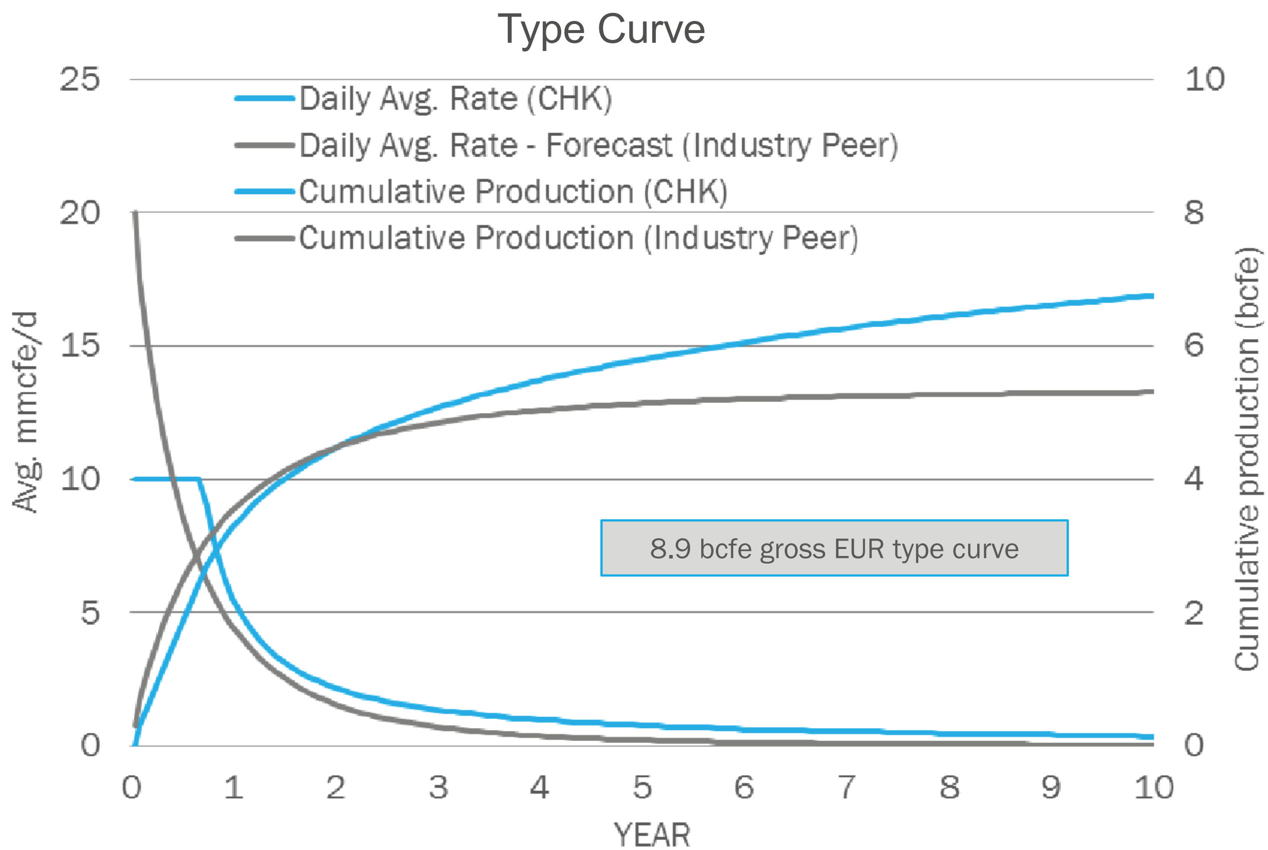


>100%
Unburdened ROR in Haynesville

- Cost control measures and improving natural gas prices drive stronger returns
- ROR exceeds 100% when considering minimum volume commitment (MVC) and firm transport (FT) as sunk costs

(1) Burdened ROR scenarios assume differentials to NYMEX natural gas prices of ($1.45)/mcf for gathering/transportation costs and regional basis differential. Also assumes 180 day spud to TIL cycle time delay for a three well pad.
Note: rates of return represent 2014 program

HAYNESVILLE
ENHANCING EUR WITH FLOWBACK MANAGEMENT

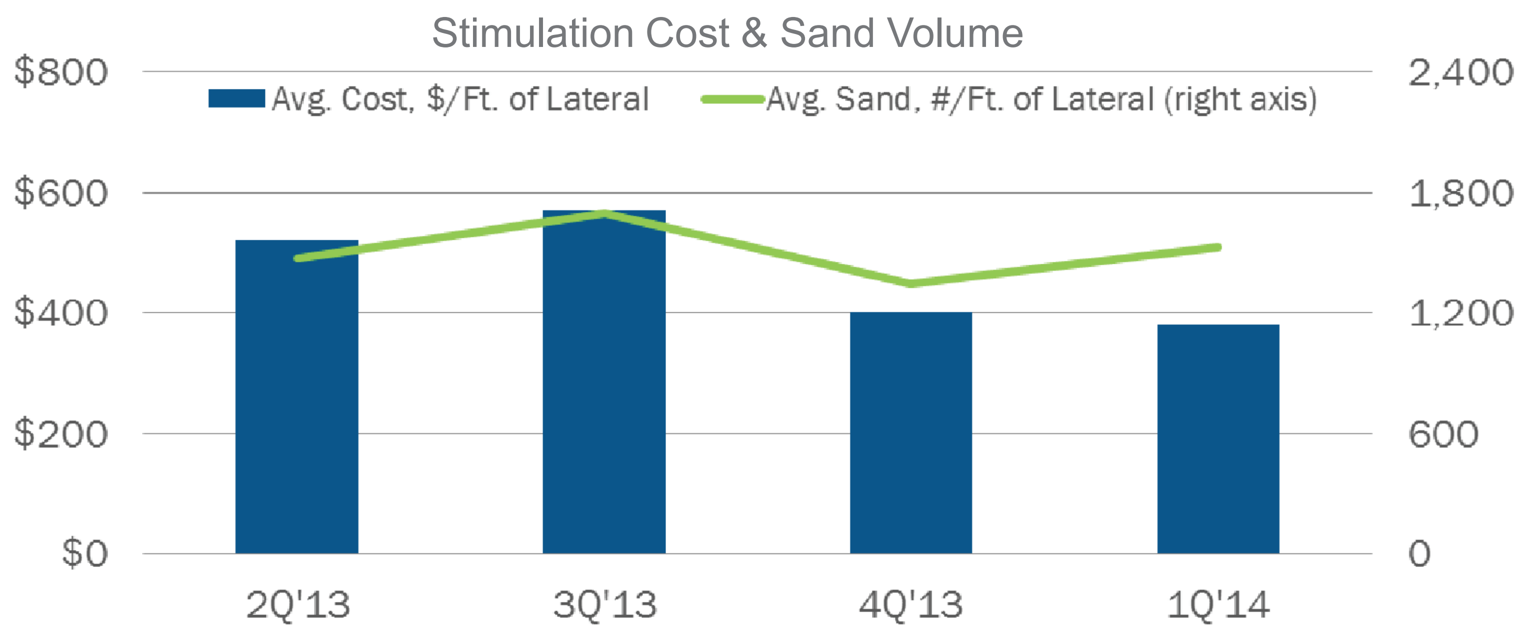


65%
EUR improvement vs. industry peer

- Restricted rate flow backs enhances EUR by 65%
- Development for 2014 on 160 acre spacing

Note: type curve represents 2014 program

HAYNESVILLE
FOCUSED ON STIMULATIONS



- New organizational structure includes dedicated completions teams
- Design optimization
  - > Decreasing completion chemical usage
  - > Alternate stimulation designs including slick water treatments
  - > Modifying proppant composition
  - > Maintaining total sand volume

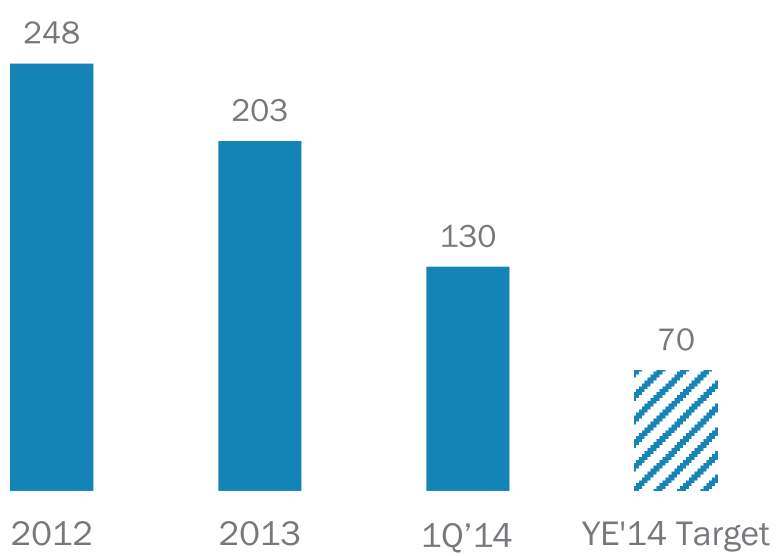
27%

Decrease in stimulation costs for similar sized jobs from 2Q'13 to 1Q'14

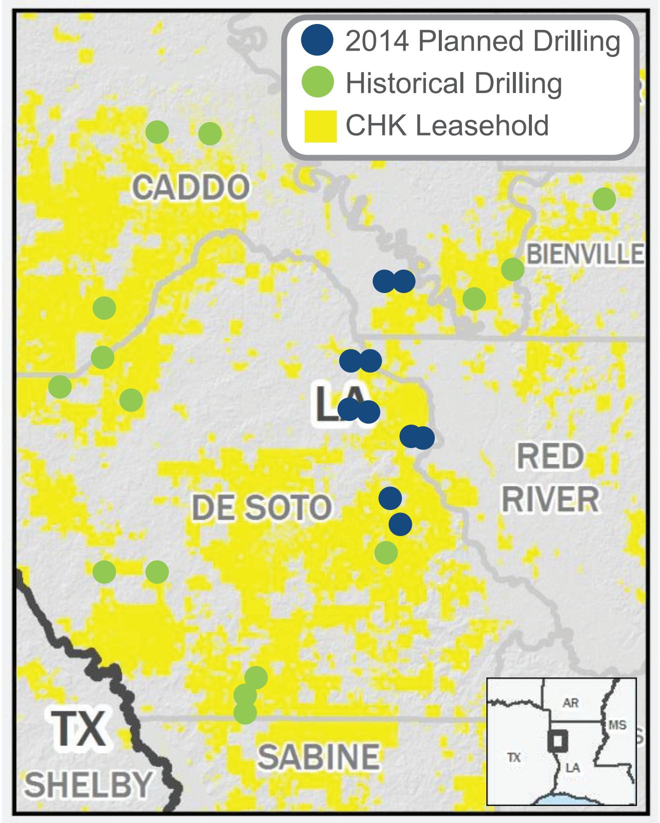
HAYNESVILLE
BENEFITS FROM HISTORICAL INVESTMENT

- Pads & pipelines in place
- Return-driven drilling vs. acreage capture
- Substantial incremental revenue generation capability

Haynesville Rig Release to TIL (days)



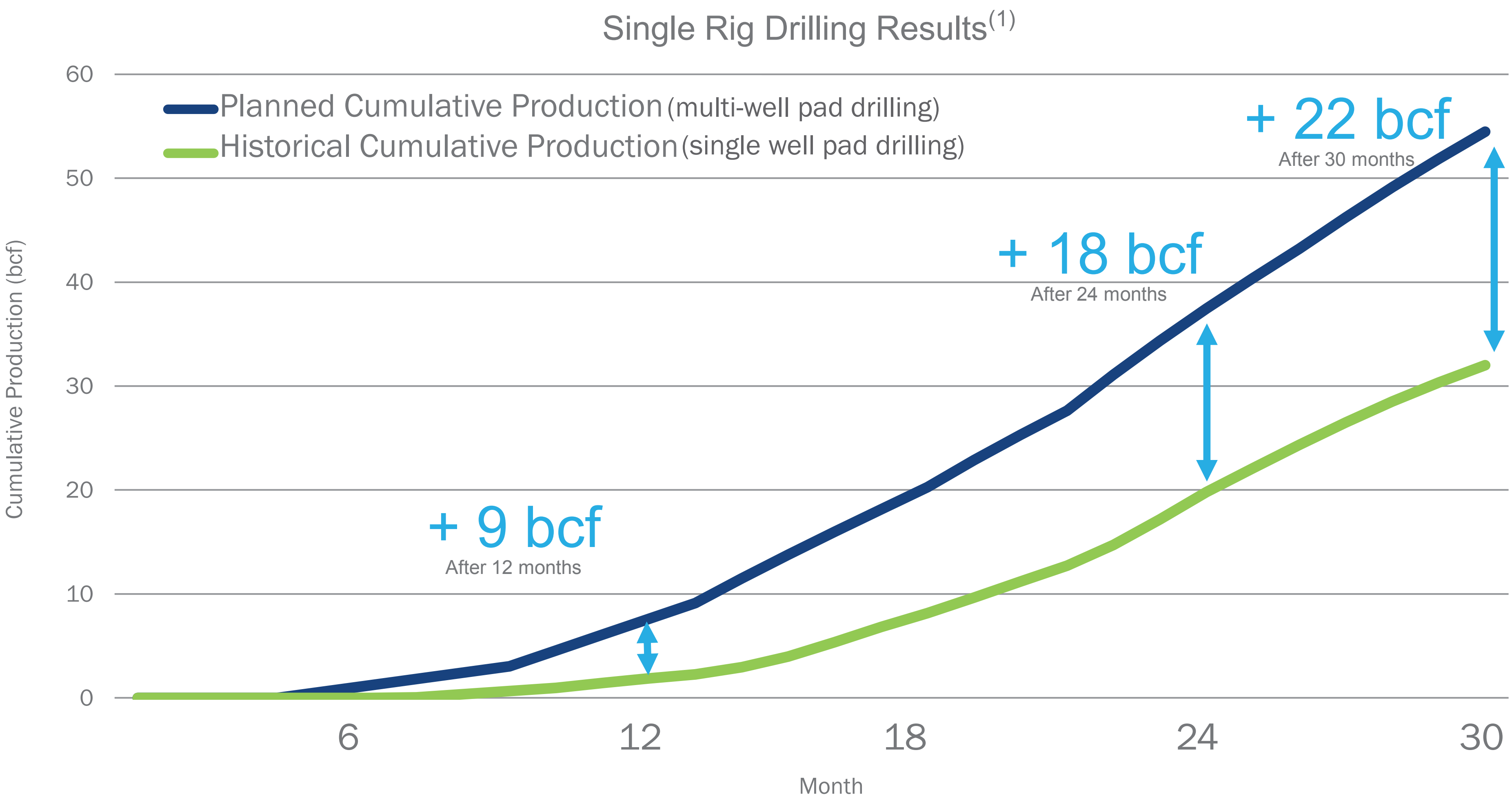
Single Rig Movement



65%
Projected decrease in rig release to TIL YE'14 vs. 2013

Chesapeake ENERGY

HAYNESVILLE PRODUCTION ACCELERATION



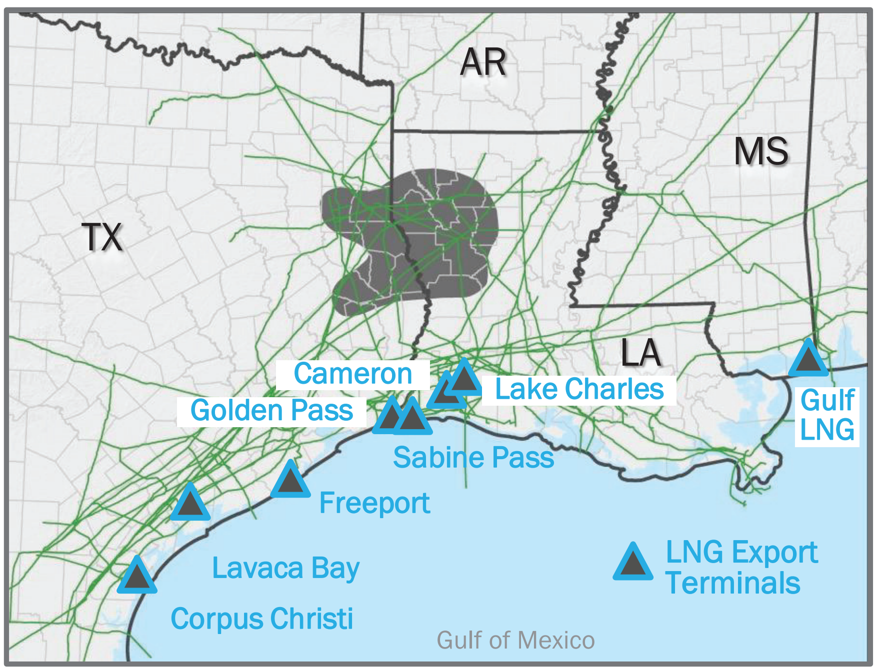
Accelerated production delivering greater cash flow

(1) Historical rig line includes 15 wells on single well pads from 2012-13; planned includes 15 wells in 2014 scheduled on five pads (3 wells/pad)

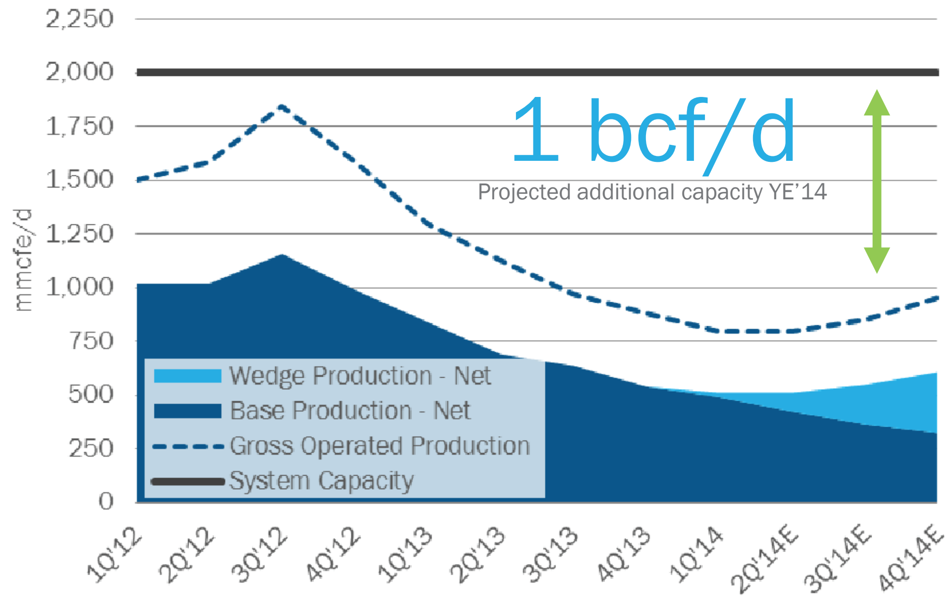
Chesapeake ENERGY

HAYNESVILLE MIDSTREAM ADVANTAGE

- Significant available capacity in place
- Quick rig ramp up capability



Haynesville System Capacity and Production



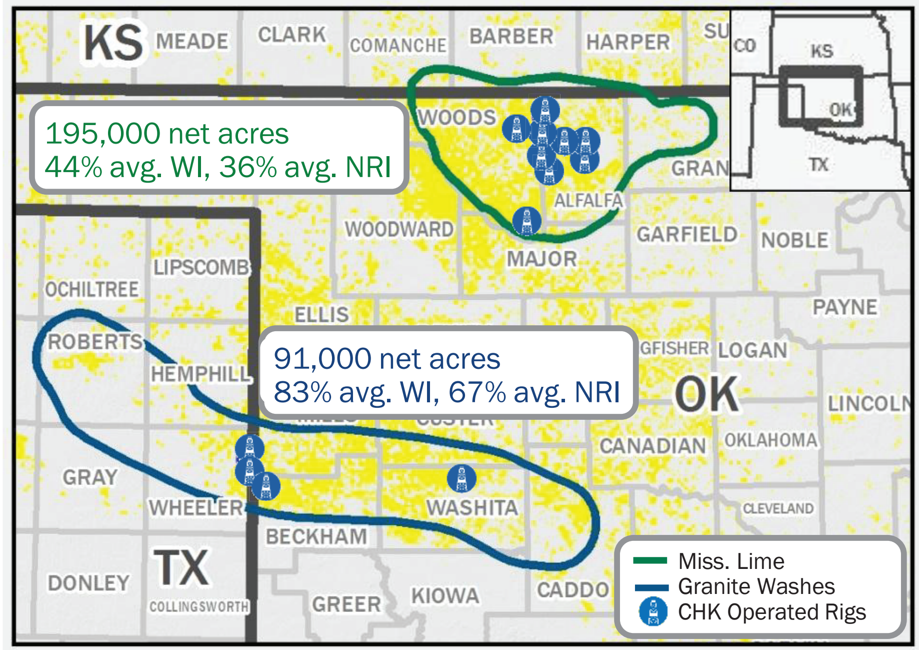
- Attractive Henry Hub markets
- Close proximity to LNG facilities

Chesapeake ENERGY

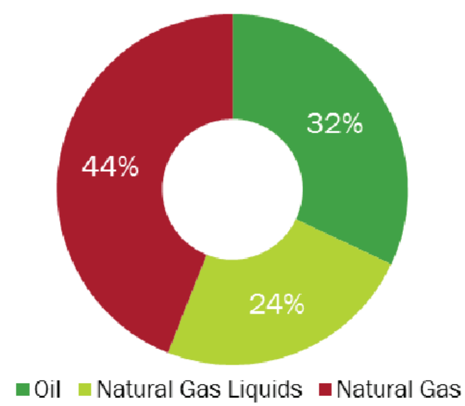
MID-CONTINENT
DELIVERING VALUE THROUGH DISCIPLINE

MID-CONTINENT ASSET OVERVIEW

- 286,000 net acres actively being developed in aggregate
  - > Mississippian Lime
    - > More than 500 mmboe of net recoverable resources
  - > Granite Wash plays[1]
    - > More than 350 mmboe of net recoverable resources
  - > ~1.9 mm net acres of legacy leasehold
- Net production of 101 mboe/d[2]
- 12 - 14 operated rigs in 2014
- ~20% of 2014 estimated E&P capex



Production mix[2]



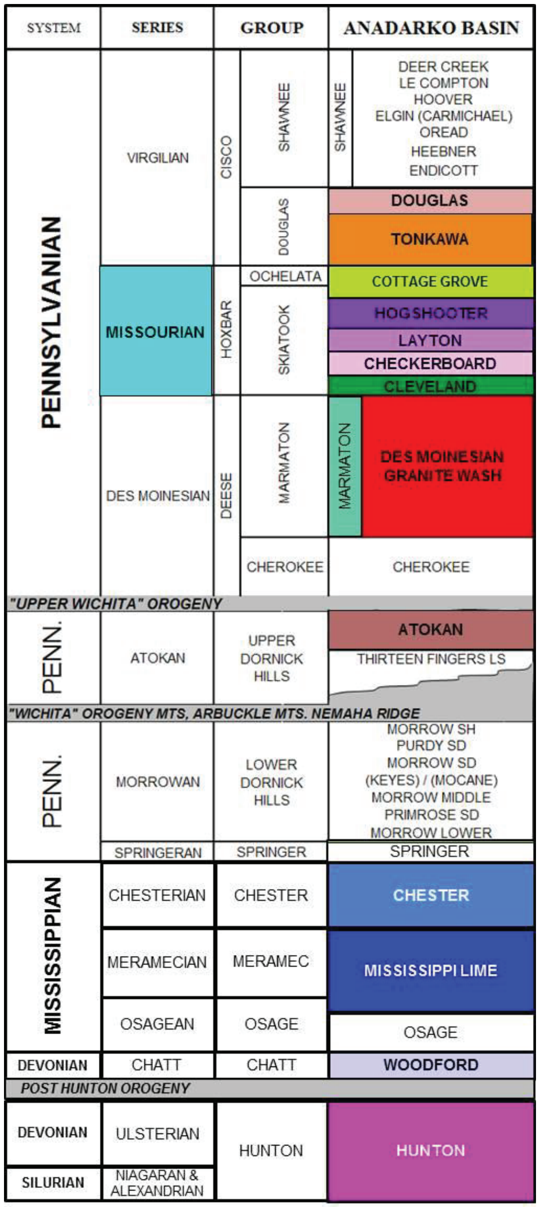
Operated locations[3]

Drilled	1,455
Producing	1,395
Inventory	40
Undrilled	4,400+

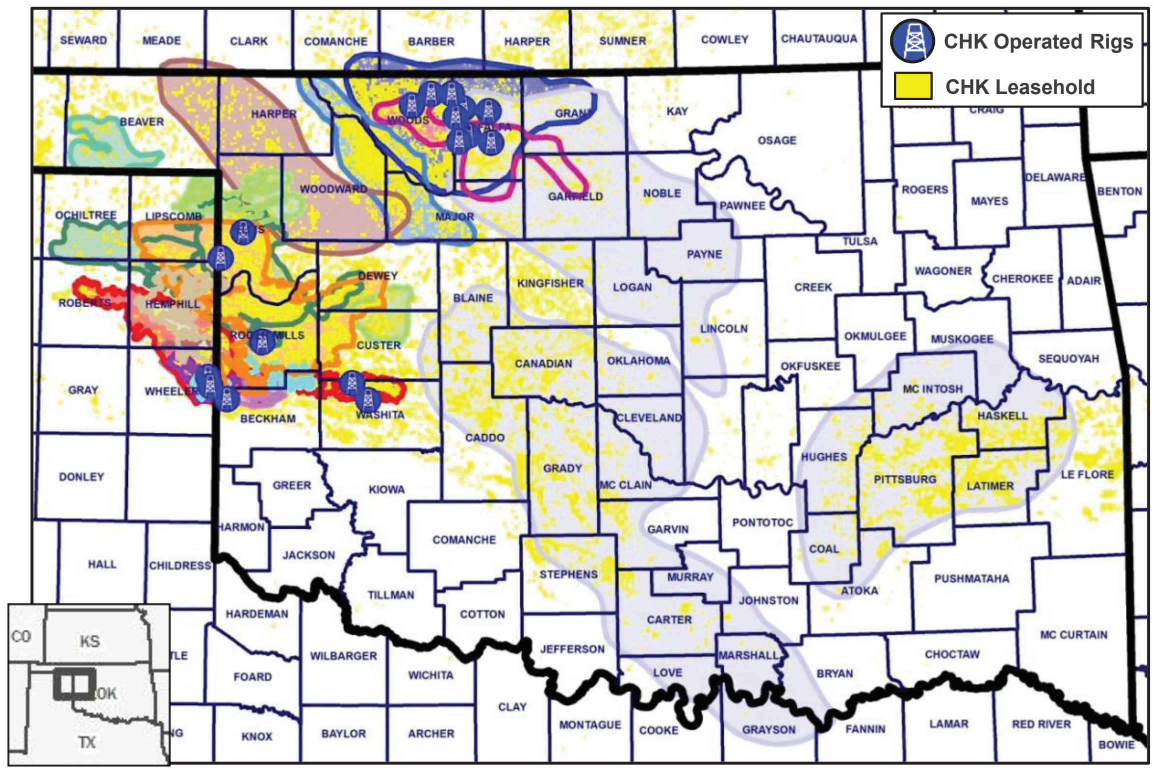
(1) Granite Wash plays include Colony Granite Wash, TX Panhandle Granite Wash, Missourian Granite Wash and Hogshooter
(2) 1Q'14 daily avg. net production
(3) Gross operated locations as of 3/31/2014; drilled locations include plugged and abandoned

Chesapeake ENERGY

MID-CONTINENT
STACKED OIL PAY DEVELOPMENT

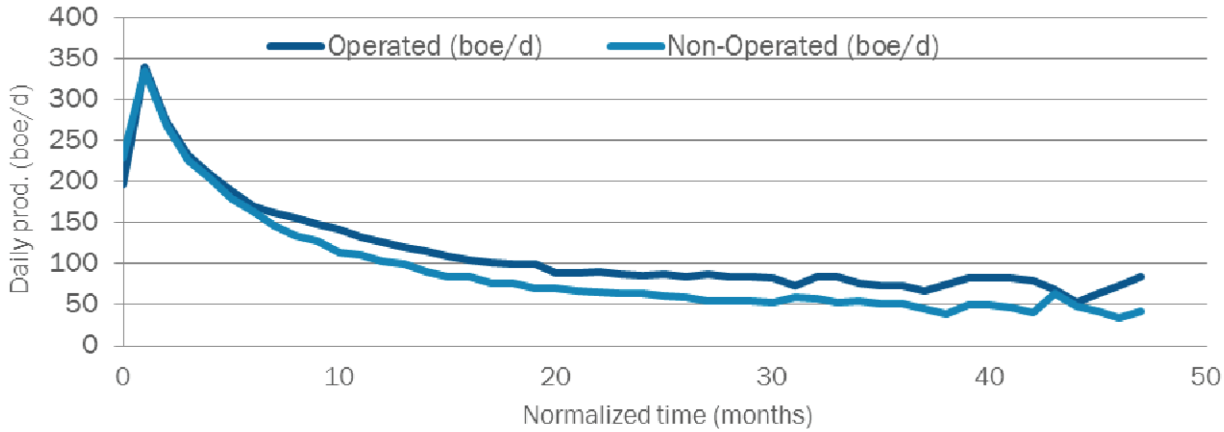


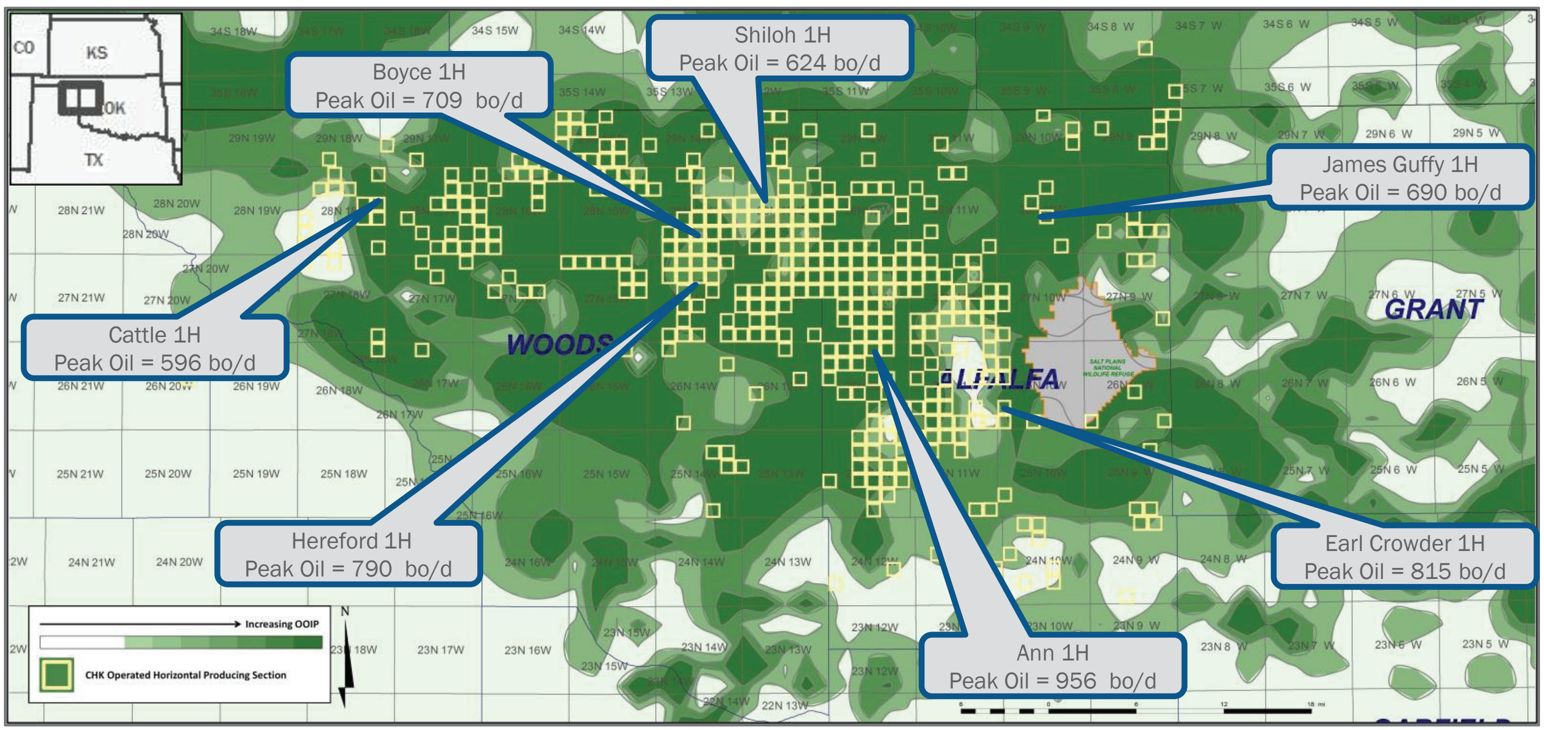
- Multiple growth opportunities in the Oswego/Marmaton, Atoka Lime, Chester, Middle/Lower Mississippi, Woodford, and Hunton
- Actively monitoring third-party activity
- Ability to leverage existing infrastructure



MID-CONTINENT
PREMIER MISSISSIPPIAN LIME POSITION

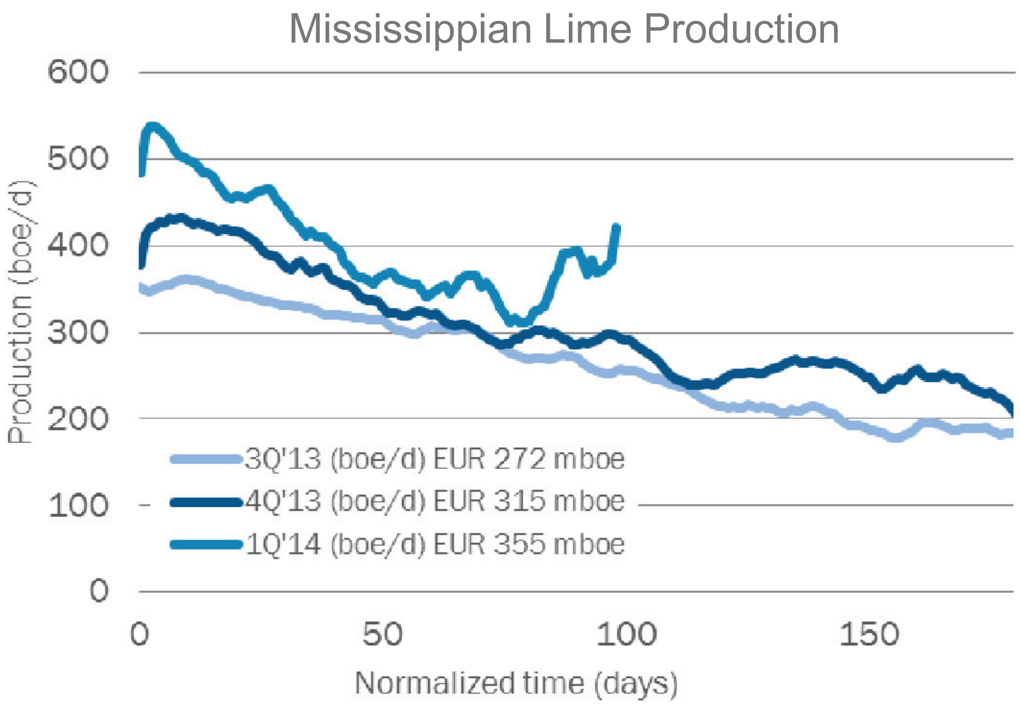
- ~160,000 high-graded operated net acres
- 3D coverage provides competitive advantage
- Generating higher ROR and more consistent results

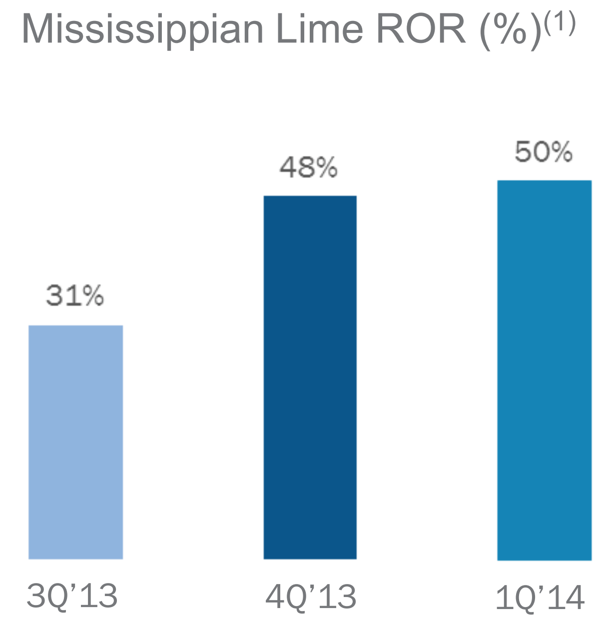




Chesapeake ENERGY

MID-CONTINENT
MISSISSIPPIAN LIME PRODUCTION IMPROVES





- Integrated teams are increasing project returns
- Improved EURs and performance from historical trends
  - > Reservoir characterization
  - > Targeting
  - > Steering
  - > Completion optimization

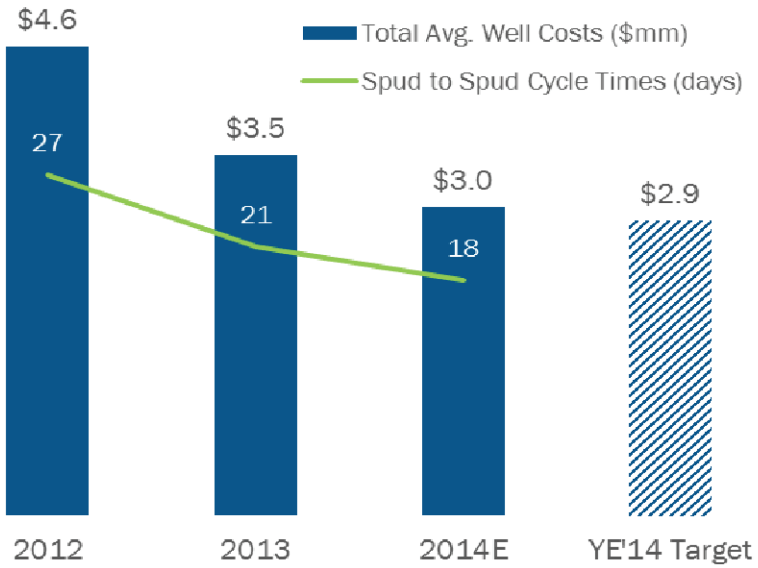
31%
Increased EUR performance from 3Q'13 to 1Q'14

(1) Based on a $4.00/$90/$36 price assumption

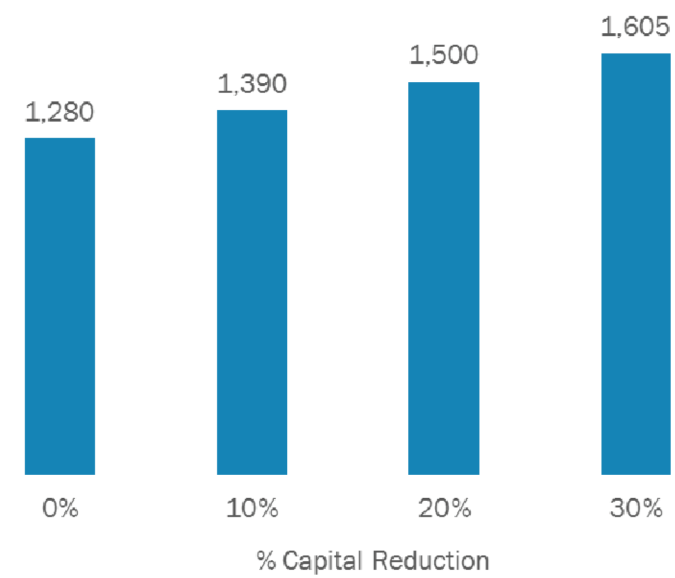
Chesapeake ENERGY

MID-CONTINENT
CORE EXPANSION FROM CAPITAL EFFICIENCY

Mississippian Lime Efficiencies



Drillable Inventory Increase from Efficiencies(1)



- ~20% decrease in well cost from 2013 to YE'14 target
- ~15% decrease in spud-to-spud cycle time from 2013 (21 days) to 2014 estimate (18 days)
- For every 10% decrease in well costs, drillable inventory increases by >100 wells

67%
2014 multi-well pad development

22
Wells D&C YTD for <$3.0 mm

(1) Based on a ROR hurdle of 10%

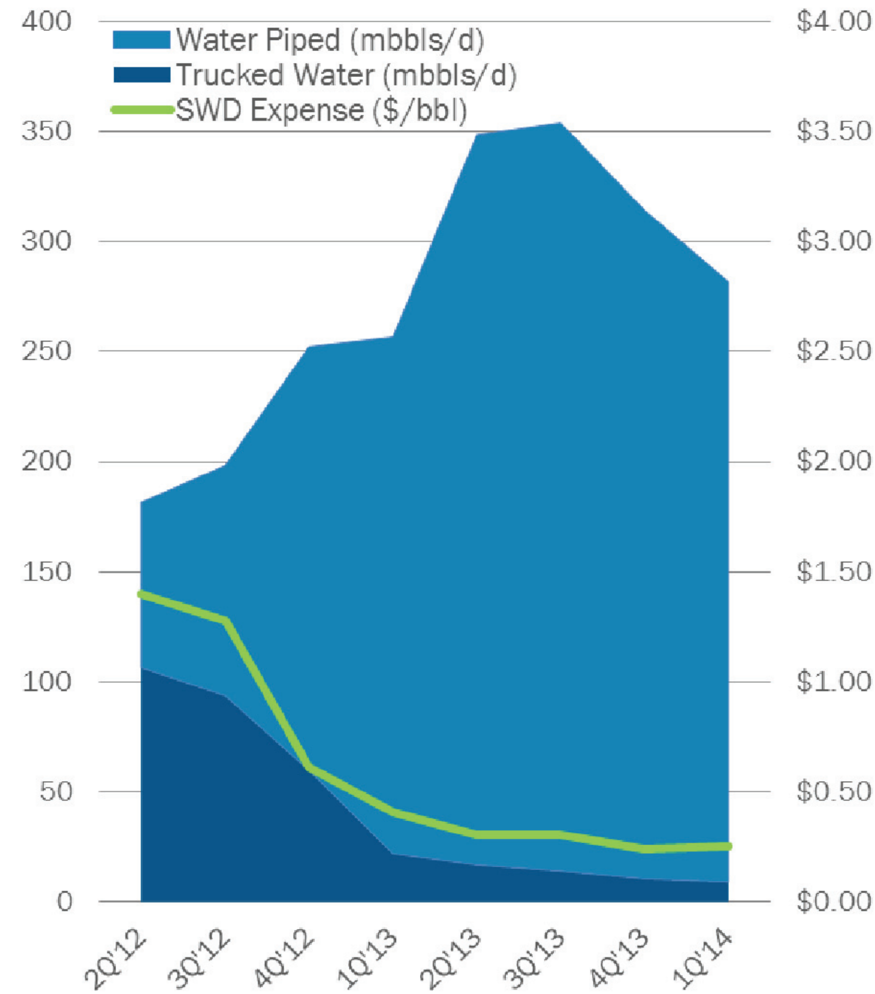
MID-CONTINENT INFRASTRUCTURE ADVANTAGE

- Capacity of ~350,000 barrels of salt water per day
- Recycling produced water for completions
- Generating ~$2.5 mm/year in 3rd party revenue

$98 mm/year

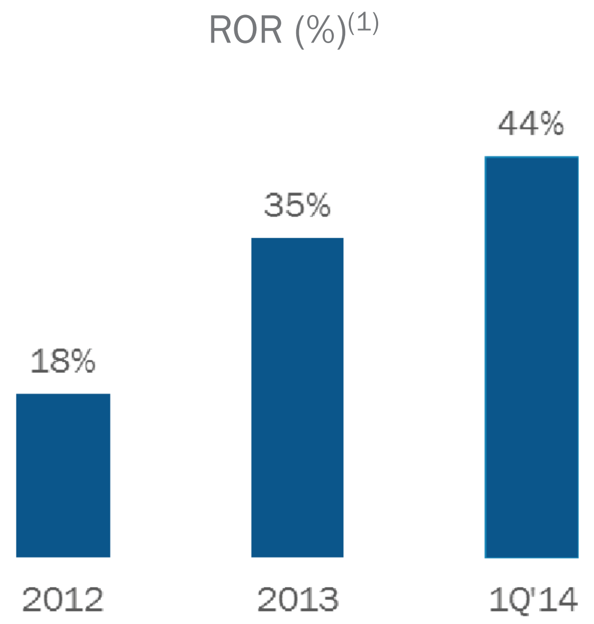
Annualized savings by reducing SWD expense by 85% from $1.50 to $0.26 per bbl of water[(1)]

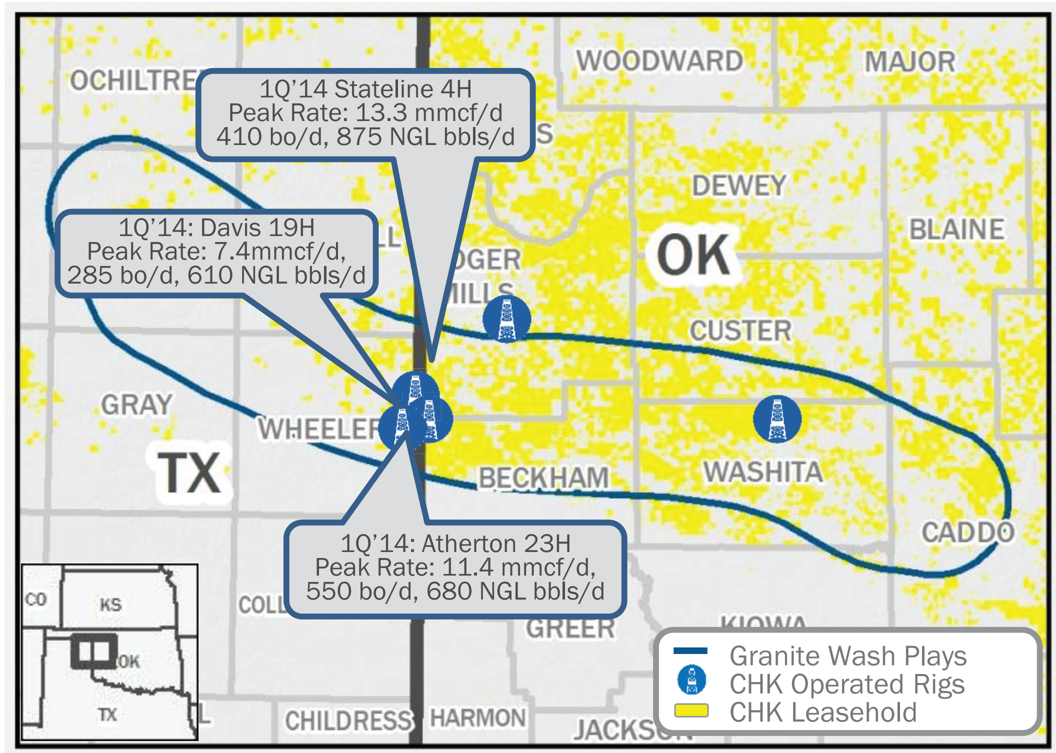
Salt Water Disposal Initiative



(1) Based on average water produced from 2Q'12 to 4Q'14

MID-CONTINENT GRANITE WASH PLAYS





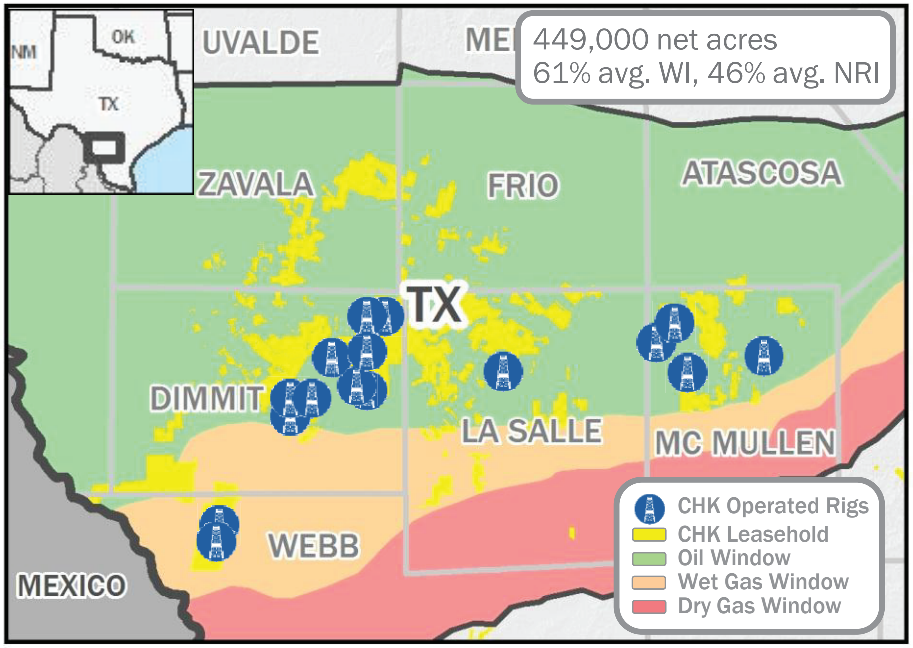
- Drilled >450 wells and participated in >320 non-operated wells
- Continue to drill core Granite Wash and extend productive limits
- Recently integrated 3D seismic with new geological model to high-grade locations
- 2015 development plan includes testing new targets

(1) Based on a $4.00/$90/$36 price assumption

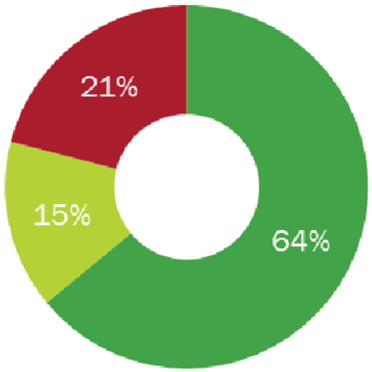
EAGLE FORD
A DEPENDABLE OIL GROWTH ENGINE

EAGLE FORD ASSET OVERVIEW

- ~1.2 bboe of net recoverable resources
- Current net production of ~95 mboe/d
- 15 - 20 operated rigs in 2014
- ~35% of 2014 estimated E&P capex



Production mix(1)



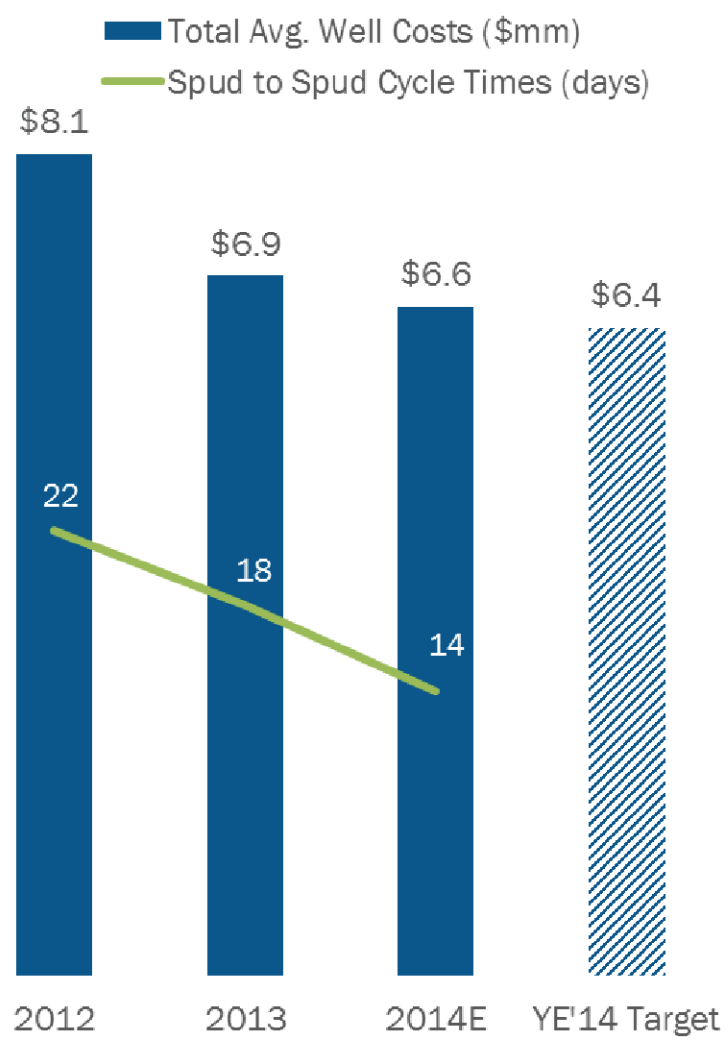
Operated locations(2)

Drilled	1,061
Producing	945
Inventory	114
Undrilled	4,300+

(1) 1Q'14 avg. daily production
(2) Gross operated locations as of 3/31/2014; drilled locations include plugged and abandoned

Chesapeake ENERGY

EAGLE FORD
CONTINUOUS IMPROVEMENT



- Conversion to multi-well pad drilling
- Substantial cycle-time improvements
- Testing new completion designs to lower cost and not impact performance
- Continuing to upgrade rig fleet

95%
Multi-well pad drilling in 2014

20%
Targeted decrease in spud-to-spud cycle time from 2013 to 2014E

7%
Targeted decrease in avg. well costs 2013 to YE'14 target

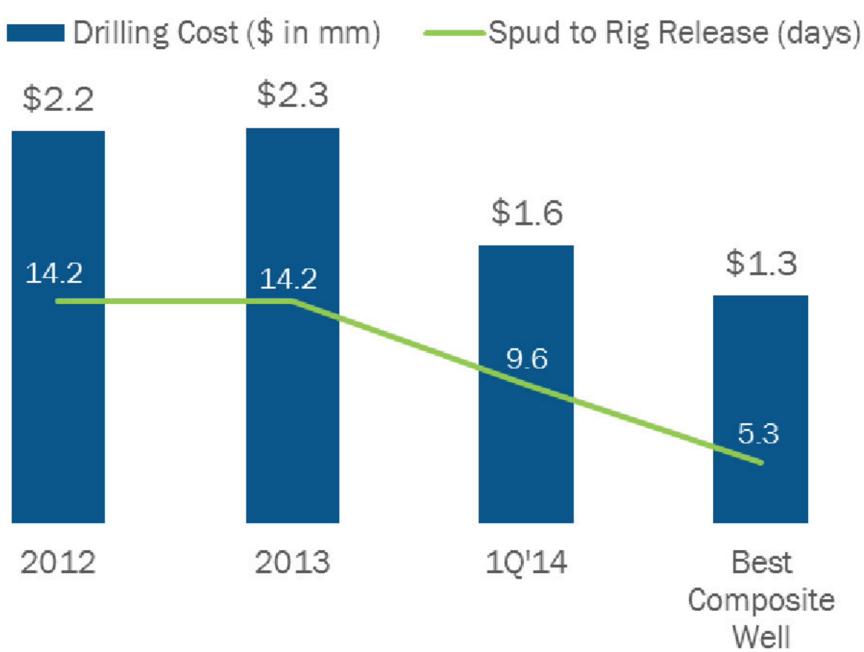
Chesapeake ENERGY

EAGLE FORD
FAITH RANCH DRILLING

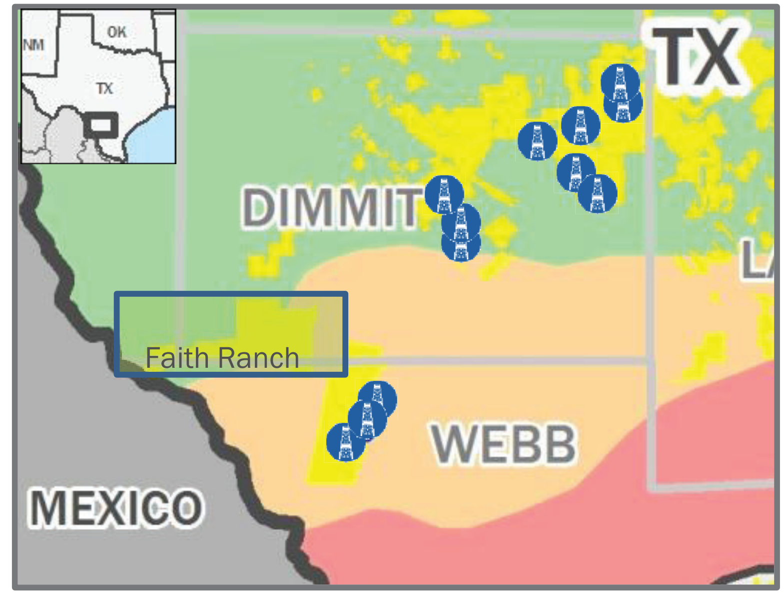
- New fit for purpose rigs making major advances in both drilling time and cost
- Implementation of best composite well system setting the new standard

30%
Decrease in Spud to RR days 1Q'14 vs. 2013

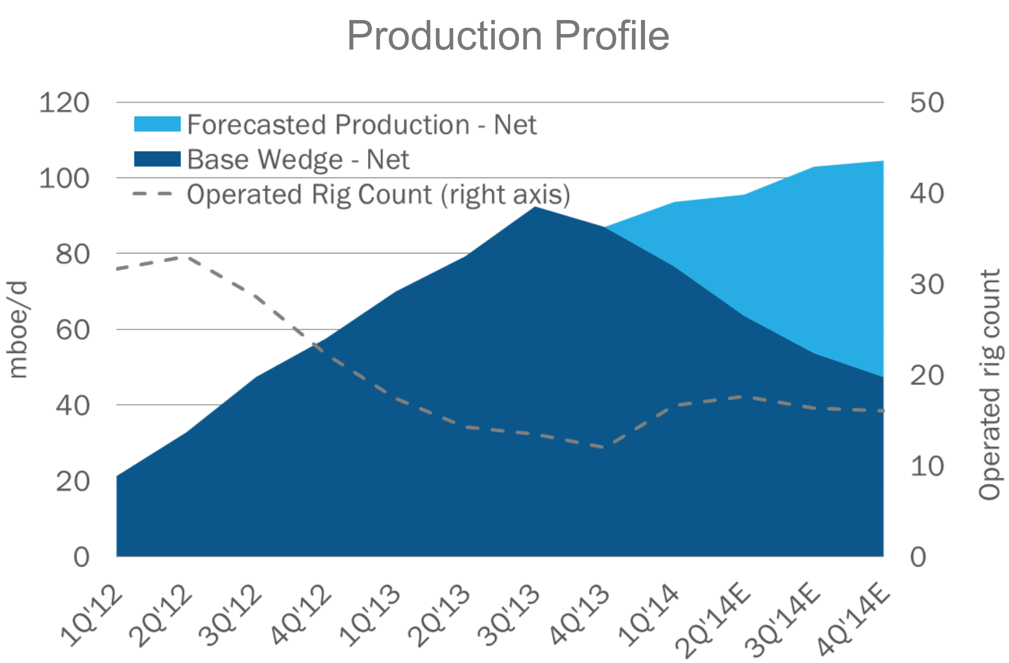
30%
Decrease in drilling costs 1Q'14 vs. 2013

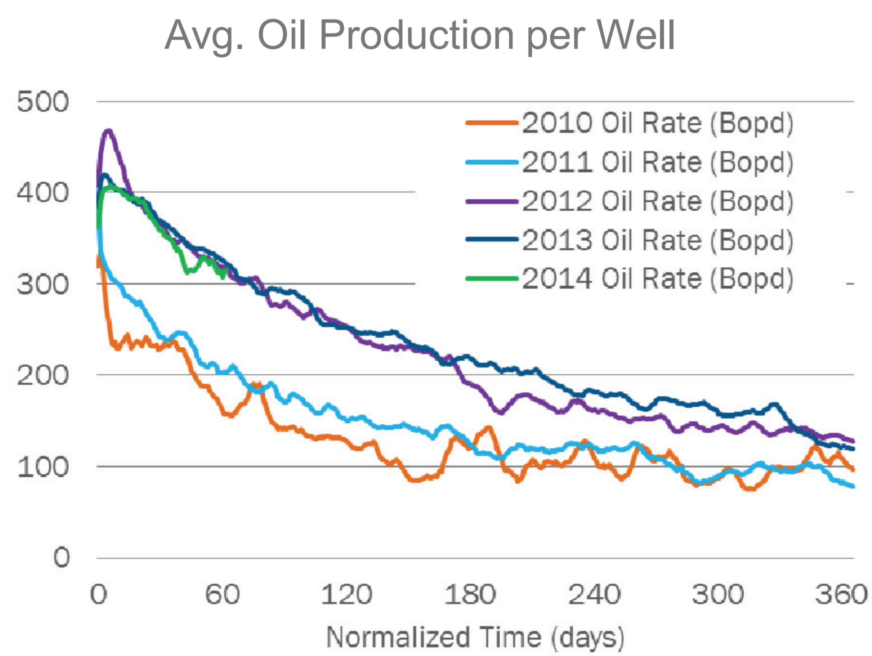


Chesapeake Faith Ranch Zone Leases



EAGLE FORD GROWTH





27%

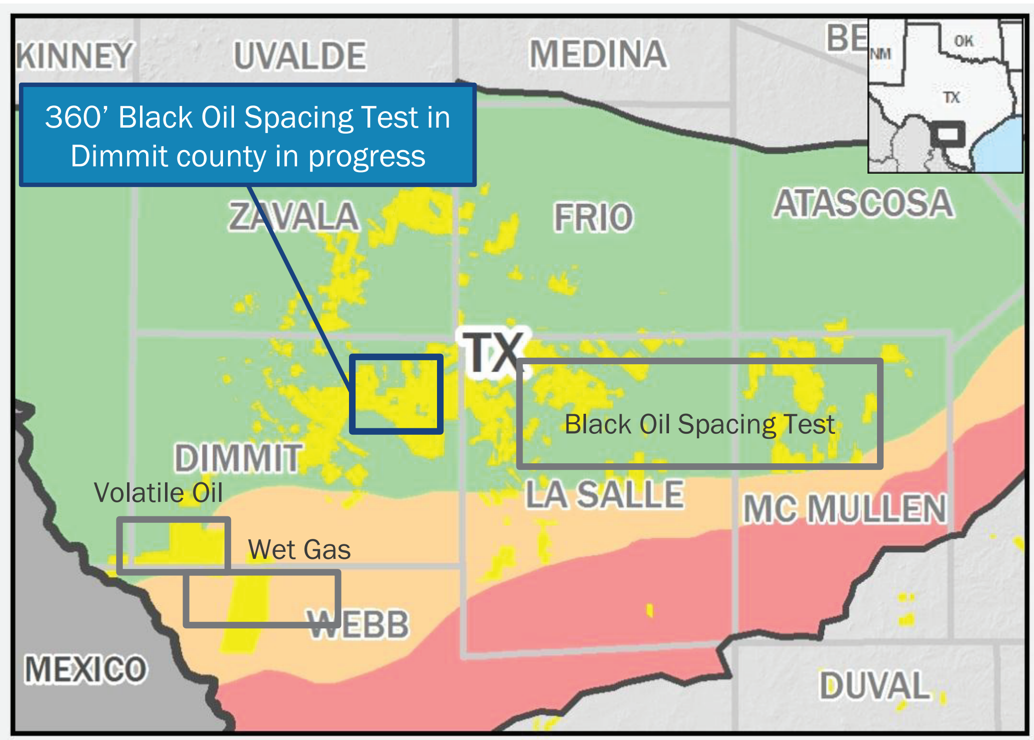
Net Production
CAGR 2012 - 2014E

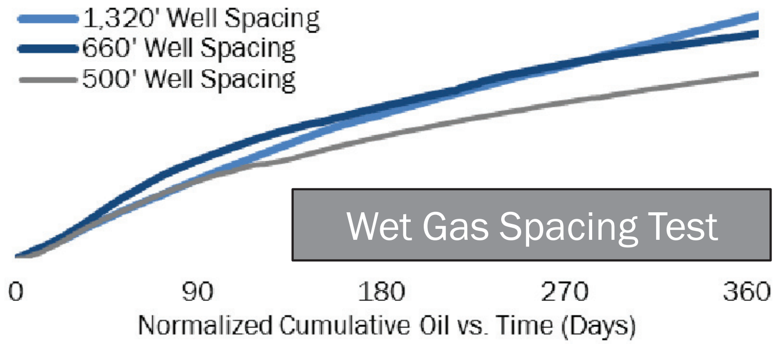
- Ramped rig count to 20 rigs
- Improved completion efficiency by reducing rig release to TIL cycle times by 32%

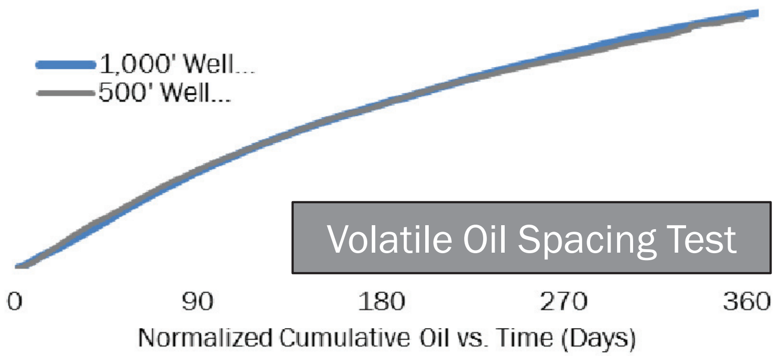
- Targeting best quality rock
- Realizing consistent results

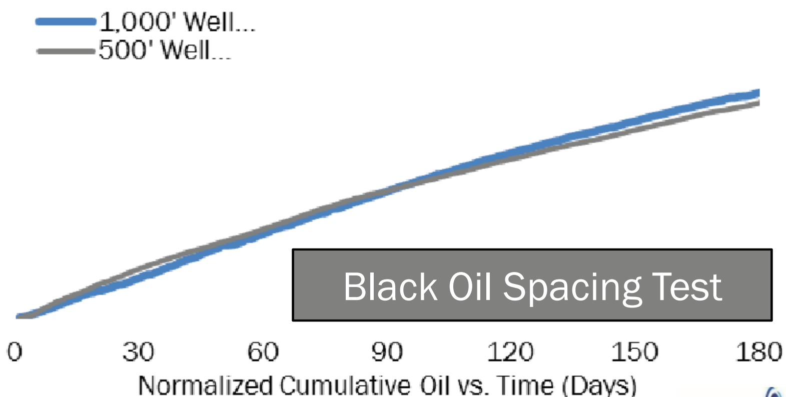
EAGLE FORD DEVELOPMENT

- 2014 Program
  - > 660’ spacing in wet gas areas
  - > 500’ spacing in volatile oil areas
- Infill Evaluation of Black Oil Areas
  - > Down spacing tests in multiple black oil areas
  - > Optimizing on total program NPV
  - > ~1,100 new locations with successful tests









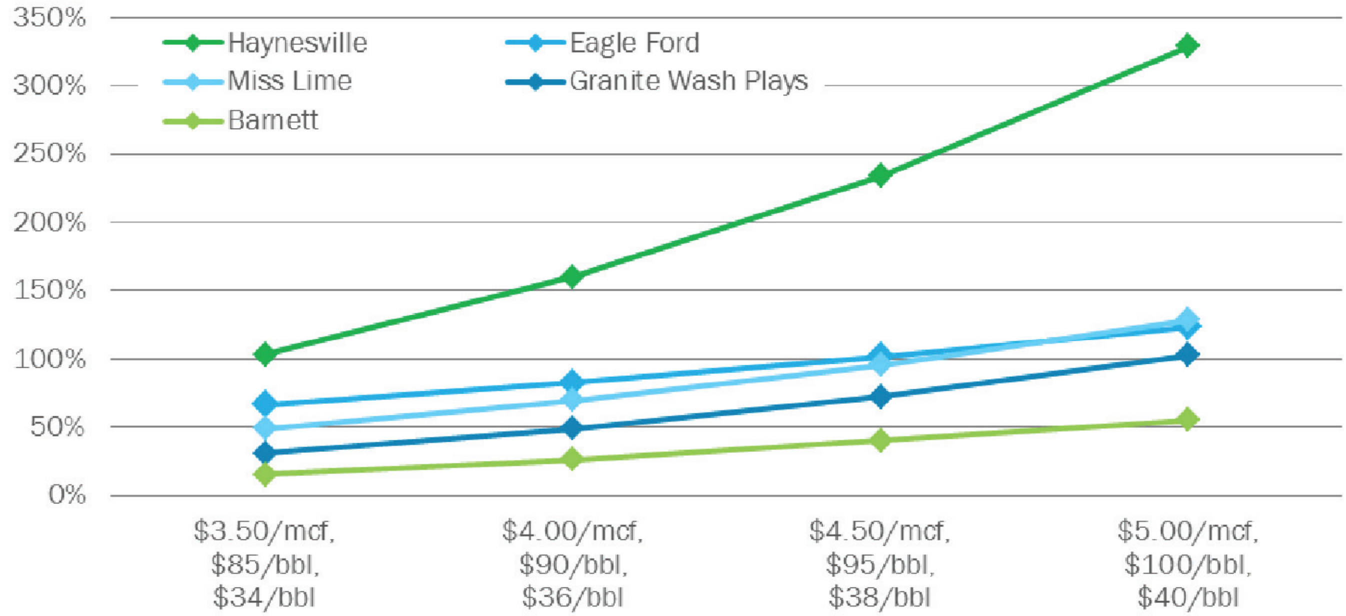
Chesapeake ENERGY

SOUTHERN DIVISION

APPENDIX

SOUTHERN DIVISION UNBURDENED ECONOMICS

Unburdened Rates of Return by Play(1)

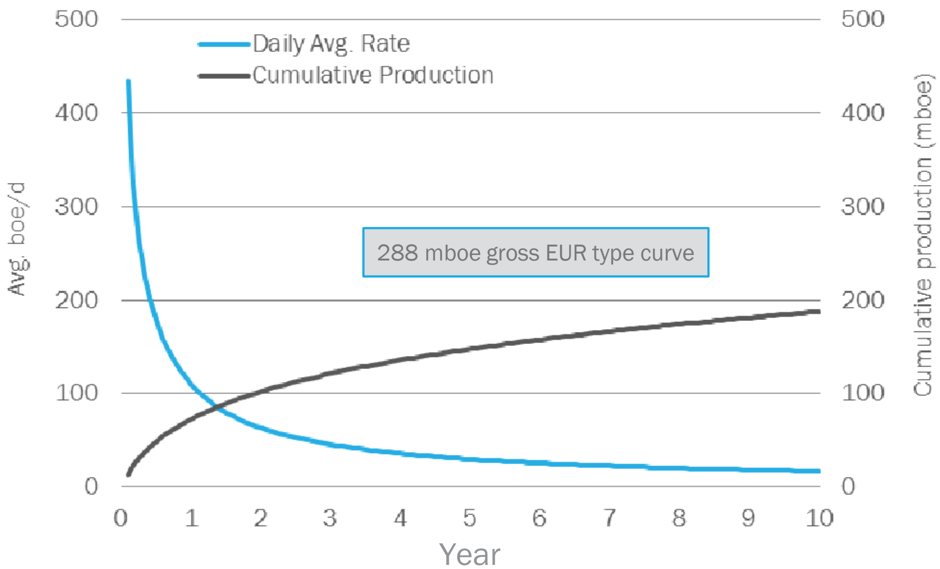


	Haynesville	Eagle Ford	Miss. Lime	Granite Wash Plays	Barnett
2014E Well Cost ($ in mm)	$7.9	$6.6	$3.0	$8.8	$2.5
$3.50/mcf; $85/bbl oil; $34/bbl NGL	103%	67%	49%	31%	15%
$4.00/mcf; $90/bbl oil; $36/bbl NGL	160%	83%	69%	49%	26%
$4.50/mcf; $95/bbl oil; $38/bbl NGL	234%	101%	96%	72%	40%
$5.00/mcf; $100/bbl oil; $40/bbl NGL	329%	123%	128%	103%	55%

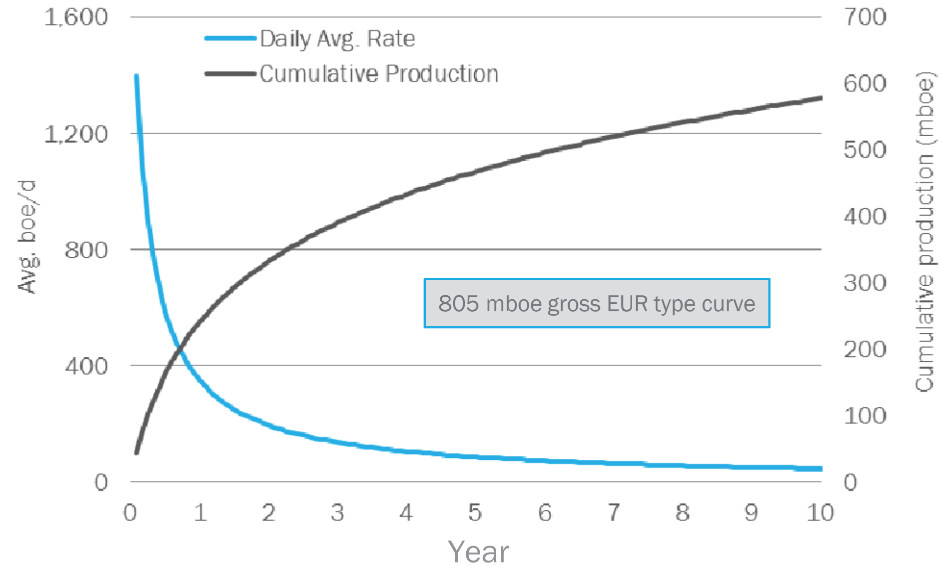
(1) Assumes NYMEX natural gas and oil prices, excludes spud to TIL cycle times

MID-CONTINENT ECONOMICS

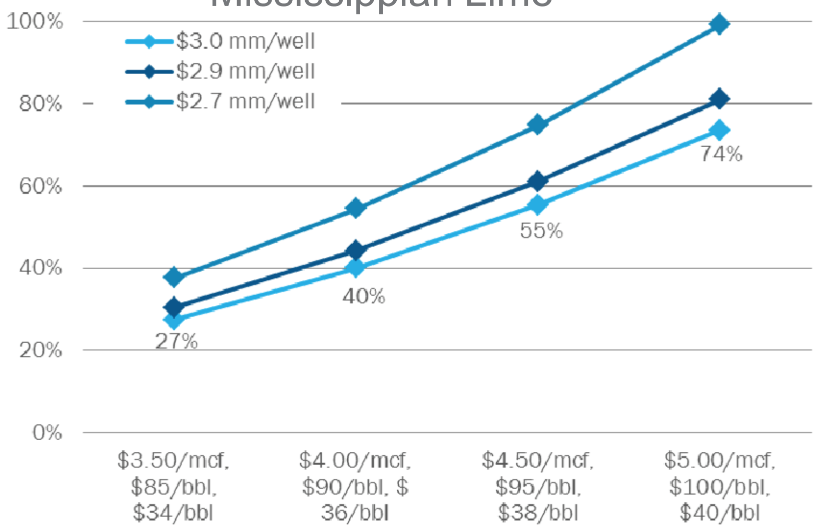
Mississippian Lime



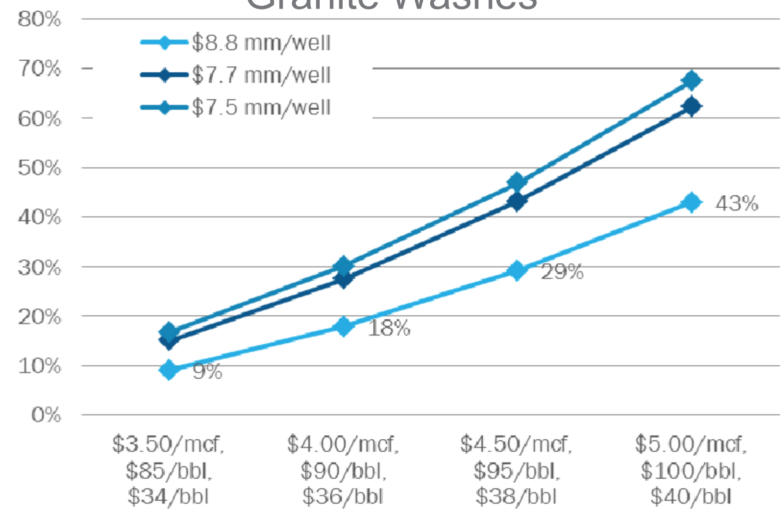
Granite Washes



Mississippian Lime(1)



Granite Washes(1)

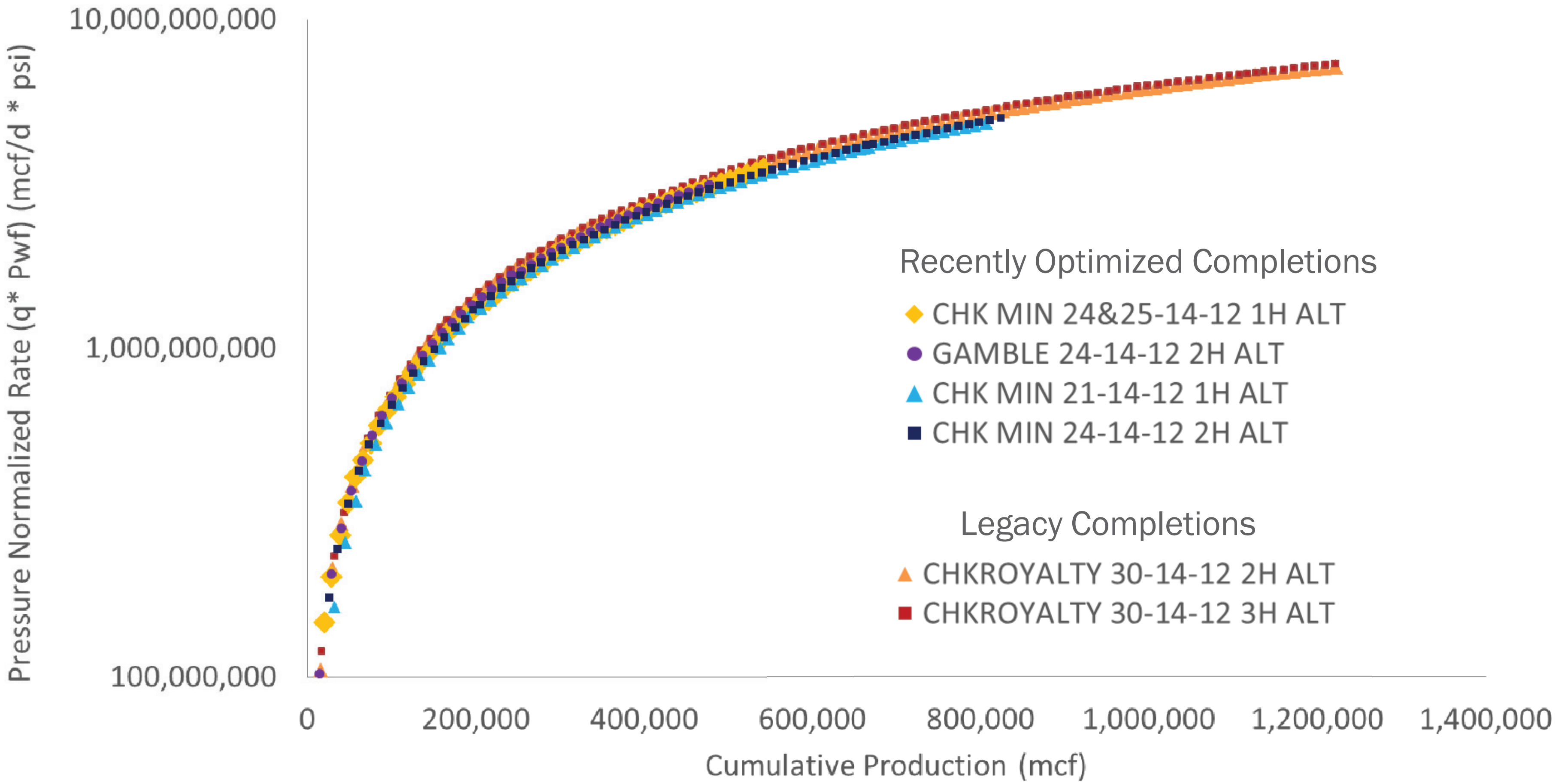


(1) Assumes differentials to NYMEX natural gas and oil prices of ($1.27)/mcf and ($4.05)/bbl for gathering/transportation costs and regional basis differential. Also assumes 50 and 80 and day spud to TIL cycle time delay for Miss. Lime and Granite Wash plays, respectively

Note: type curve and rates of return represent 2014 program

Chesapeake ENERGY

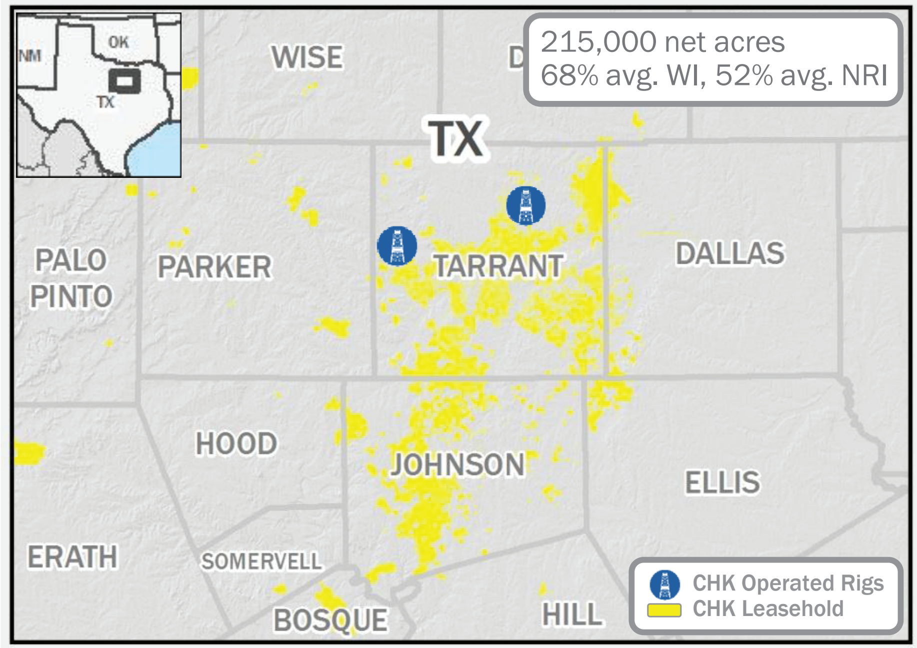
HAYNESVILLE
STIMULATION OPTIMIZATION



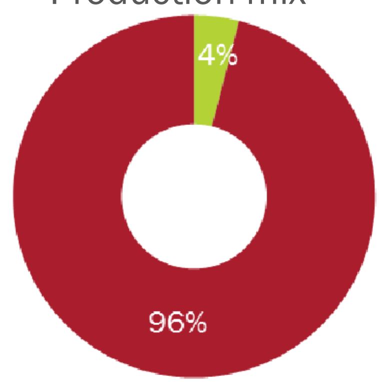
- Stimulation optimization efforts have resulted in no degradation of performance

BARNETT SHALE ASSET OVERVIEW

- ~6 tcfe of net recoverable resources
- Net production of 429 mmcfe/d[1]
- 1 - 2 operated rigs in 2014
- <5% of 2014 estimated E&P capex



Production mix[1]



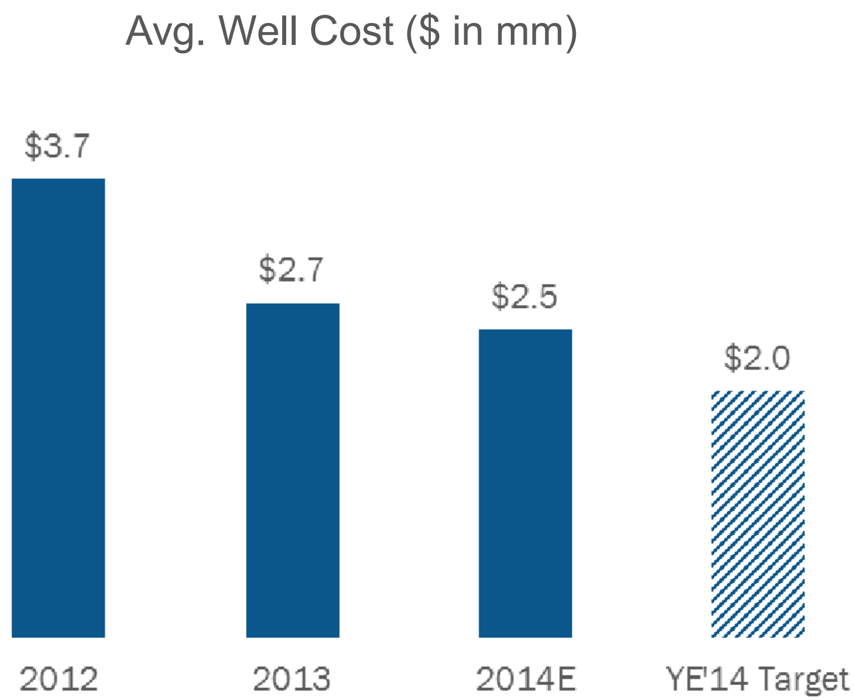
Operated locations[2]

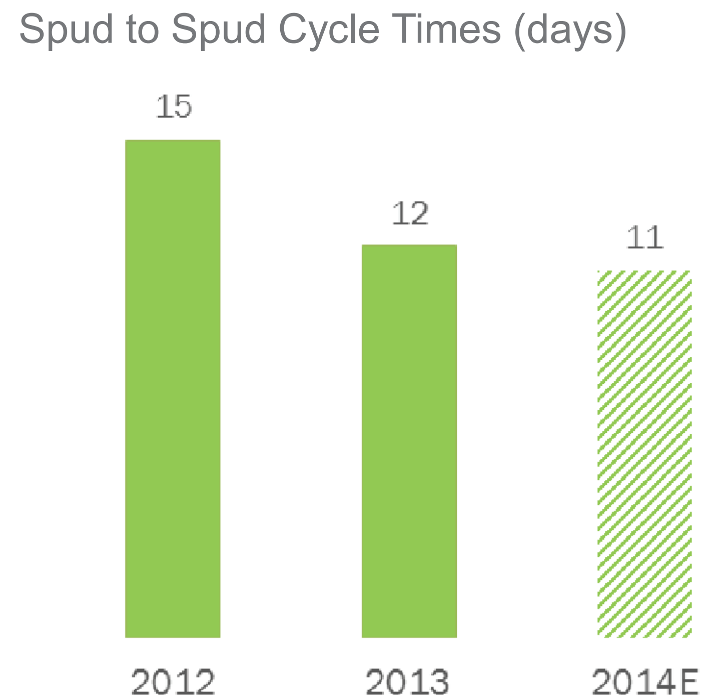
Drilled	2,637
Producing	2,544
Inventory	58
Undrilled	1,700+

(1) 1Q'14 daily average net production
(2) Gross operated locations as of 3/31/2014; drilled locations include plugged and abandoned

Chesapeake ENERGY

BARNETT SHALE
CONTINUOUS IMPROVEMENT

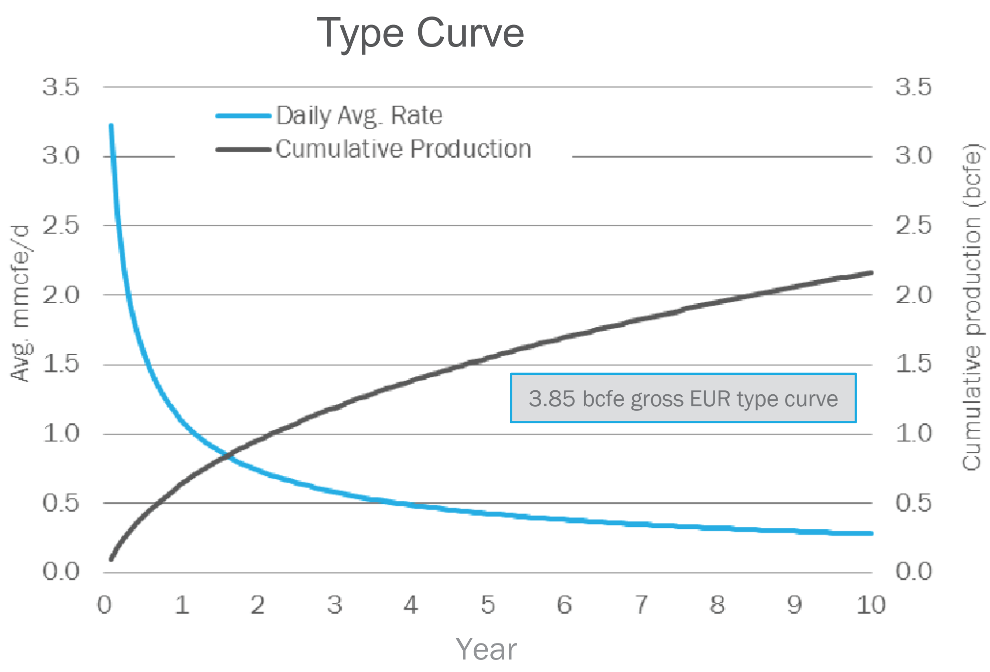


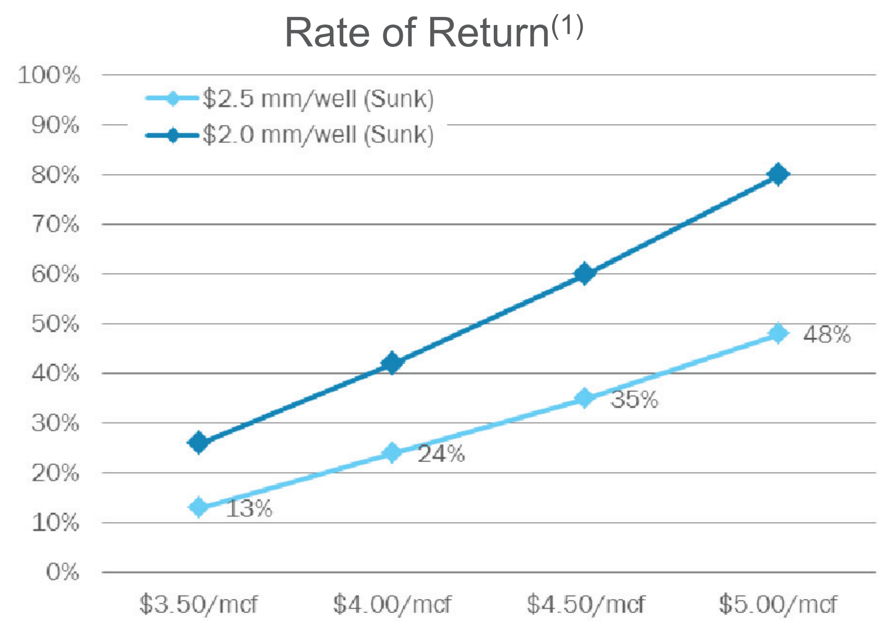


- Targeting year-end D&C cost/well of $2.0 mm
- Targeting spud to TIL cycle time improvement of 50%
- Current avg. drilled lateral length of ~5,500'

100%
Multi-well pad drilling

BARNETT SHALE ECONOMICS



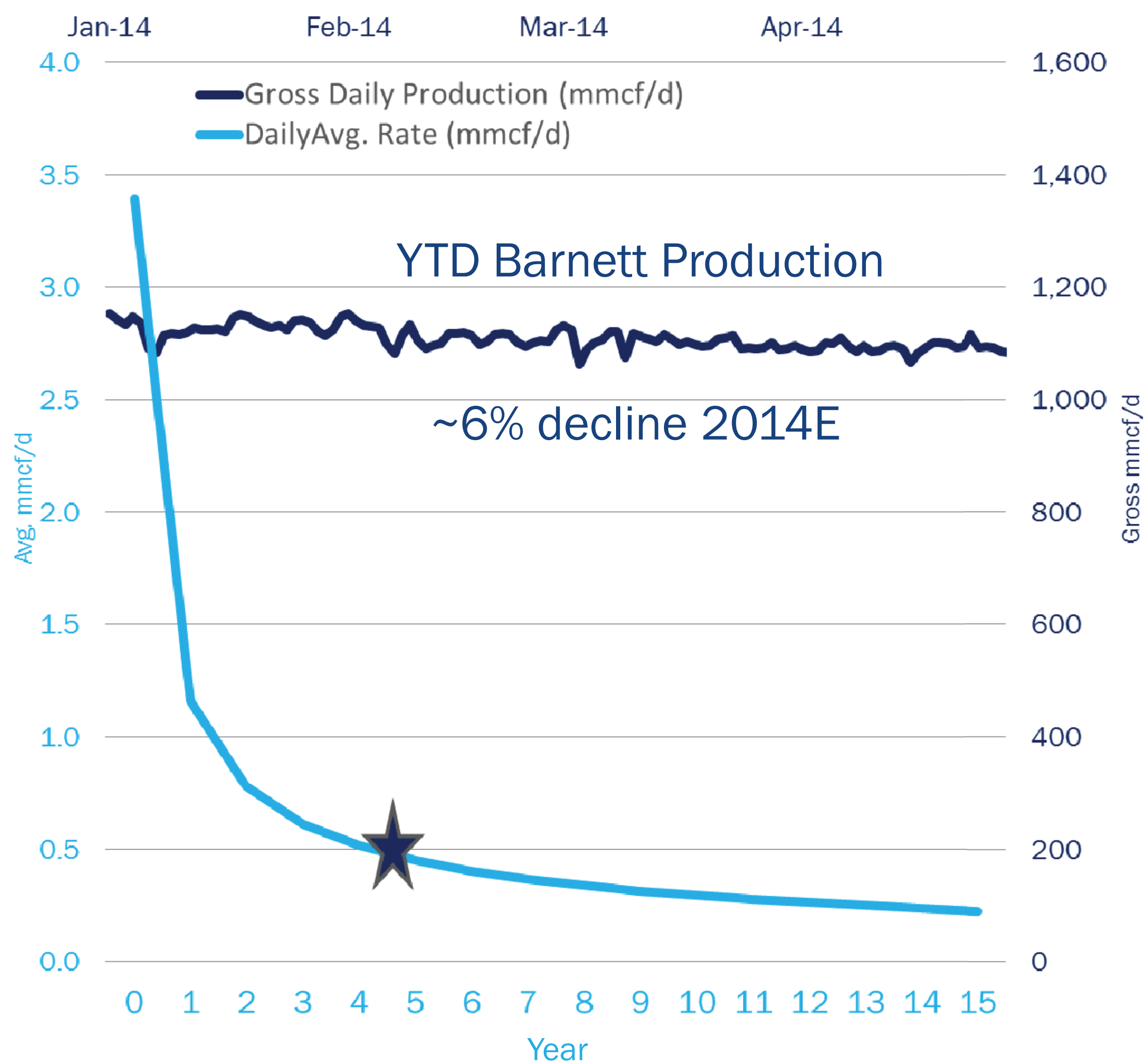


- First month avg: 3.24 mmcfe/d
- Well cost: $2.5 mm and improving
- Unburdened ROR of 24% at $4/$90[(1)]

(1) Assumes midstream volume commitments as a sunk cost. Also assumes 75 day avg. spud to TIL cycle time delay
Note: type curve and rates of return represent 2014 program

BARNETT SHALE PRODUCTION

- Field maturity now entering period of low base decline rate
- Production stable and predictable[(1)]
- ~1.1 gross bcf/d operated production
- VPP contract terminates Fall 2015



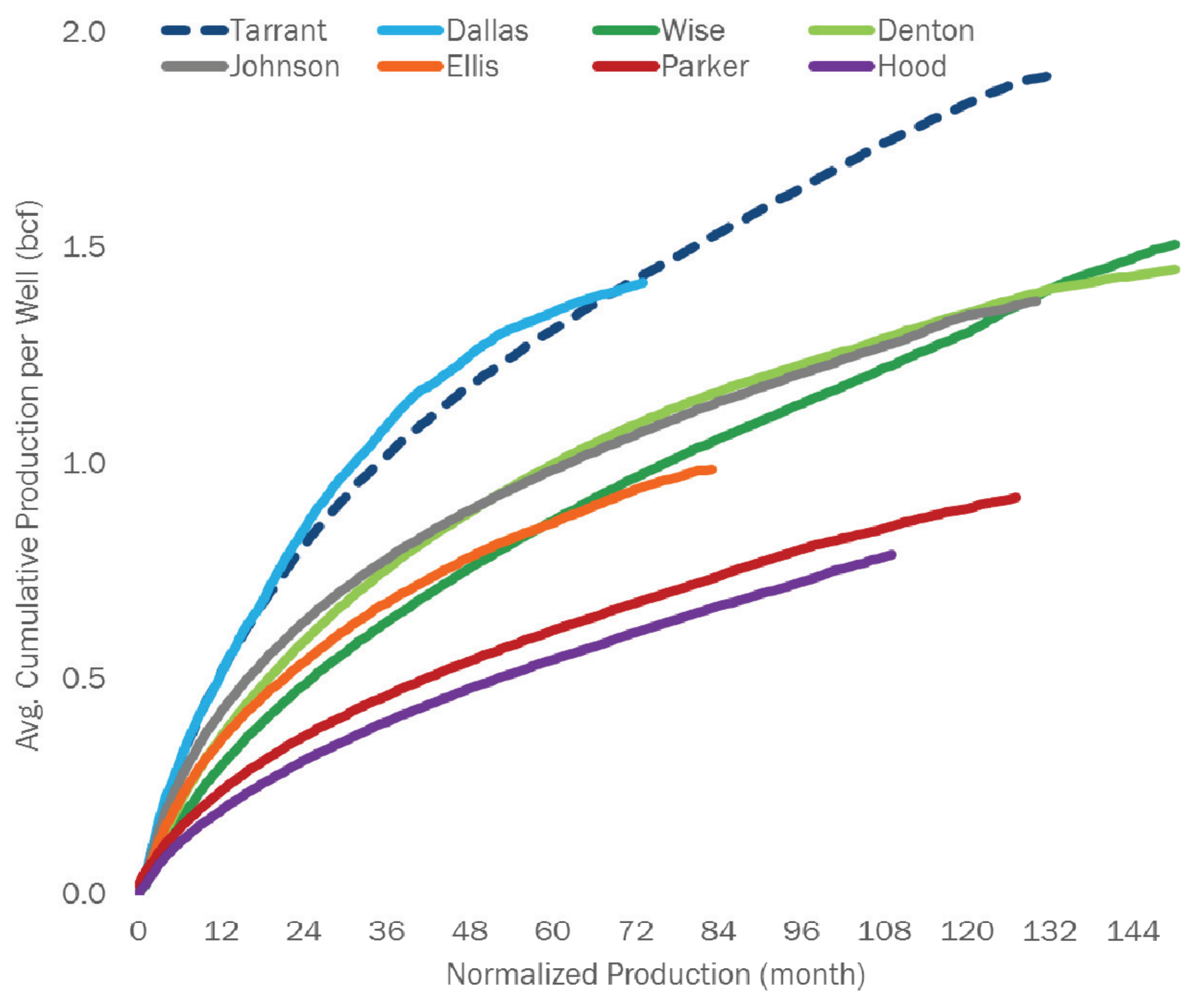
(1) 15 YTD TIL's mitigating overall base decline rate

Chesapeake ENERGY

BARNETT SHALE
BETTER RESULTS IN TARRANT CO.

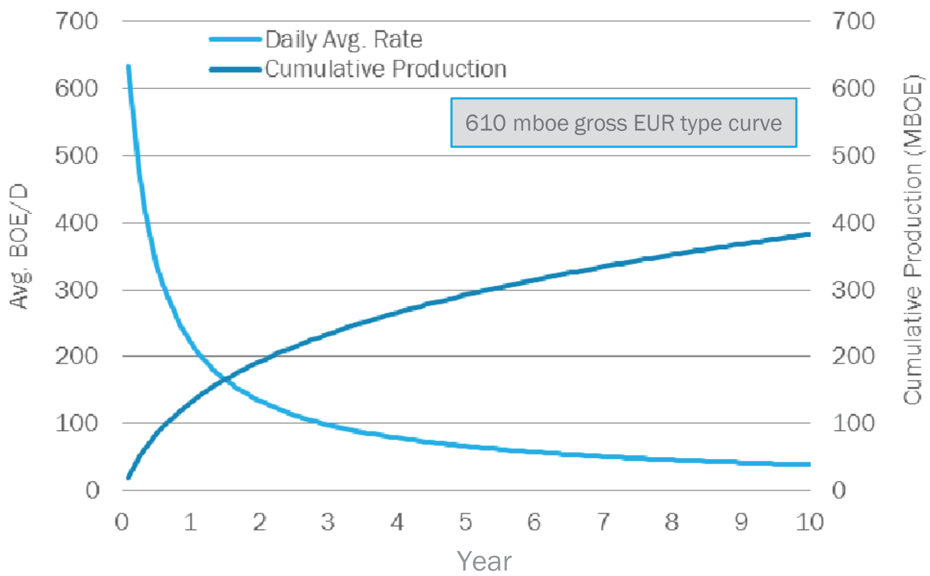
- Improving cash deliverability
- Top performance in Tarrant Co.
- >1,200 remaining locations
- Existing infrastructure to accelerate cycle times
- Improving cost structures

Cumulative Production by County

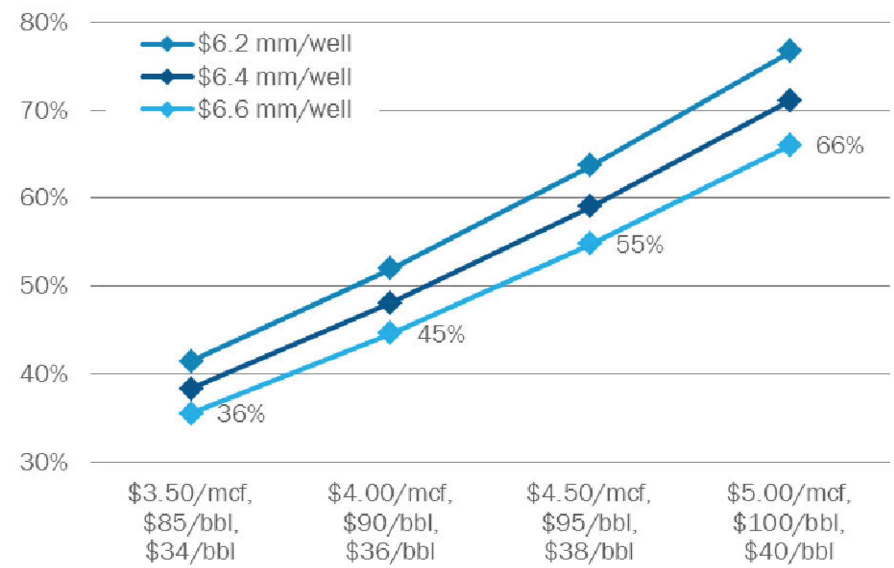


EAGLE FORD ECONOMICS

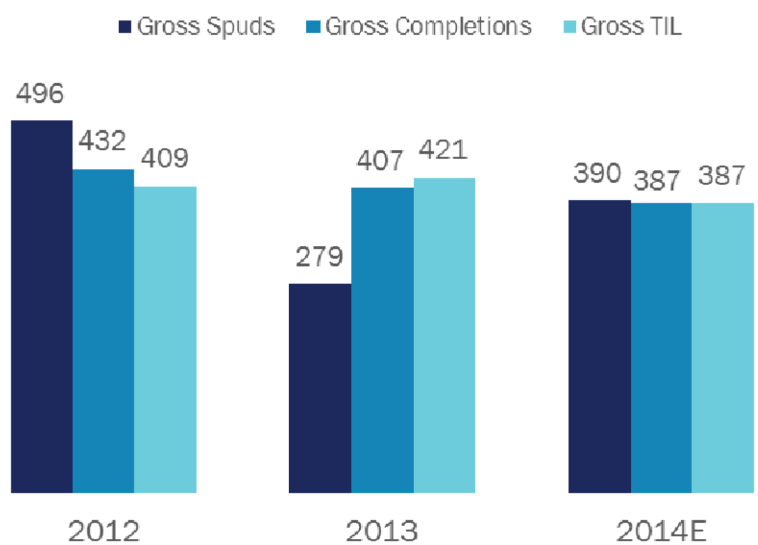
Type Curve



Rate of Return(1)



- First month avg: 635 boe/d
- Well cost: $6.6 mm
- ROR of 45% at $4/$90(1)
- Optimizing ratio of wells TIL vs. spud



(1) Assumes differentials to NYMEX natural gas and oil prices of ($3.10)/mcf and ($3.97)/bbl oil for gathering/transportation costs and regional basis differential. Also assumes 115 day spud to TIL cycle time delay

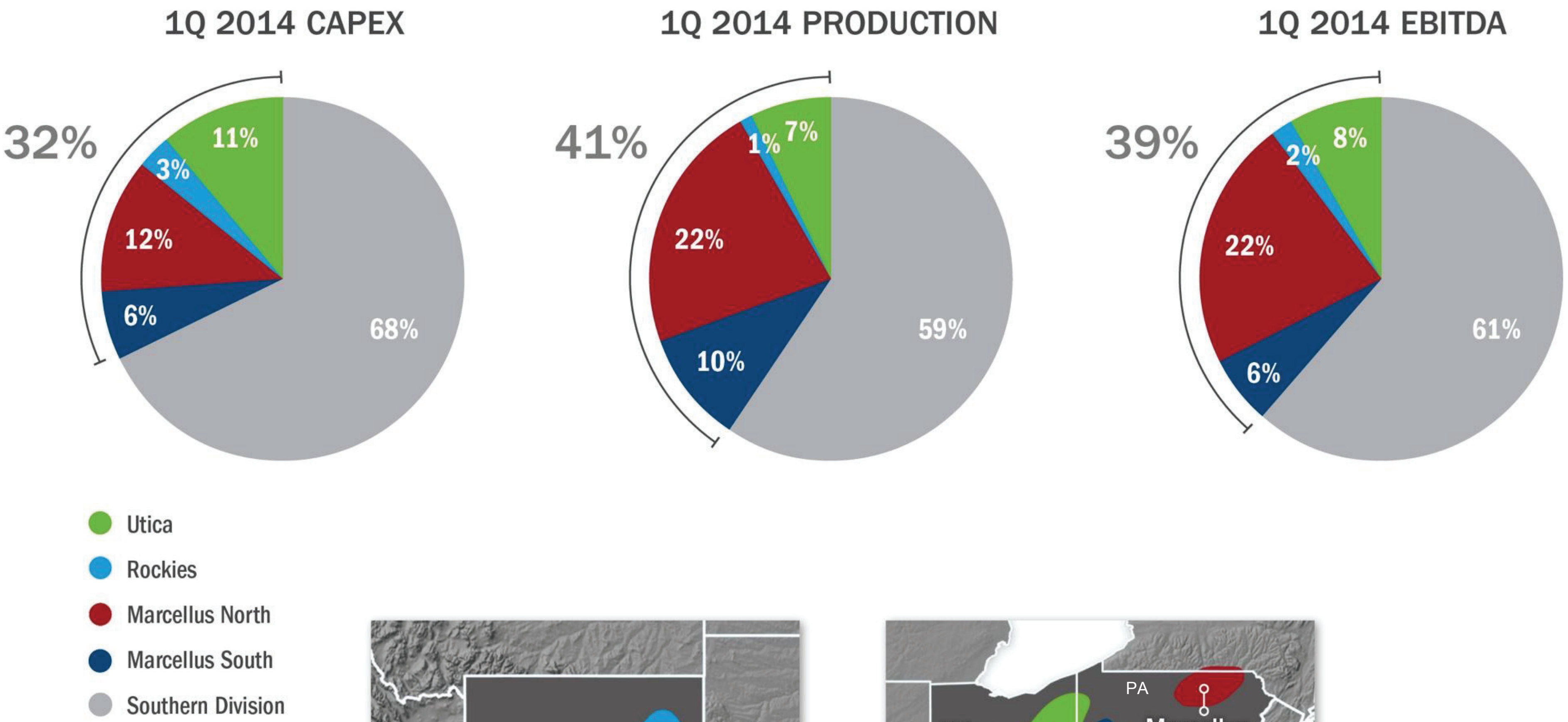
Note: type curve and rates of return represent 2014 program

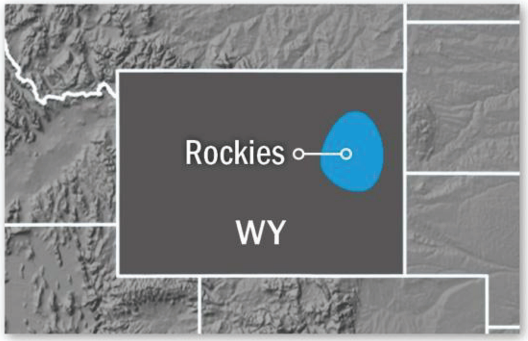
Chesapeake ENERGY

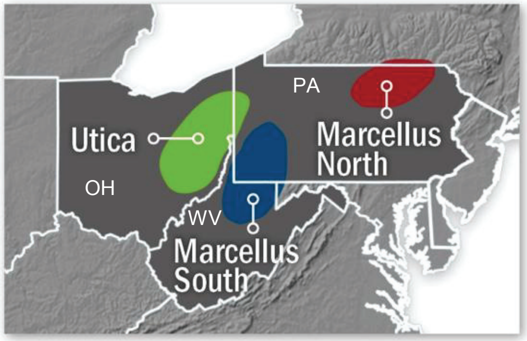
NORTHERN DIVISION

CHRIS DOYLE
SVP - OPERATIONS
NORTHERN DIVISION

NORTHERN DIVISION OVERVIEW







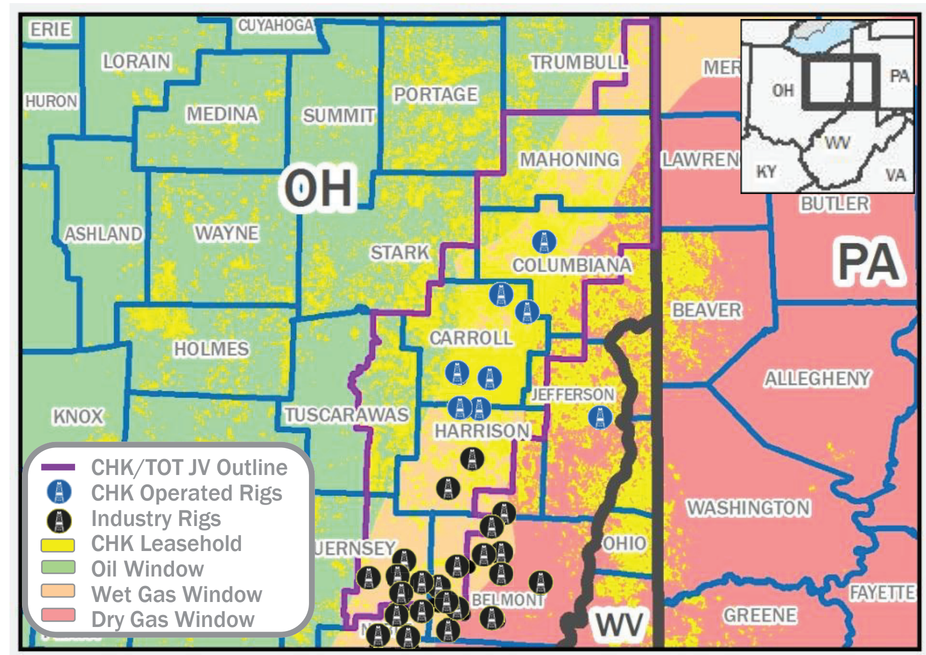
Note: data above assumes E&P capex only, excludes corporate Ebitda adjustment

Chesapeake ENERGY

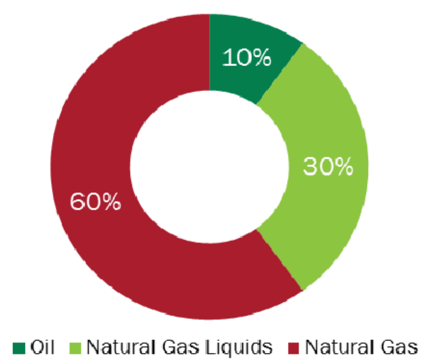
UTICA SHALE
UNVEILING A
WORLD-CLASS ASSET

UTICA
ASSET OVERVIEW

- Over 1 million net acres
  - > 250,000+ net acres in wet gas window
  - > 300,000+ net acres in oil window
  - > 540,000+[1] net acres in dry gas window
- 66% avg. WI, 53% avg. NRI
- 4+ bboe of net recoverable resources
- Net production of 50 mboe/d[2]
- 7 - 9 operated rigs in 2014



Production mix[2]



Operated locations[3]

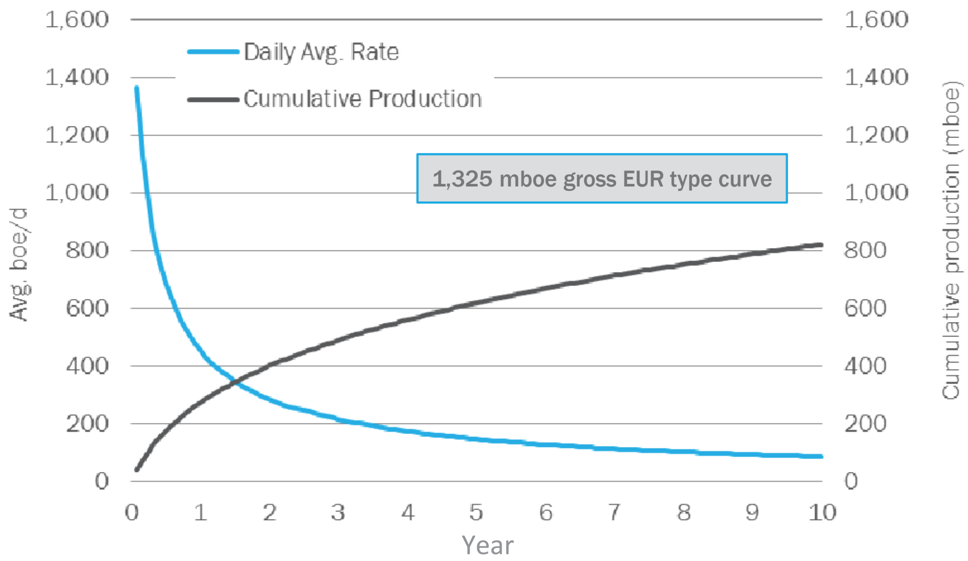
Drilled	485
Producing	274
Inventory	211
Undrilled	5,500+

(1) Utica dry gas acreage includes 165,000+ acres that overlap Southern Marcellus
(2) 1Q'14 daily average net production
(3) Gross operated locations as of 3/31/2014; drilled locations include plugged and abandoned

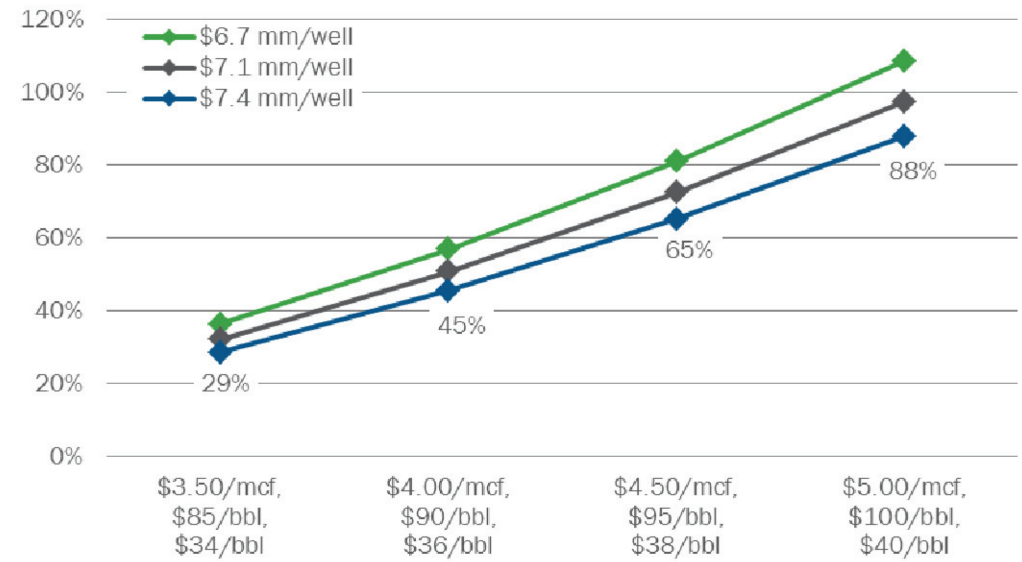
Chesapeake ENERGY

UTICA ECONOMICS

Type Curve(1)



Rate of Return(2)



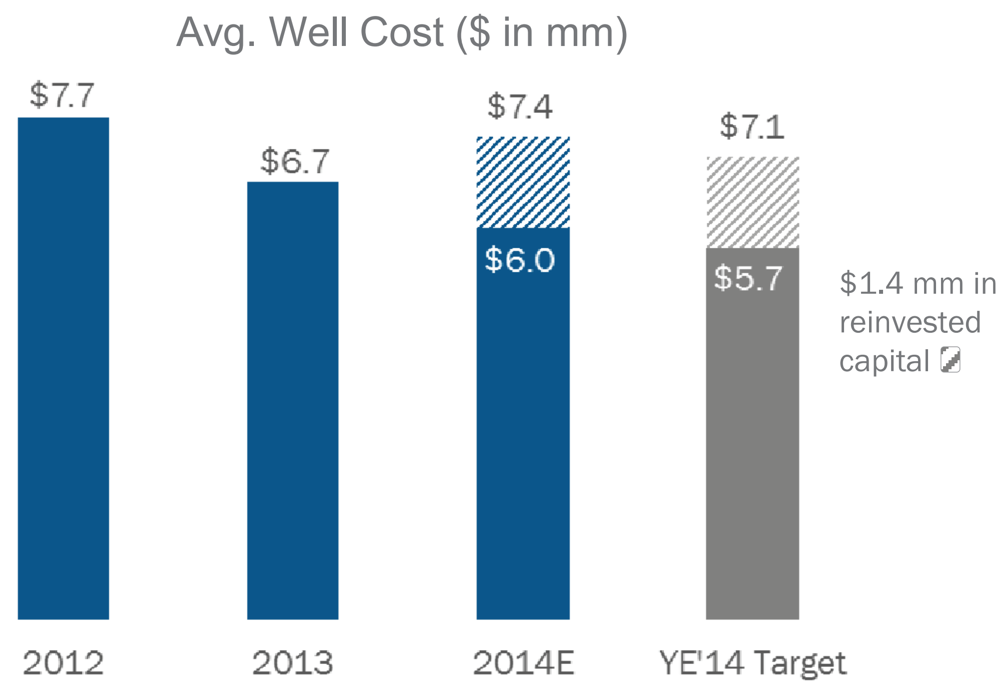
- First month avg: 1,360 boe/d
- Finding cost: $6.71/boe
- Well cost: $7.4 mm
- ROR of 45% at $4/$90/$36(1)

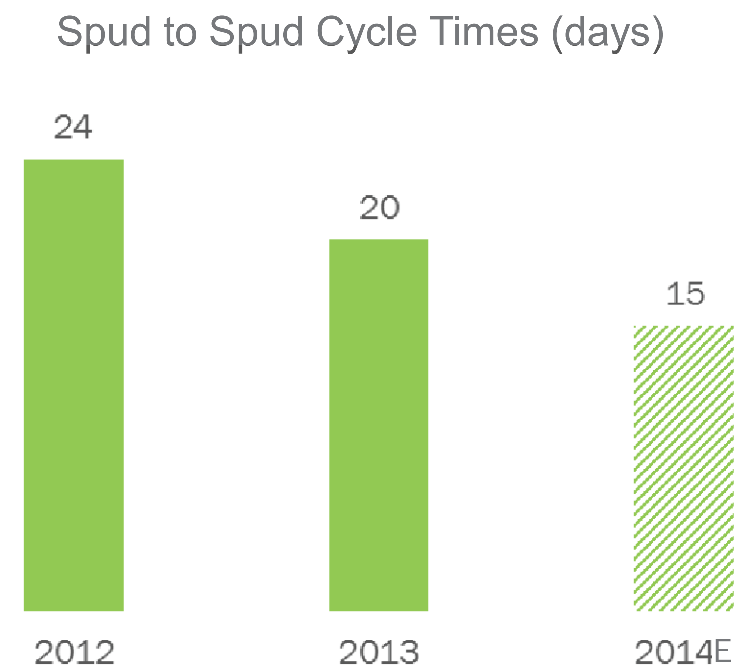
~40%
HBP activity in 2014

>60%
2015 program expected ROR

(1) EUR assumes ethane recovery to meet ATEX commitment
(2) Assumes differentials to NYMEX prices of ($7.00)/bbl oil and ($1.30)/mcf natural gas for gathering/transportation costs and regional basis differentials. Also assumes 185 day avg. spud to TIL cycle time delay
Note: type curve and rates of return represent 2014 wet gas program

UTICA
CONTINUOUS IMPROVEMENT





- Focused on continuous improvement in 2014
  - Avg. lateral length >6,000 ft. and 22 frac stages
  - >15% increase in lateral length
  - >50% increase in frac stages

2.2 miles

Record for longest useable lateral drilled by CHK (12,106' in 20 days)

80%

ROR on incremental $1.4 mm investment in completion optimization

Chesapeake ENERGY

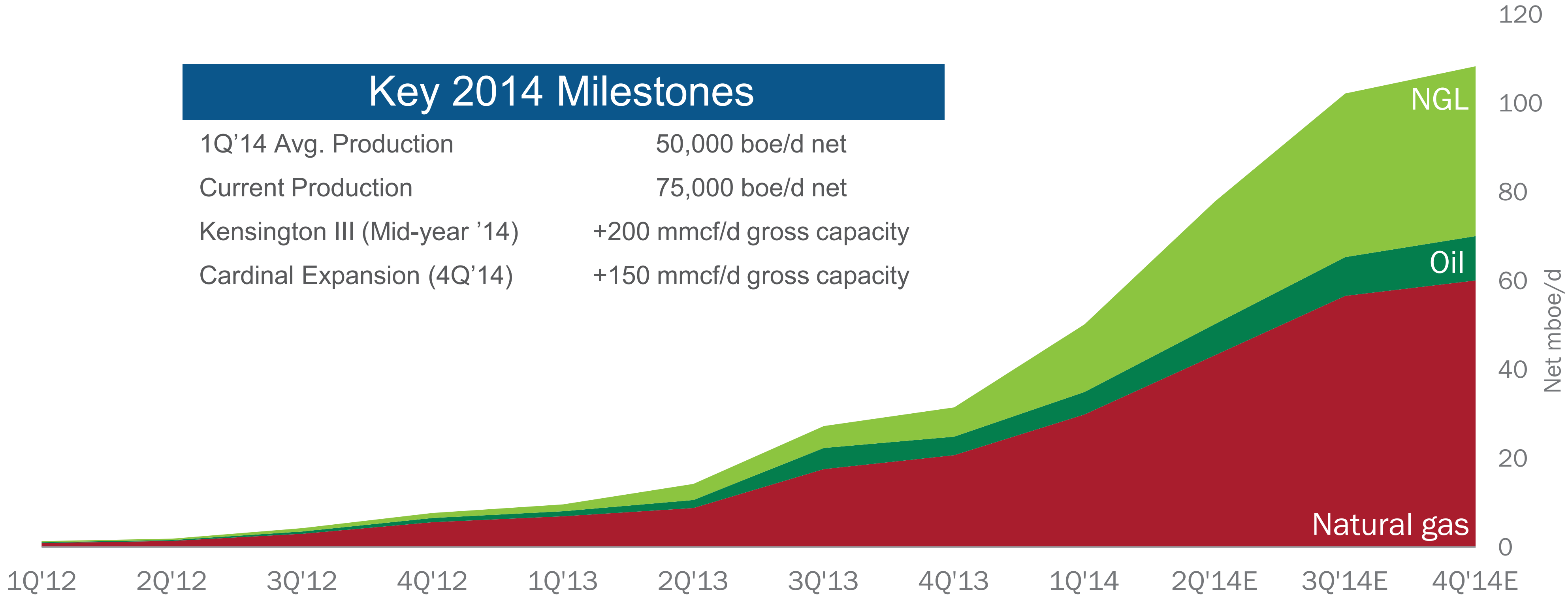
UTICA
PRODUCTION RAMP

>400%
YOY Production Growth
(2012 to 2013)

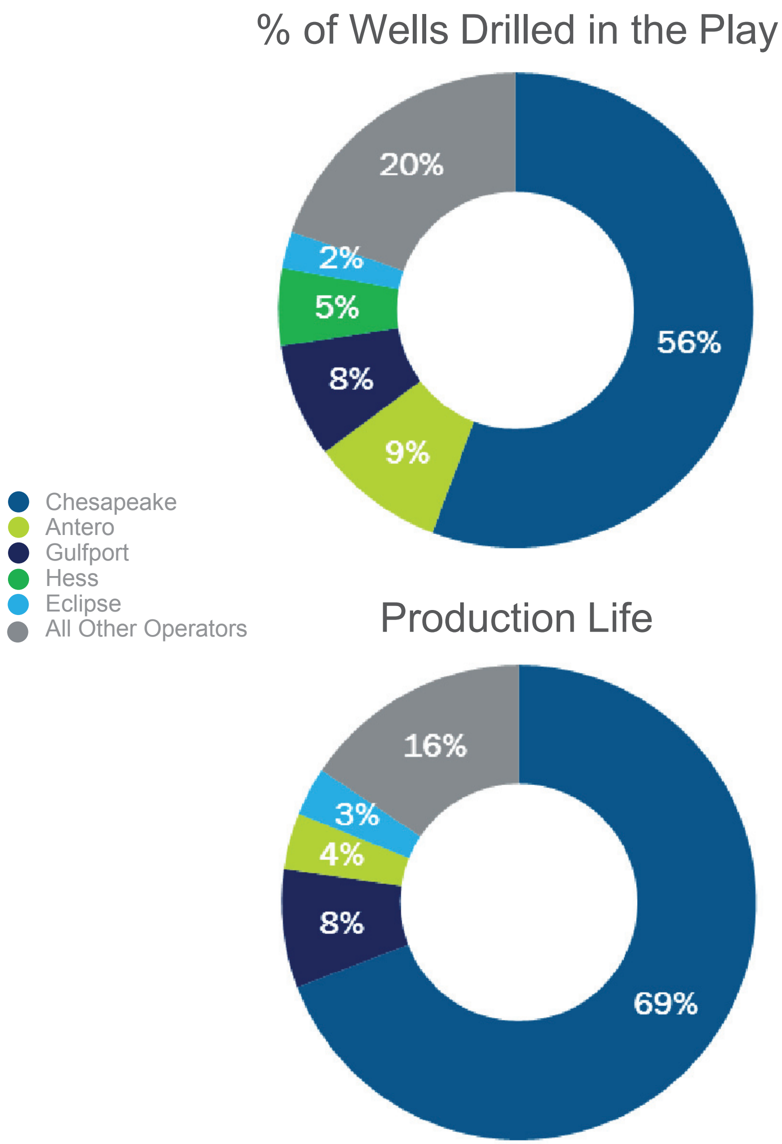
>300%
YOY Production Growth
(2013 to 2014E)

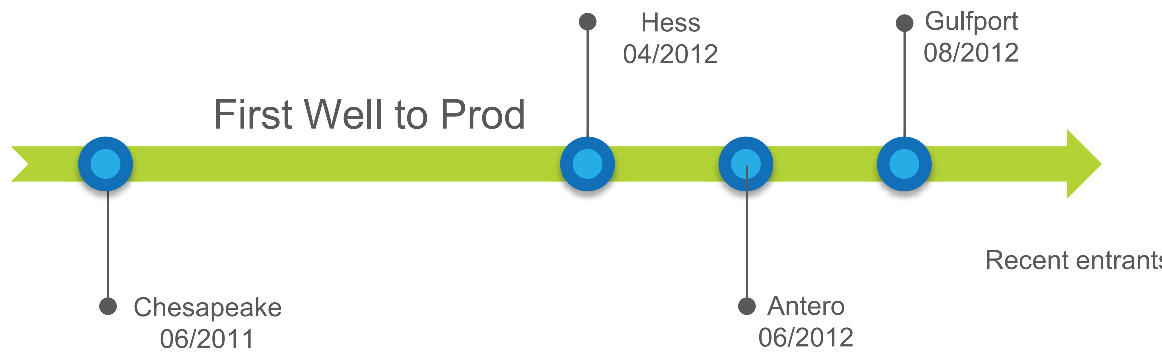
30 - 60%
YOY Production Growth
(2014E to 2015E)

Key 2014 Milestones	
1Q'14 Avg. Production	50,000 boe/d net
Current Production	75,000 boe/d net
Kensington III (Mid-year '14)	+200 mmcf/d gross capacity
Cardinal Expansion (4Q'14)	+150 mmcf/d gross capacity



UTICA
BEST-IN-CLASS KNOWLEDGE





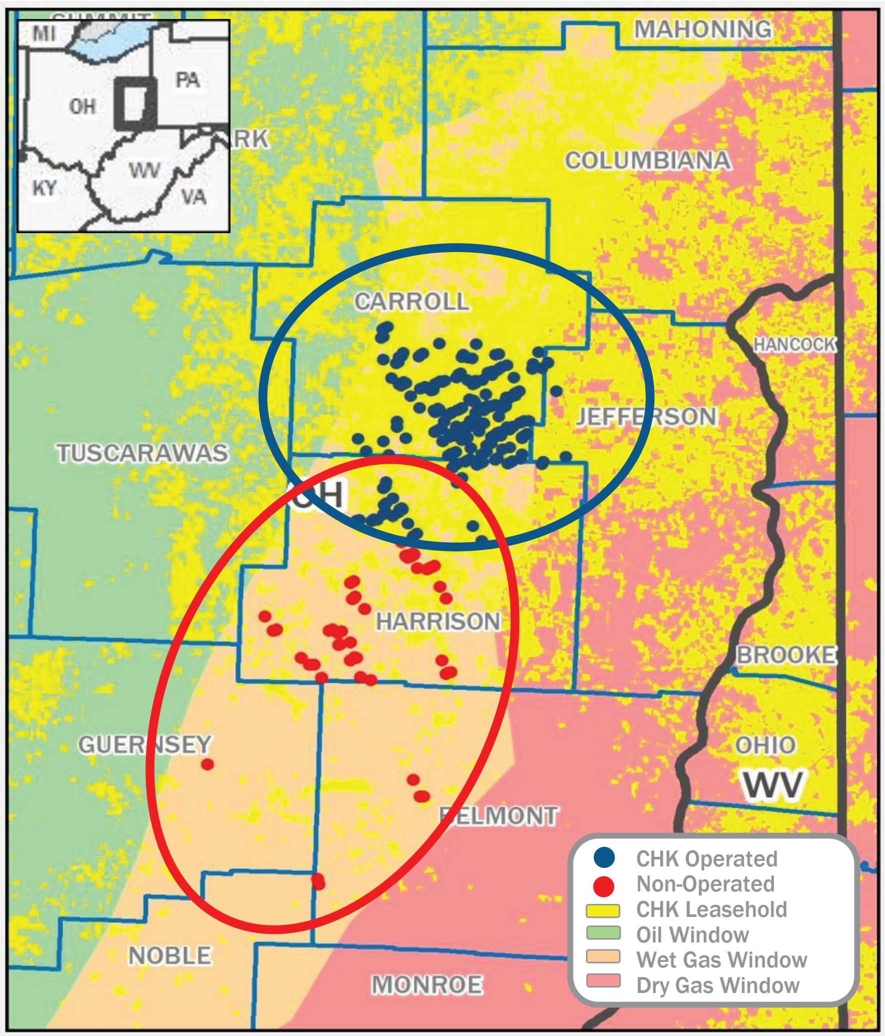
>5,300'
Core to understand reservoir flow and optimize completions

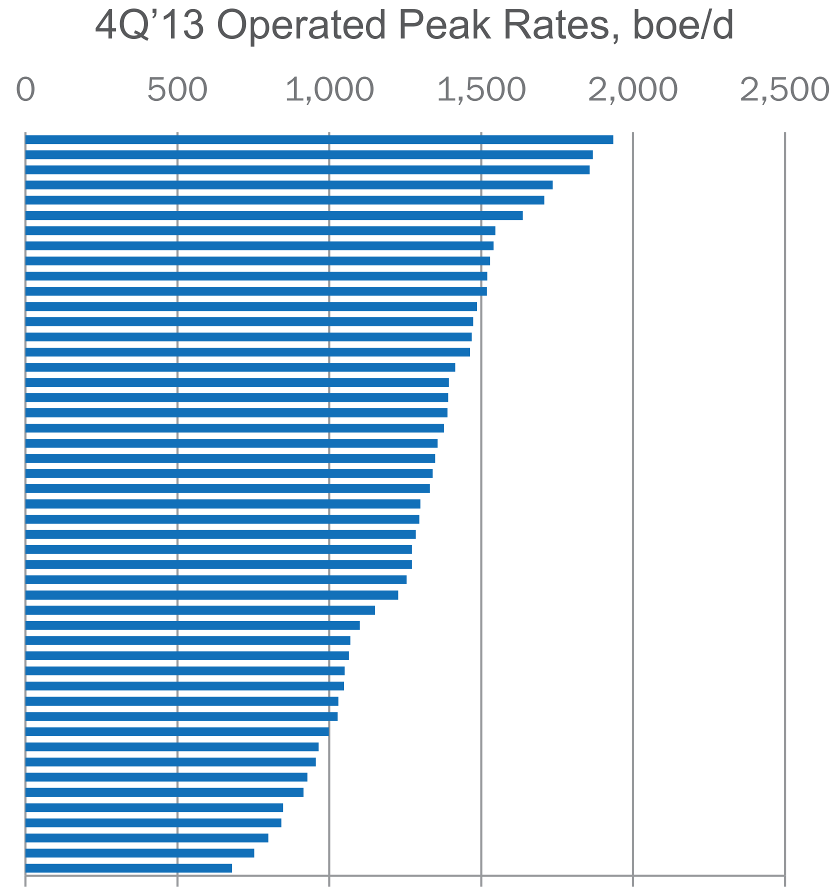
>600 mi^2
3D seismic to understand structure and optimize lateral placement

Extensive experience, data, and knowledge leads to better investment decisions

Source: Ohio DNR / public data as of 3/31/2014

UTICA WET
RECENT WELL RESULTS





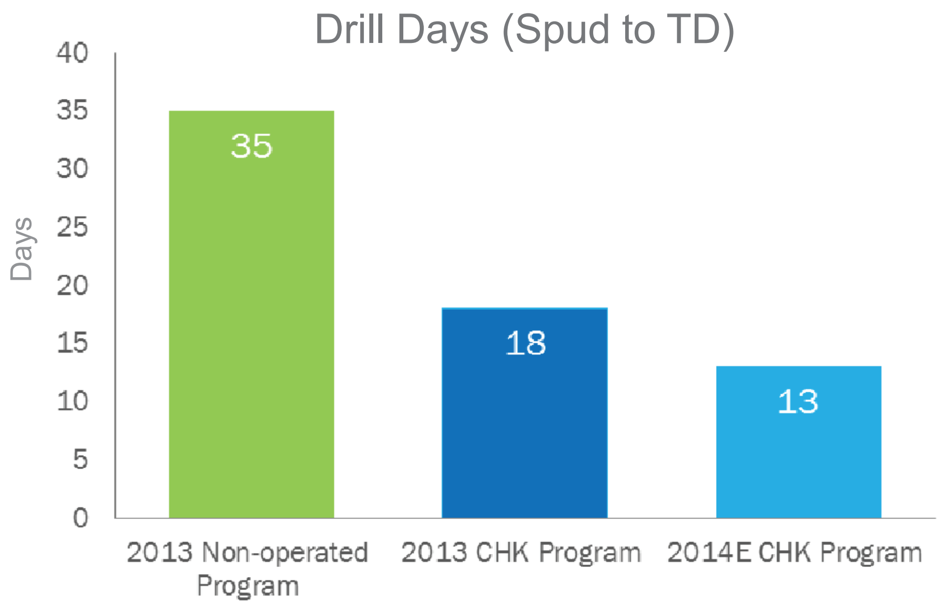
1,280 boe/d
Average peak rate of 4Q '13 Operated (49 wells)

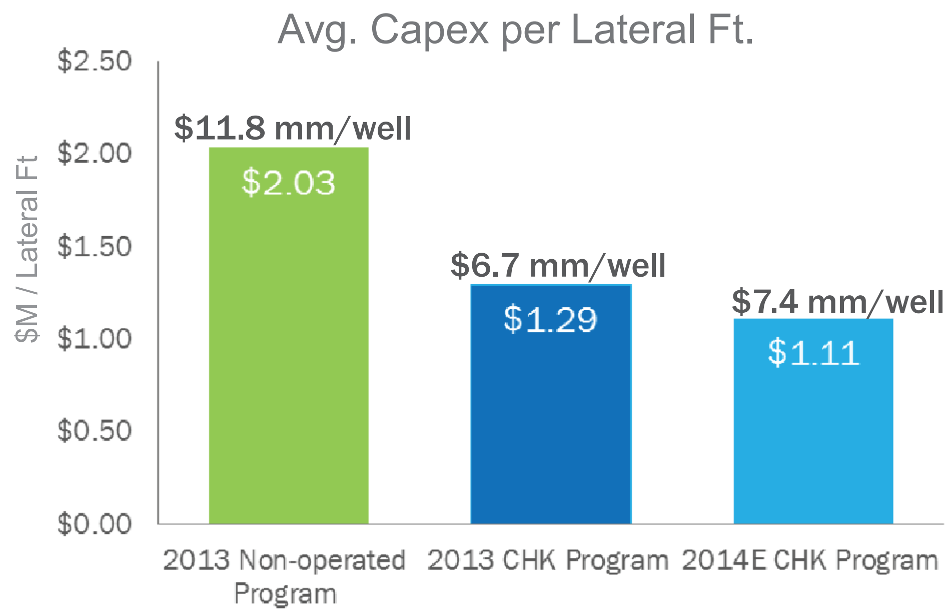
1,290 boe/d
Average peak rate of 2013 Non-Operated (26 wells)

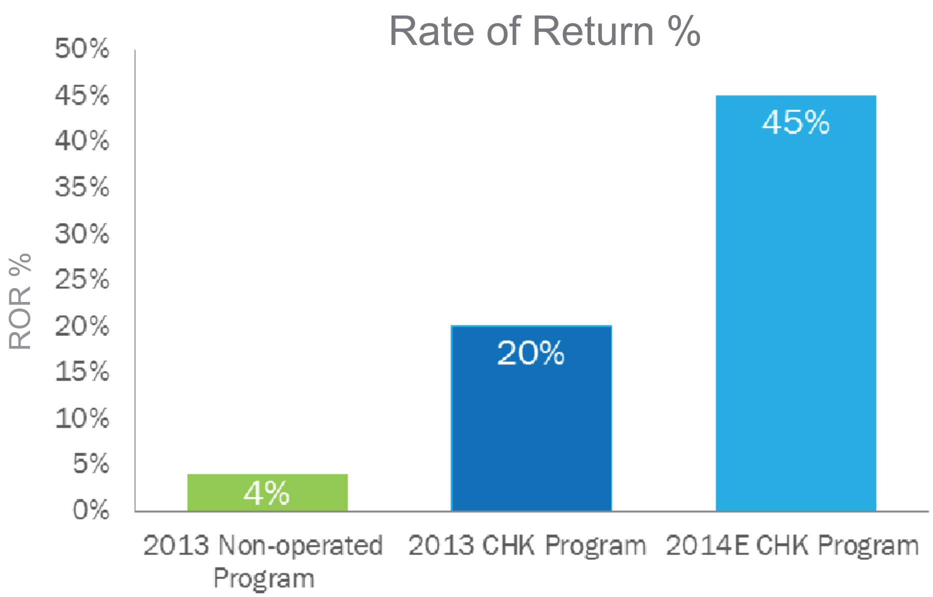
Note: 26 of the 49 non-operated wells in which CHK has a working interest included in peak rate comparison; all other wells are not producing

Chesapeake ENERGY

UTICA WET
BEST-IN-CLASS RESULTS





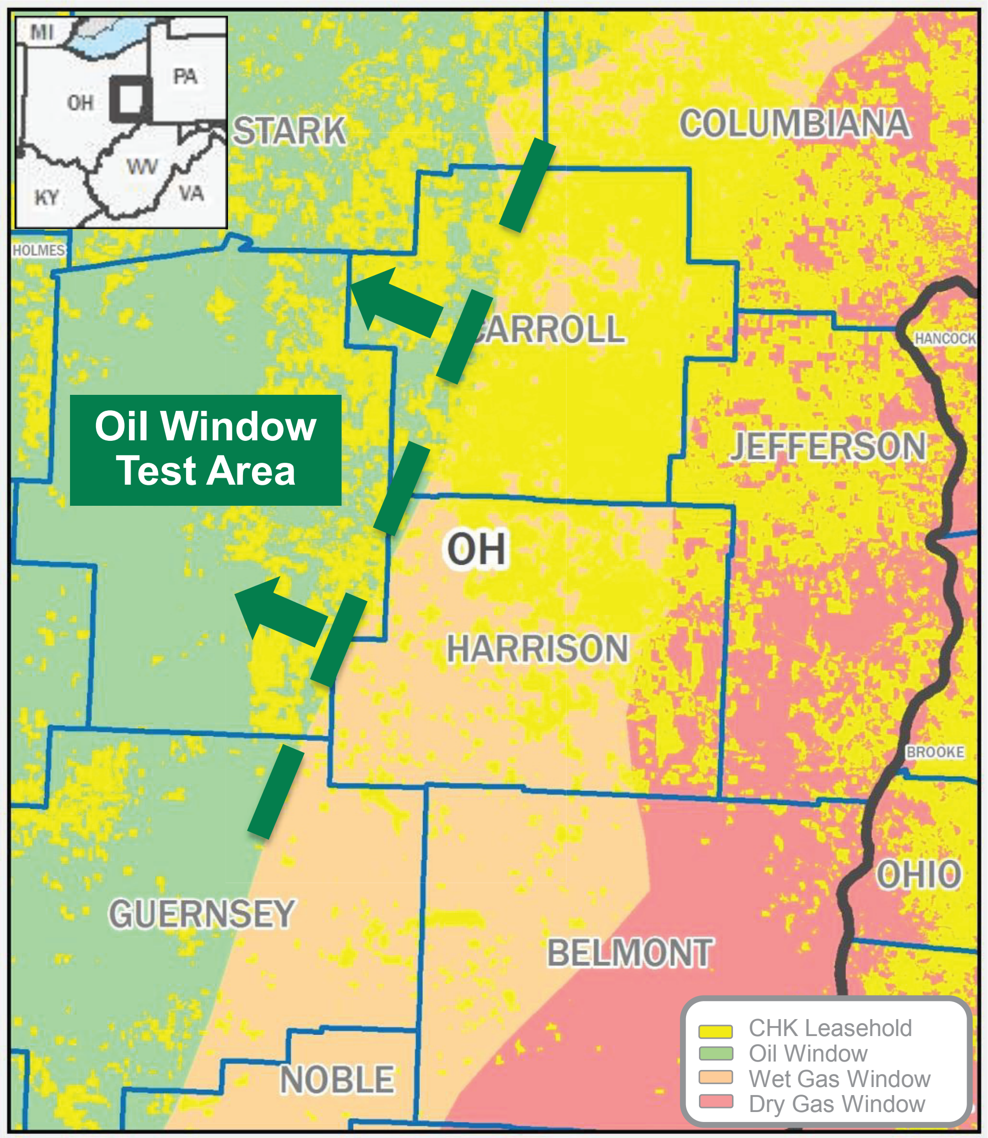


- Extensive basin knowledge through non-op position (average of ~7% WI)
- Aggressively pursuing acreage trades to minimize non-op financial exposure

Note: non-operated data based on 49 wells where CHK has a working interest. Includes Gulfport, Hess, AEP and Eclipse.
Wells with insufficient production history excluded from ROR comparison.

Chesapeake ENERGY

UTICA
UNLOCKING THE OIL WINDOW



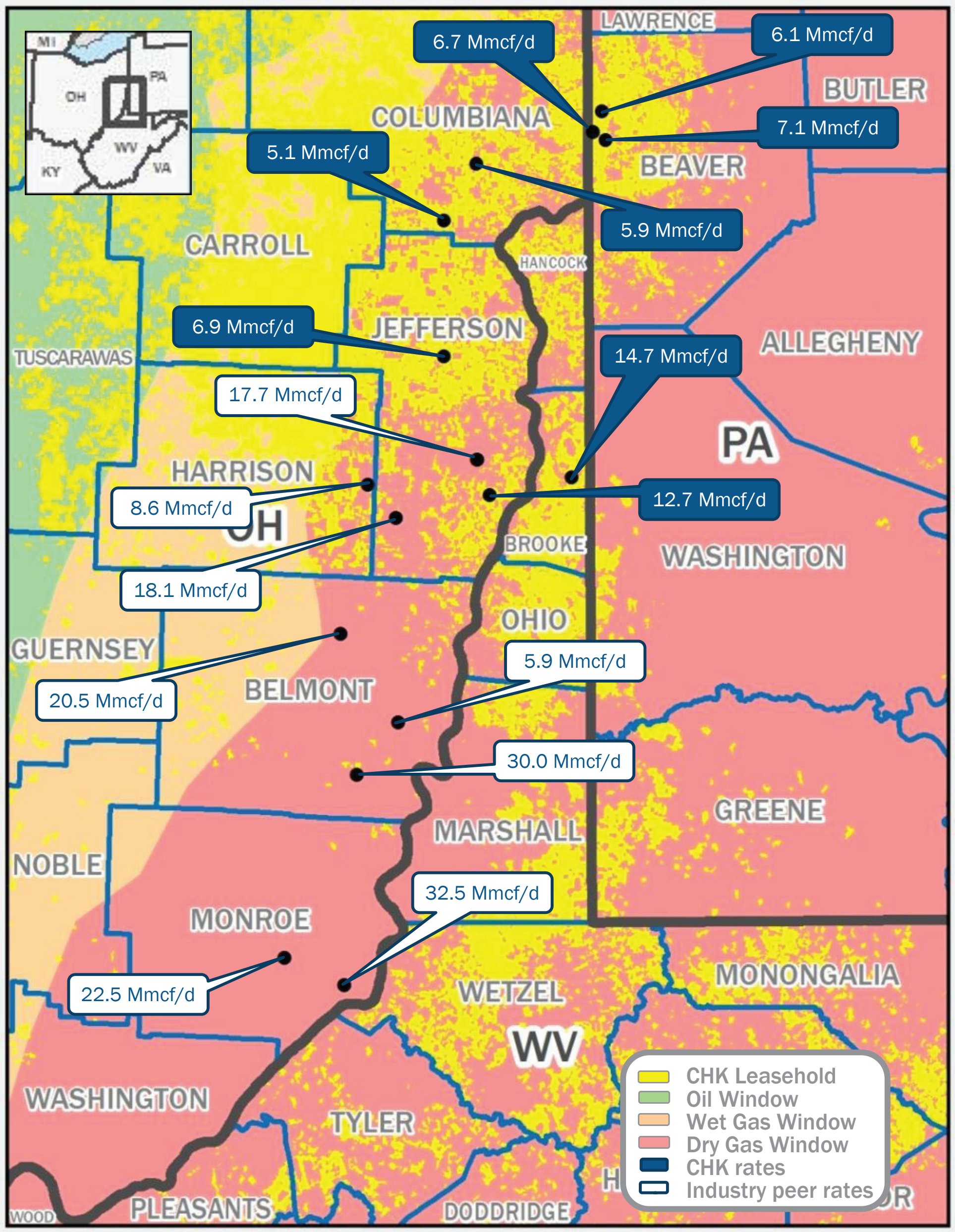
>500 barrels oil
Recent oil IPs
(old completion design)

>1,000 boe/d
Recent full-stream IPs
(old completion design)

- Leveraging proprietary Reservoir Technology Center (RTC)
- Optimizing lateral placement
- Modifying fluid chemistry, volumes, and frac geometries

Chesapeake ENERGY

UTICA OPPORTUNITIES DRY POTENTIAL



Note: Chesapeake peak rates based on old frac design during initial acreage capture

>330,000 acres

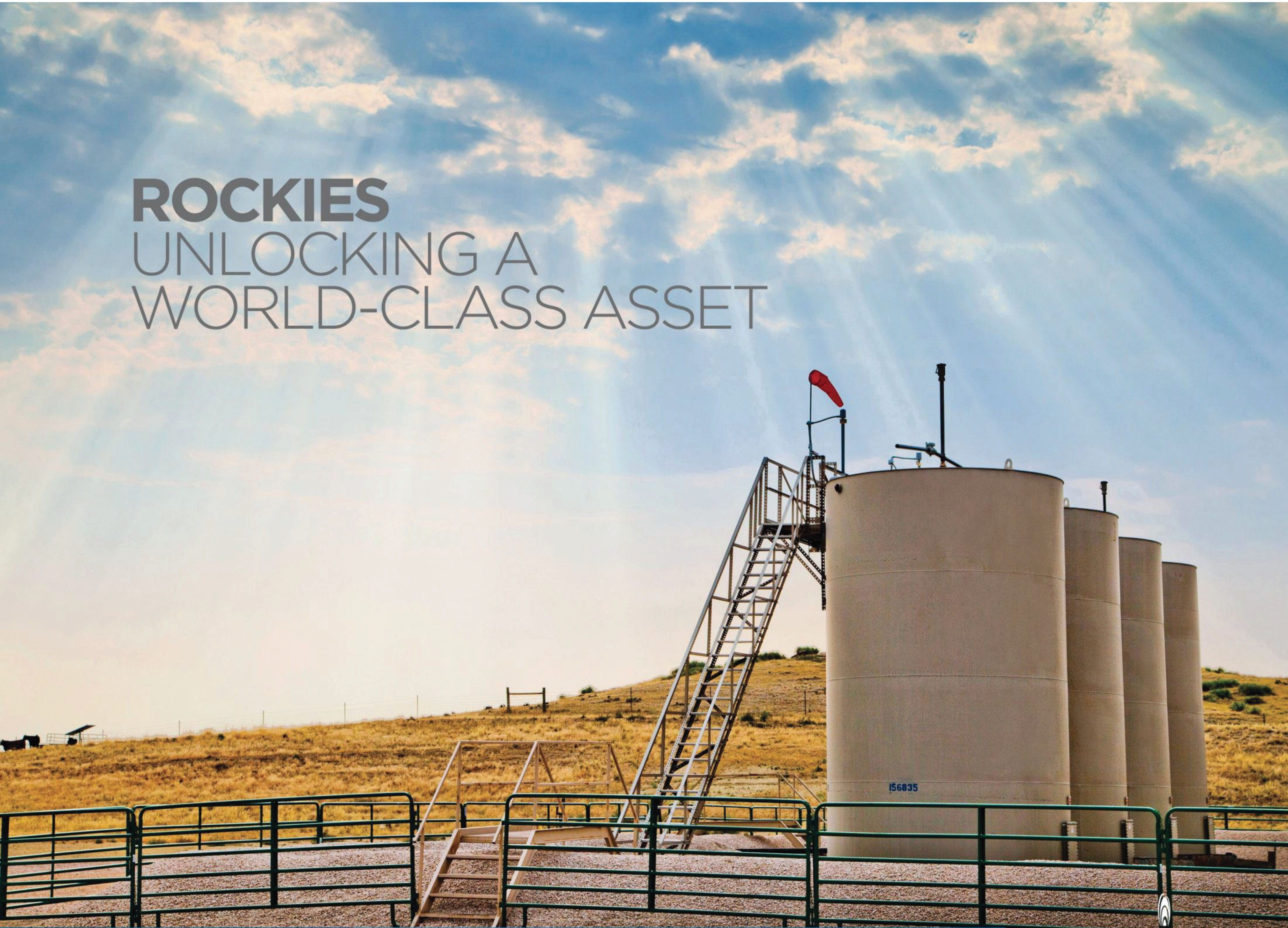
Net, dry gas acres in Jefferson County, OH and W. Virginia

$4 - $7 billion

Implied value based on recent transactions

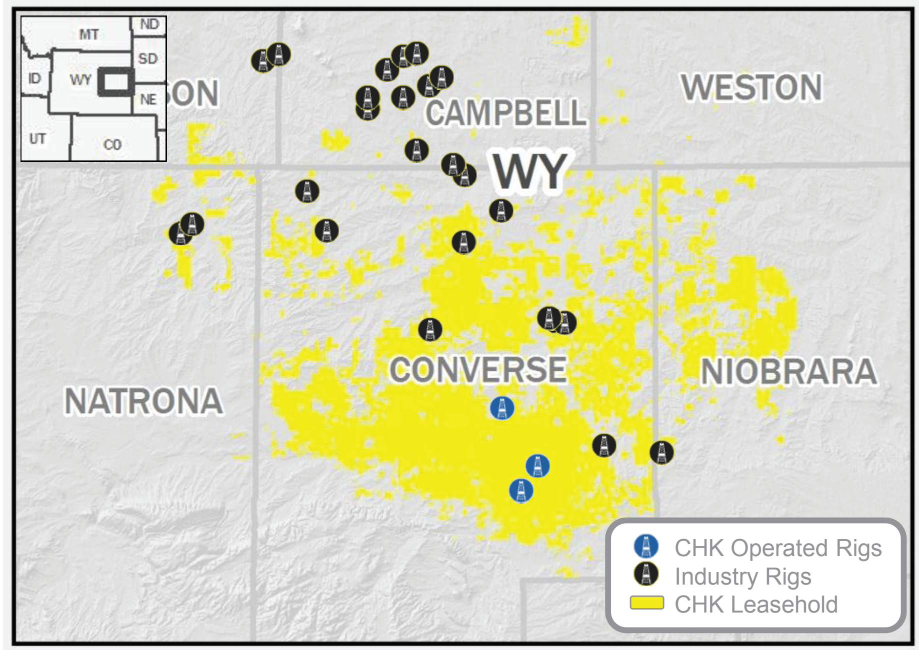
- 2,000+ potential locations
- Expect 10+ bcfe EURs
- 2014 delineation
  - > Test in Wetzel County, WV
  - > Results expected 3Q'14

ROCKIES
UNLOCKING A WORLD-CLASS ASSET

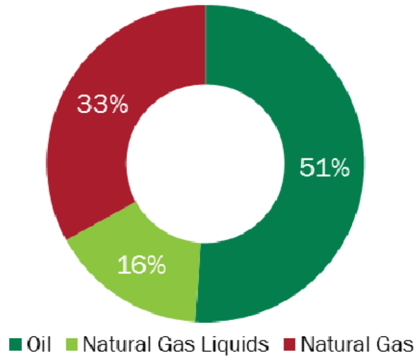


POWDER RIVER BASIN NIOBRARA ASSET OVERVIEW

- >450 mmboe of net recoverable resources
- 320,000+ net acres
  - 38% avg. WI, 30% avg. NRI
- Net production of ~9 mboe/d(1)
- Three operated rigs in 2014
- Buckinghorse Plant (4Q'14) to add 120 mmcf/d processing capacity



Production mix(1)



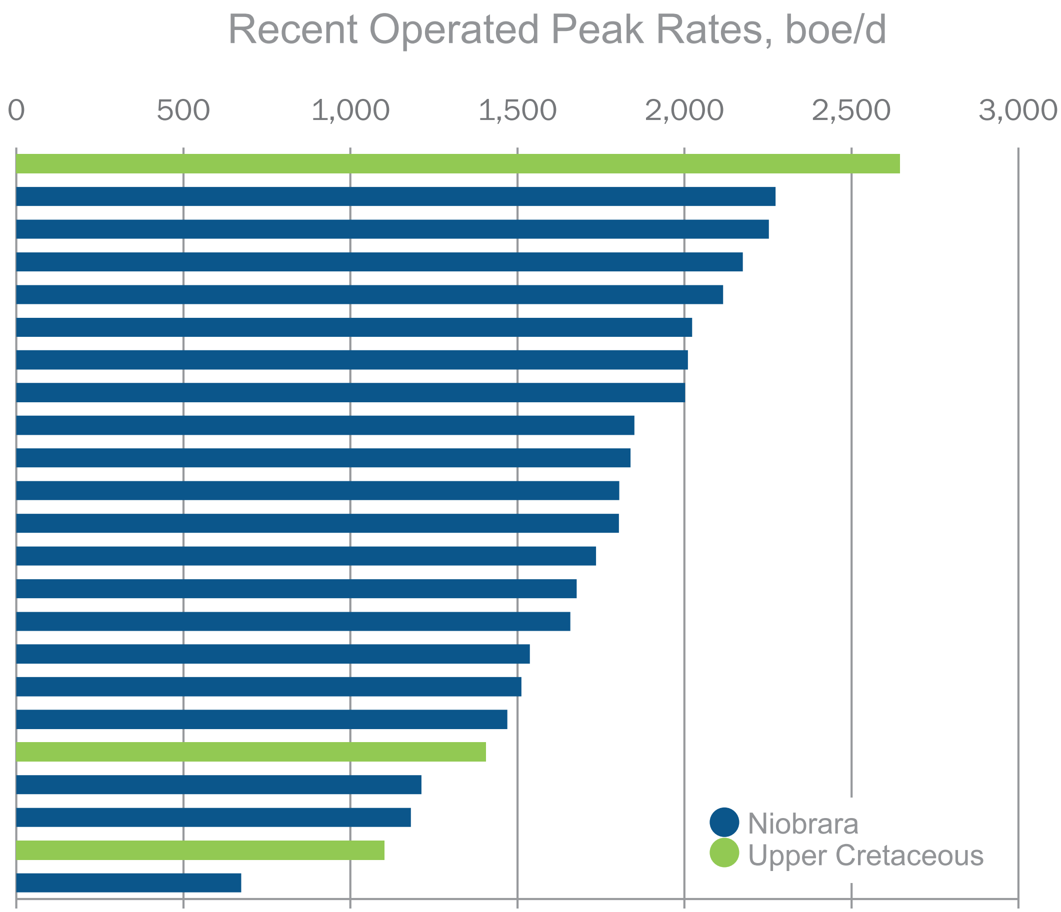
Operated locations(2)

Drilled	164
Producing	108
Inventory	54
Undrilled	1,800+

(1) 1Q'14 daily average net production
(2) Gross operated locations as of 3/31/2014; drilled locations include plugged and abandoned

Chesapeake ENERGY

POWDER RIVER BASIN
RECENT RESULTS

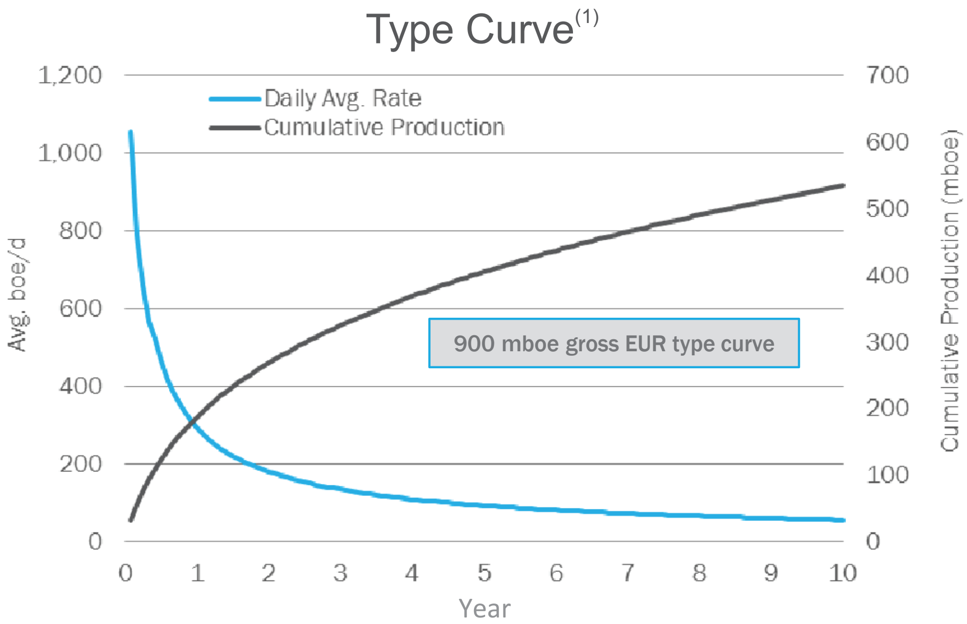


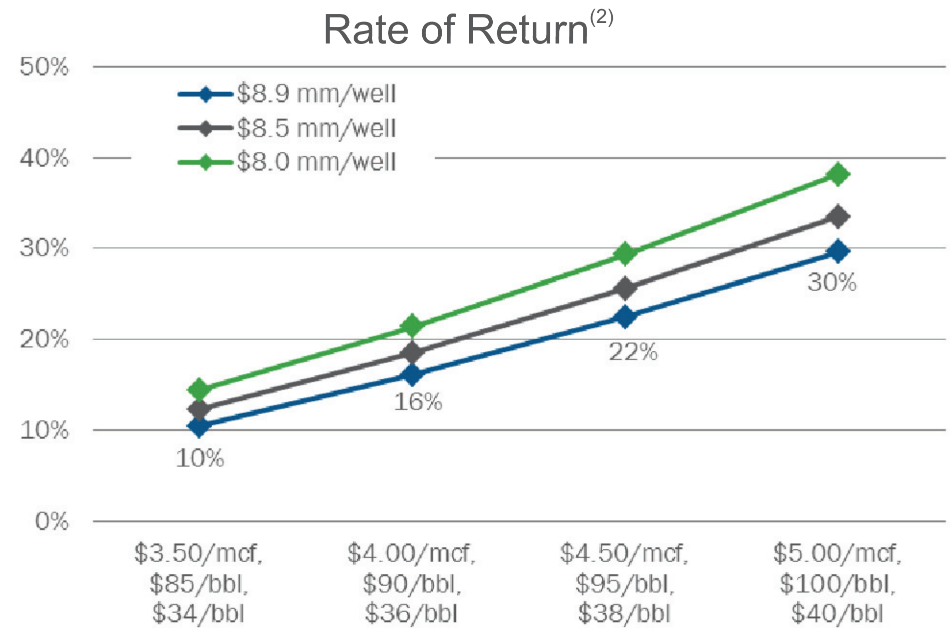
1,740 boe/d
Avg. recent Niobrara peak rate (50% oil)

2,025 boe/d
Avg. recent Sussex peak rate (60% oil)

1,105 boe/d
Recent Parkman peak rate (85% oil)

POWDER RIVER BASIN ECONOMICS





- First month avg: 1,056 boe/d
- Finding cost: $12.79/bbl
- Well cost: $8.9 mm
- ROR of 16% at $4/$90/$36[2]

40%
2014 expected program ROR net of carry[2]

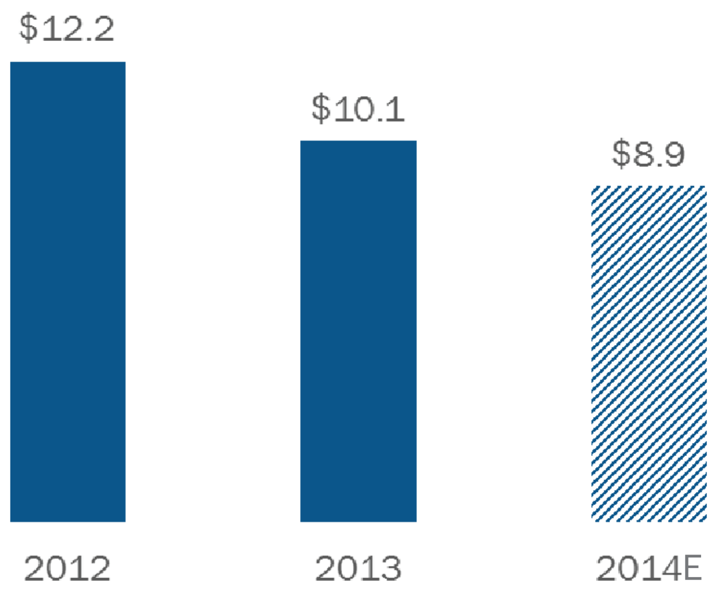
>30%
2015 Expected Program ROR[3]

(1) EUR assumes gas processing
(2) Assumes differentials to NYMEX prices of ($13.25)/bbl oil and ($2.73)/mcf natural gas for gathering/transportation costs and regional basis differentials. Also assumes 145 day avg. spud to TIL cycle time delay
(3) Increase in program ROR due to a combination of well mix, type curve and well cost
Note: type curve and rates of return represent 2014 program

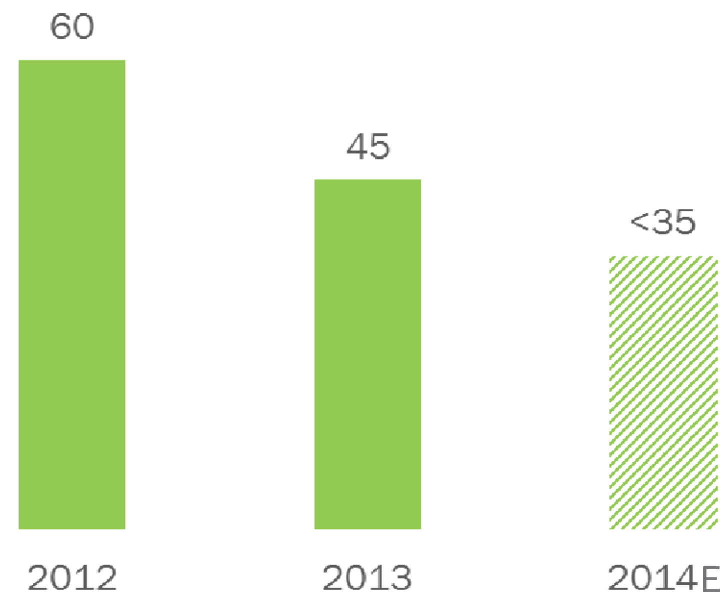
Chesapeake ENERGY

POWDER RIVER BASIN
CONTINUOUS IMPROVEMENT

Avg. Niobrara Well Cost ($ in mm)



Spud to Spud Cycle Times (days)



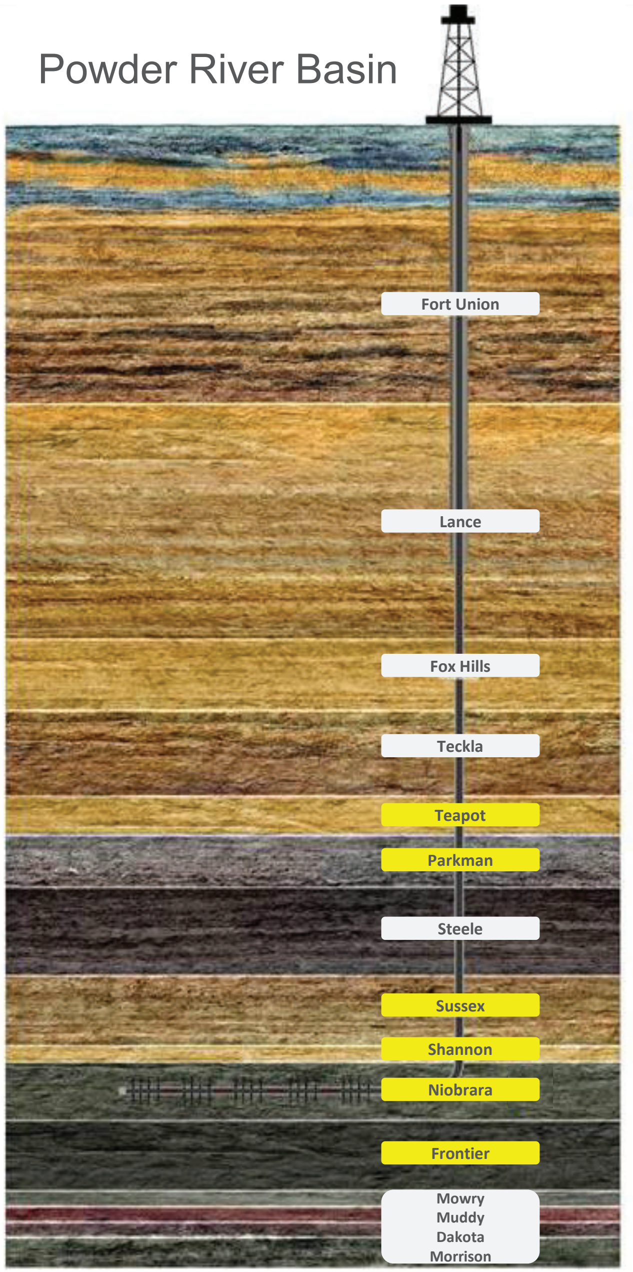
- Focused on continuous improvement in 2014
  - > Avg. lateral length of 5,800 ft. and 17 stages
  - > Testing longer laterals
  - > Optimizing completion design

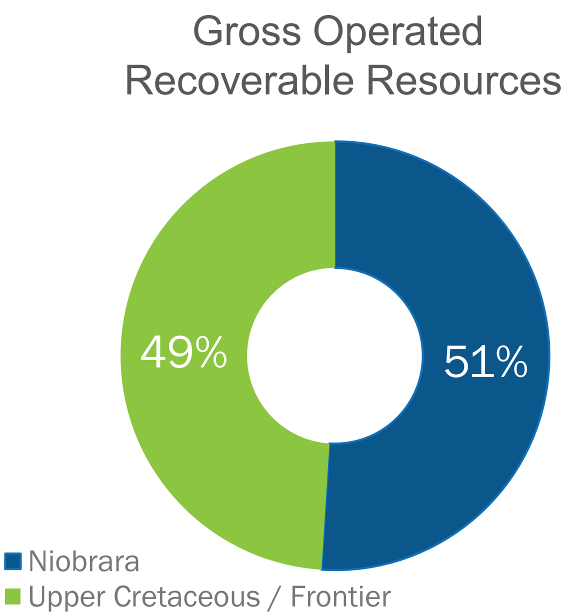
$7.6 mm
Record D&C well cost

23 days
Record spud to rig release

Chesapeake ENERGY

POWDER RIVER BASIN
THE PRIZE





>1.3 billion boe

Gross recoverable resources
(12% recovery factor)

>50% oil

Significant liquids contribution leading to higher margins and profitability

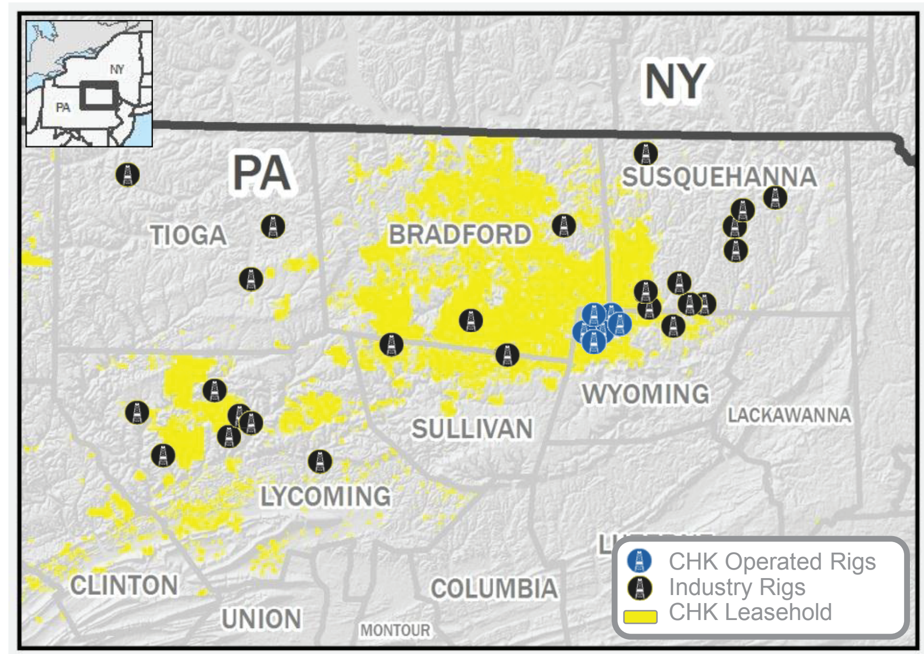
Chesapeake ENERGY

MARCELLUS
OPTIMIZING A WORLD-CLASS ASSET

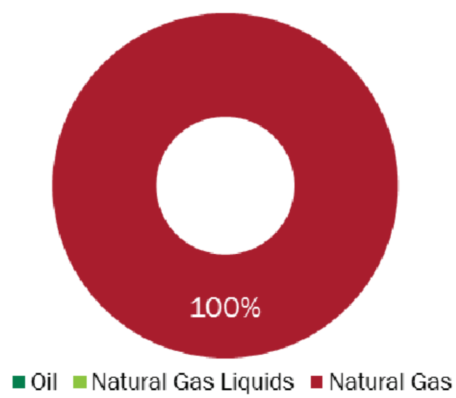
Chesapeake ENERGY

NORTHERN MARCELLUS ASSET OVERVIEW

- ~9 tcfe of net recoverable resources
- 230,000+ net acres[1]
  - > 39% avg. WI, 34% avg. NRI
- Net production of ~910 mmcfe/d[2]
- 5 - 7 operated rigs in 2014



Production mix[2]



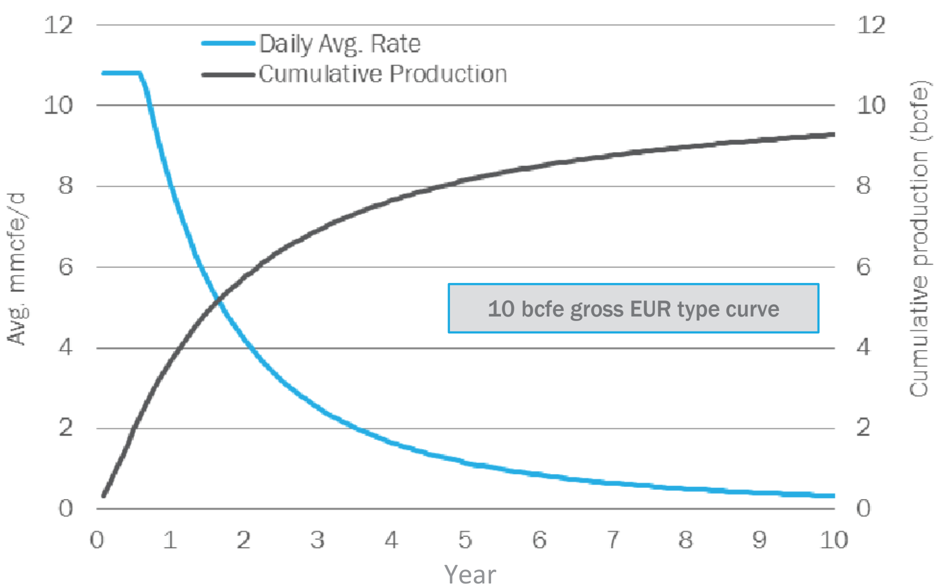
Operated locations[3]

Drilled	753
Producing	610
Inventory	110
Undrilled	2,000+

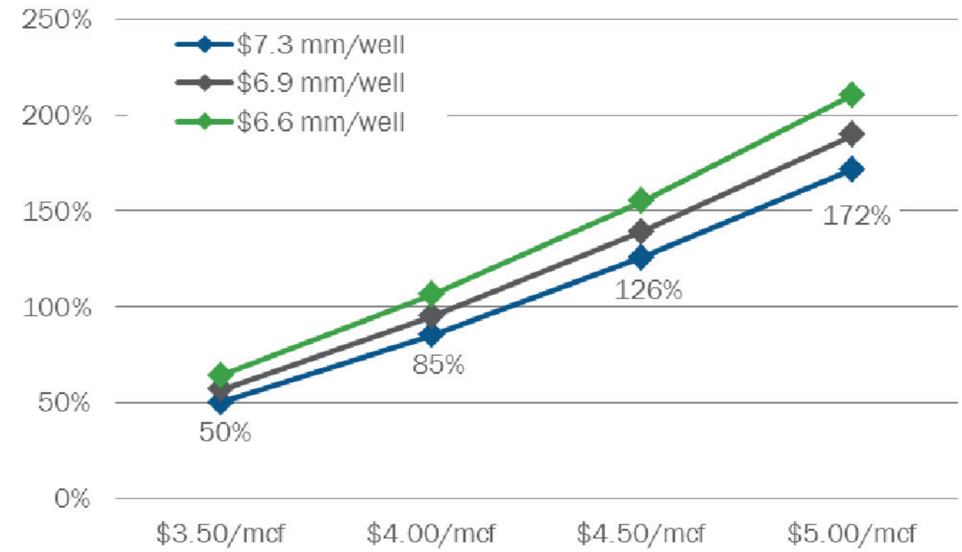
(1) Excludes acreage off main development fairway
(2) 1Q'14 daily average net production
(3) Gross operated locations as of 3/31/2014; drilled locations include plugged and abandoned; excludes Upper Marcellus Shale potential

NORTHERN MARCELLUS ECONOMICS

Type Curve



Rate of Return(1)



- First month avg: 10.8 mmcfe/d
- Finding cost: $0.85/mcf
- Well cost: $7.3 mm
- ROR of 85% at $4/mcf(1)

~50%

Decrease in spud to TIL cycle time from 2013 to 2014E

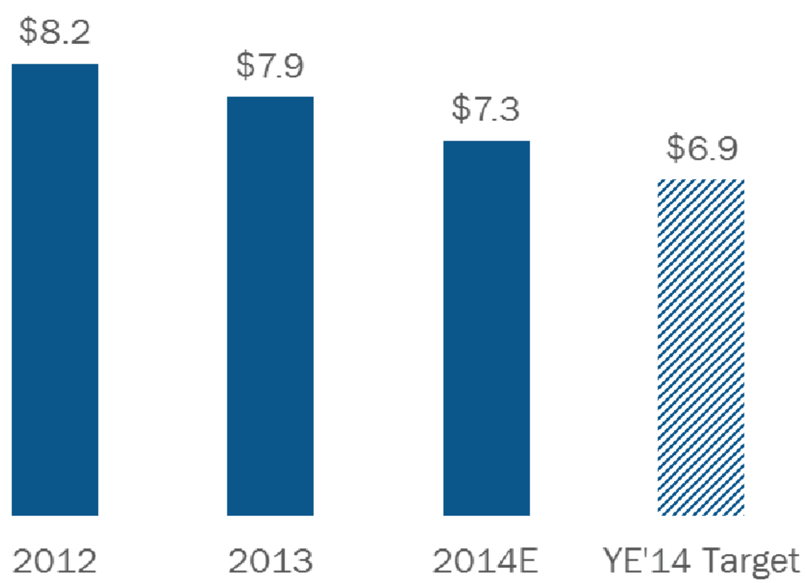
~25%

Increase in ROR attributed to TIL cycle time improvement

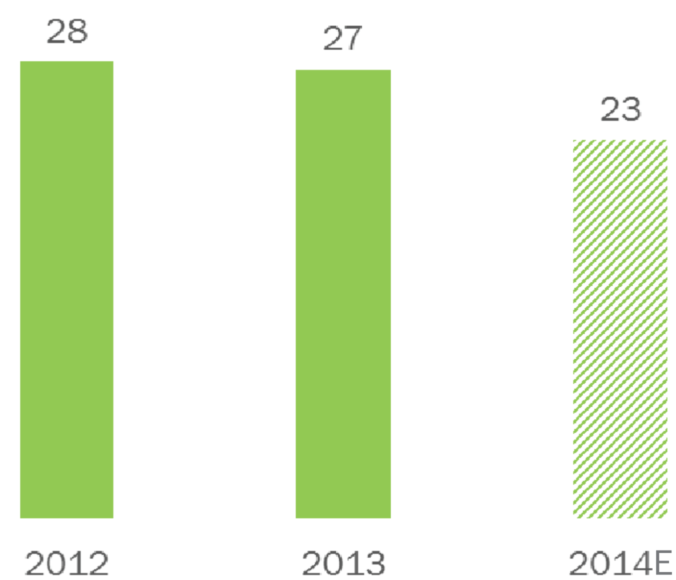
(1) Assumes differentials to NYMEX natural gas prices of ($1.35)/mcf for gathering/transportation costs and regional basis differentials. Also assumes 120 day avg. spud to TIL cycle time delay
Note: type curve and rates of return represent 2014 program

NORTHERN MARCELLUS CONTINUOUS IMPROVEMENT

Avg. Well Cost ($ in mm)



Spud to Spud Cycle Times (days)



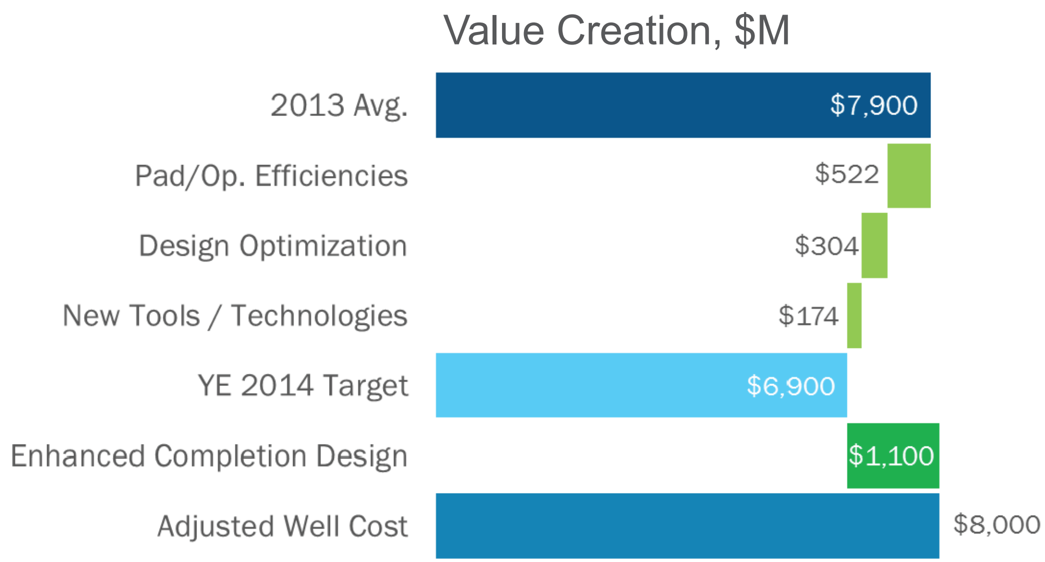
- Focused on continuous improvement in 2014
  - > YTD well costs already below 2014 estimated avg.
  - > Avg. lateral lengths of 6,000 ft. and 20 - 25 stages
  - > Minimizing downtime and base decline

>95%
2014E multi-well pad drilling utilization

<5%
1Q'14 average downtime with 40 inches of snow

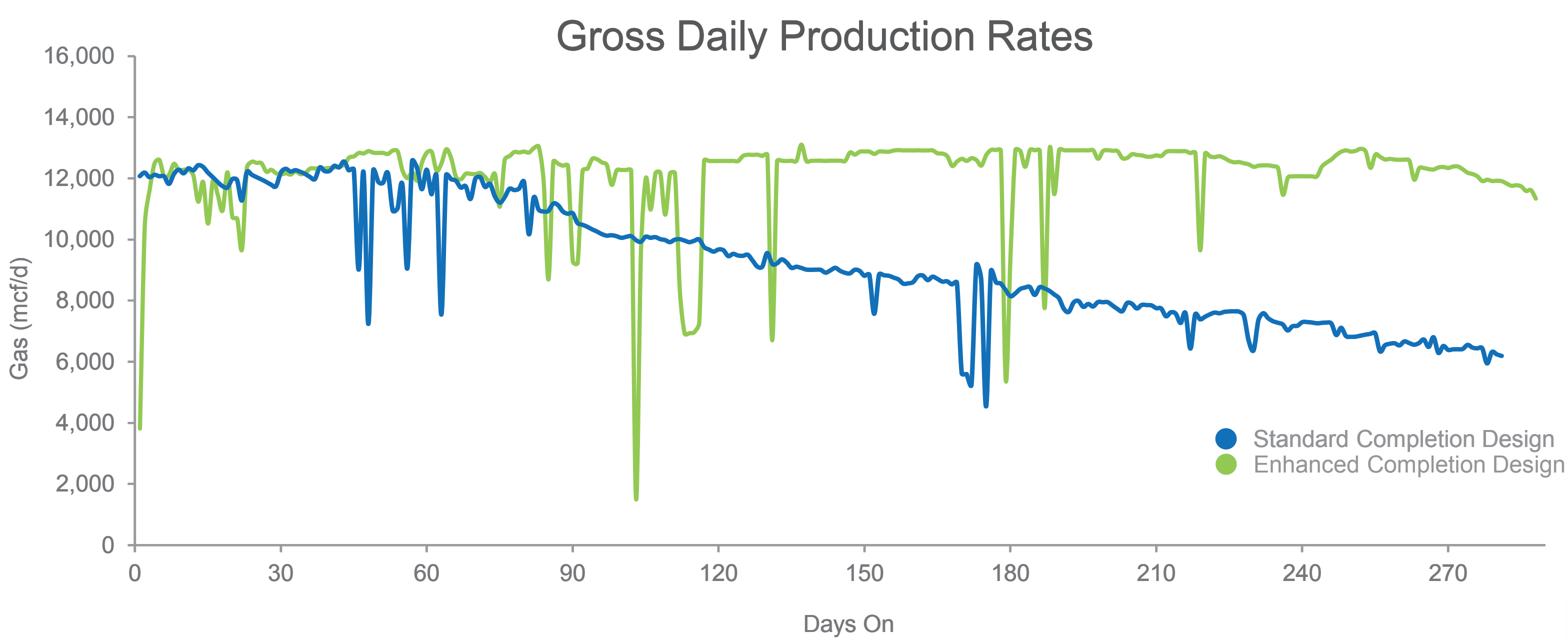
Chesapeake ENERGY

NORTHERN MARCELLUS DRIVING VALUE



$1 million
2014 savings reinvested into completions optimization

55%
ROR on reinvested capital



Chesapeake ENERGY

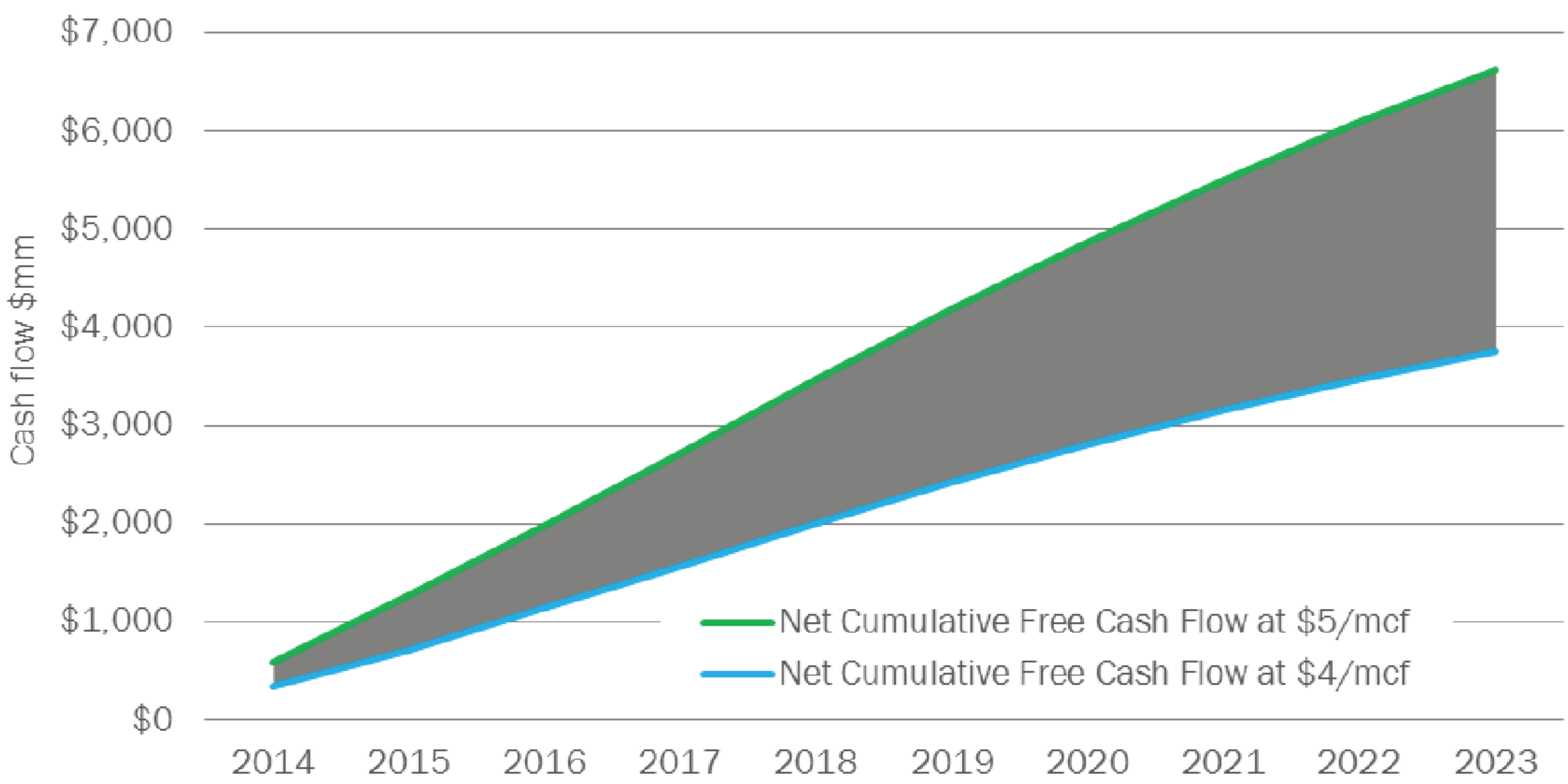
NORTHERN MARCELLUS
IMPACT OF HOLDING PRODUCTION FLAT

$300 mm - 5 Rigs

Net capital required per year to hold gross production flat at 2.2 bcf/d

$4 - $7 billion

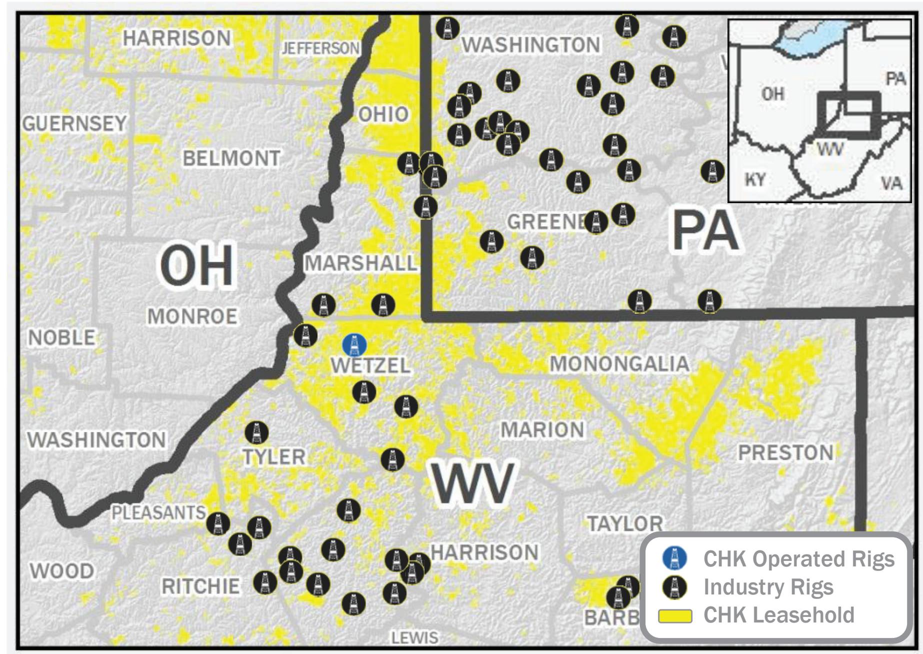
Cumulative Net FCF over the next 10 years



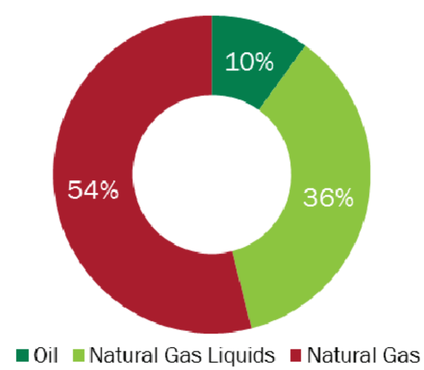
Assumes $4.00 and $5.00 NYMEX pricing and is fully burdened with differentials and cycle time

SOUTHERN MARCELLUS ASSET OVERVIEW

- ~2.7 bboe of net recoverable resources
- 250,000+ net acres
  - 68% avg. WI, 57% avg. NRI
- Net production of 55 mboe/d[1]
- 1 - 2 operated rigs in 2014



Production mix[1]

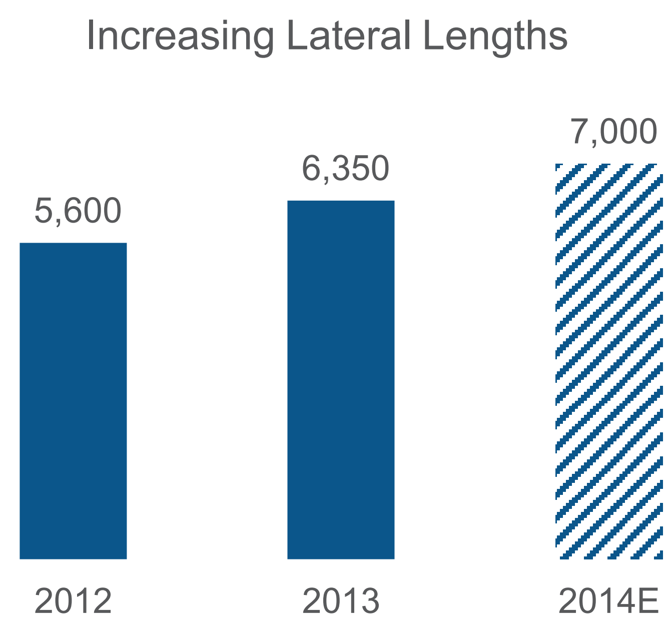


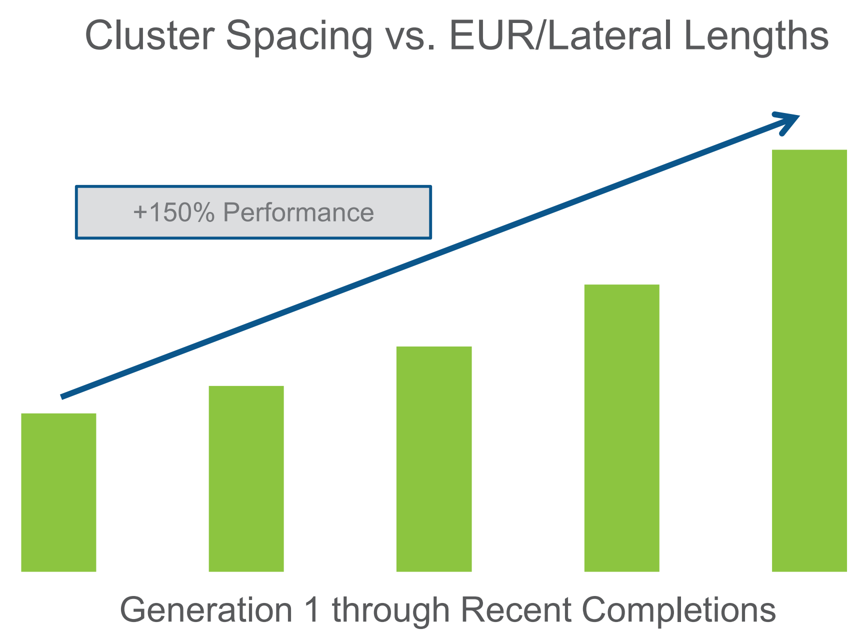
Operated locations[2]

Drilled	313
Producing	255
Inventory	52
Undrilled	1,200+

(1) 1Q'14 daily average net production
(2) Gross operated locations as of 3/31/2014; drilled locations include wells plugged and abandoned

SOUTHERN MARCELLUS CONTINUOUS IMPROVEMENT





- Focused on continuous improvement in 2014
  - > Drilling longer laterals
  - > Optimizing completions
  - > Driving down cycle times

7 - 20 bcfe/well
Range of EURs across S. Marcellus

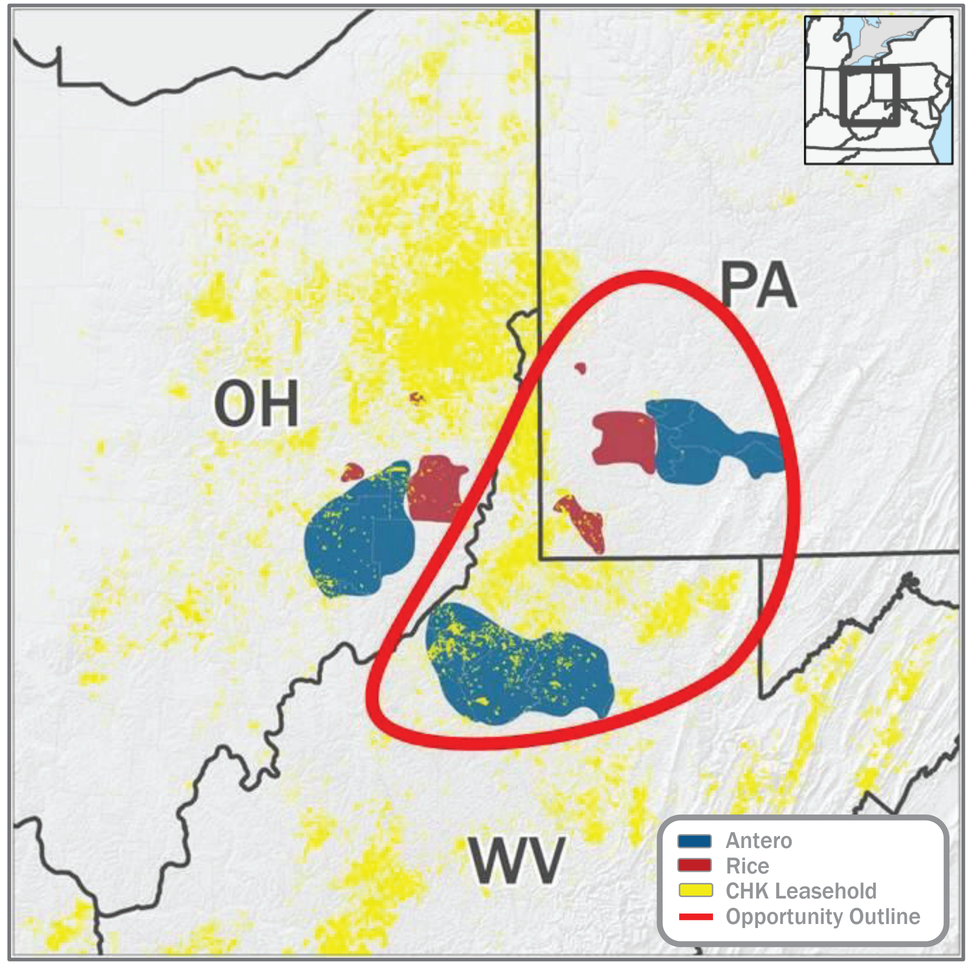
+35%
Increase in EUR from recent completions test

SOUTHERN MARCELLUS VALUE AND GROWTH OPPORTUNITY

- Potential to unlock significant value
  - Combination of dry gas Utica and liquids-rich S. Marcellus acreage
  - Annual organic growth potential >50%
  - Ramp activity into expanding capacity

250,000+
Net Southern Marcellus acres not including 165,000+ net acres of stacked Utica potential

$4 - $8 billion(1)
Valuation implied by market multiples



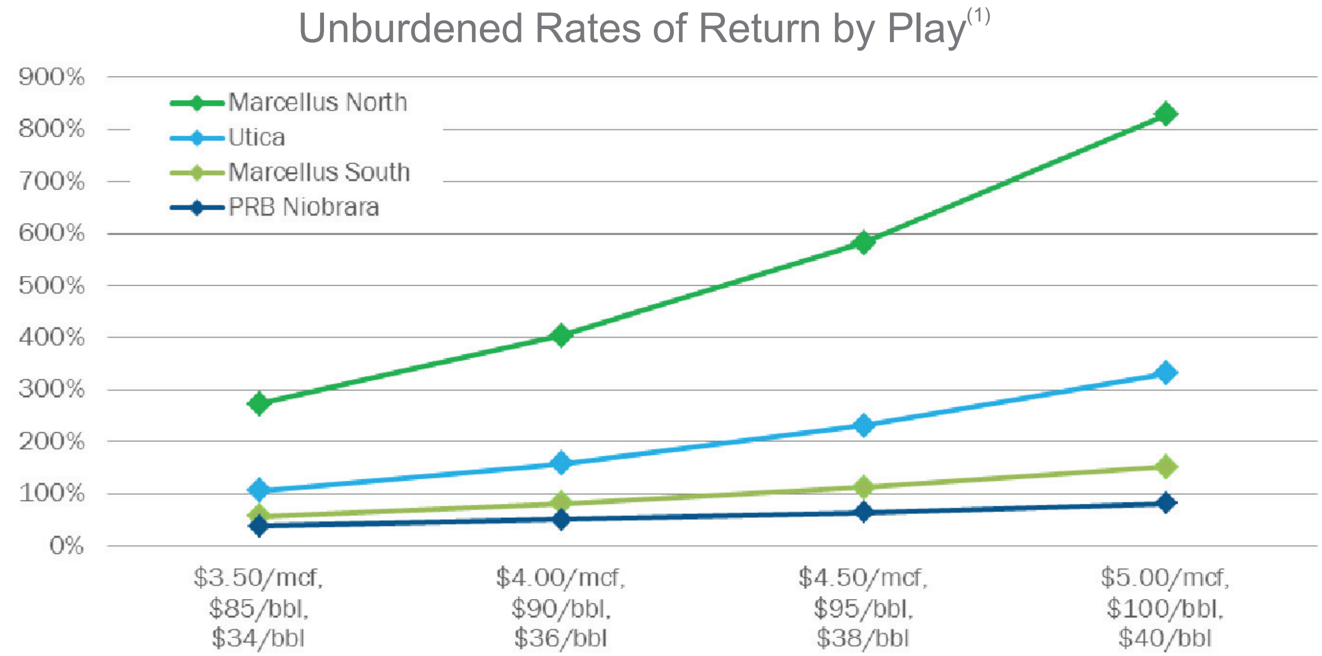
Antero and Rice leasehold positions sourced from public information

(1) Based on Antero's market data as of 5/12/2014. Leasehold, production and locations sourced from public information

NORTHERN DIVISION

APPENDIX

NORTHERN DIVISION UNBURDENED ECONOMICS

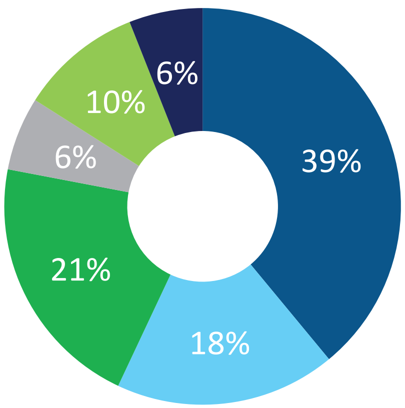


	Marcellus North	Utica	Marcellus South	PRB Niobrara
2014E Well Cost ($ in mm)	$7.3	$7.4	$9.2	$8.9
$3.50/mcf; $85/bbl oil; $34/bbl NGL	273%	105%	56%	38%
$4.00/mcf; $90/bbl oil; $36/bbl NGL	404%	158%	81%	50%
$4.50/mcf; $95/bbl oil; $38/bbl NGL	583%	230%	112%	64%
$5.00/mcf; $100/bbl oil; $40/bbl NGL	829%	331%	151%	81%

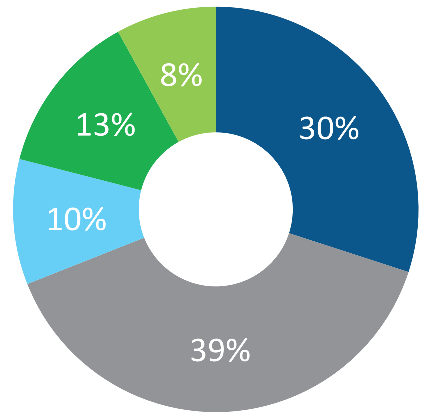
(1) Assumes NYMEX natural gas and oil prices, excludes spud to TIL cycle times

UTICA AND SOUTHERN MARCELLUS SALES POINTS

April - Oct ‘14 Sales Points



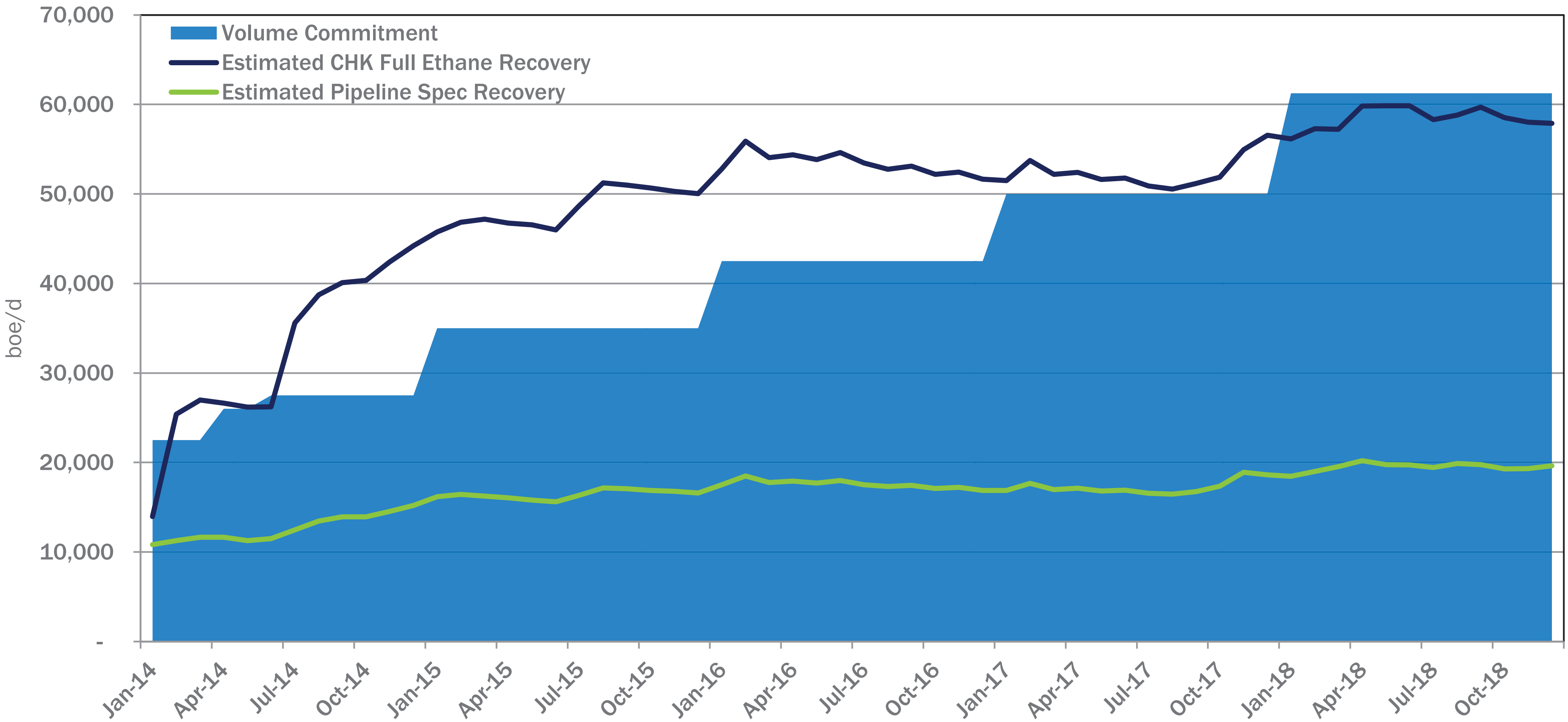
2015 Sales Points



	1Q’14A Diff. to HH	April - Oct ‘14 Basis Hedges	April - Oct ‘14 Hedged Volumes (mmcf/d)
TCO	($0.03)	($0.22)	105
Dominion South	($0.49)	($0.90)	45
WTD. Avg. Basis Hedged April - Oct ‘14		($0.42/mcf)	

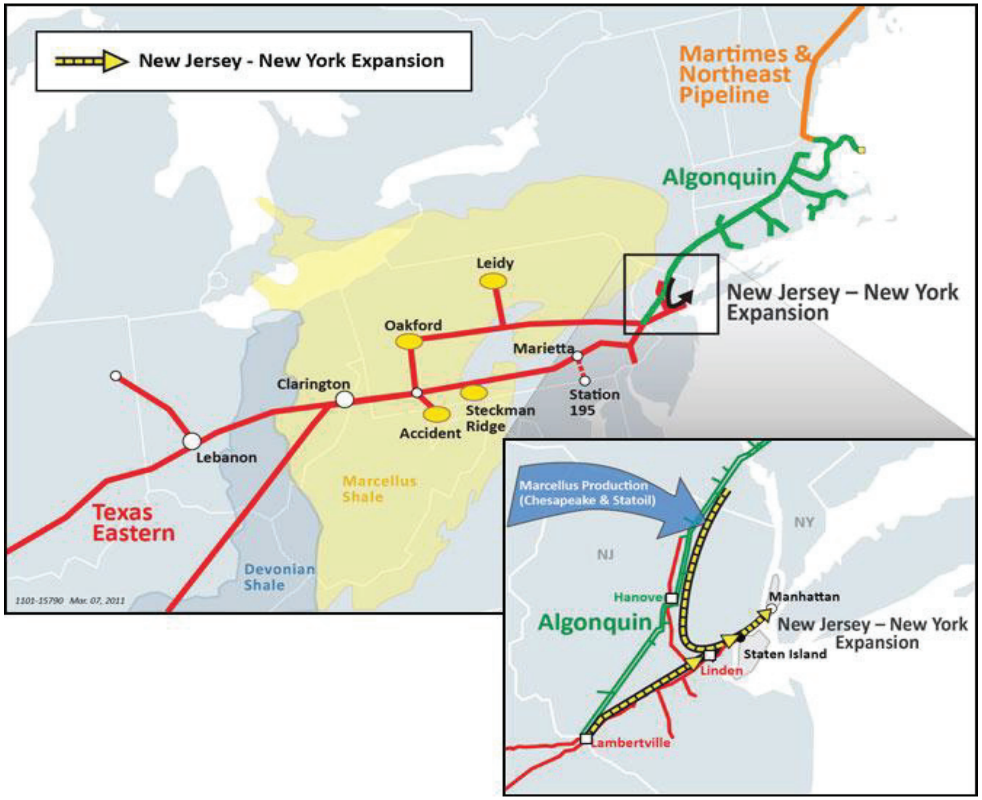
- ~31% of estimated April - October 2014 natural gas production will receive an average differential of ($0.42)/mcf
- ~40% and ~70% of 2014 estimated and 2015 estimated natural gas will receive Gulf Coast linked pricing, respectively

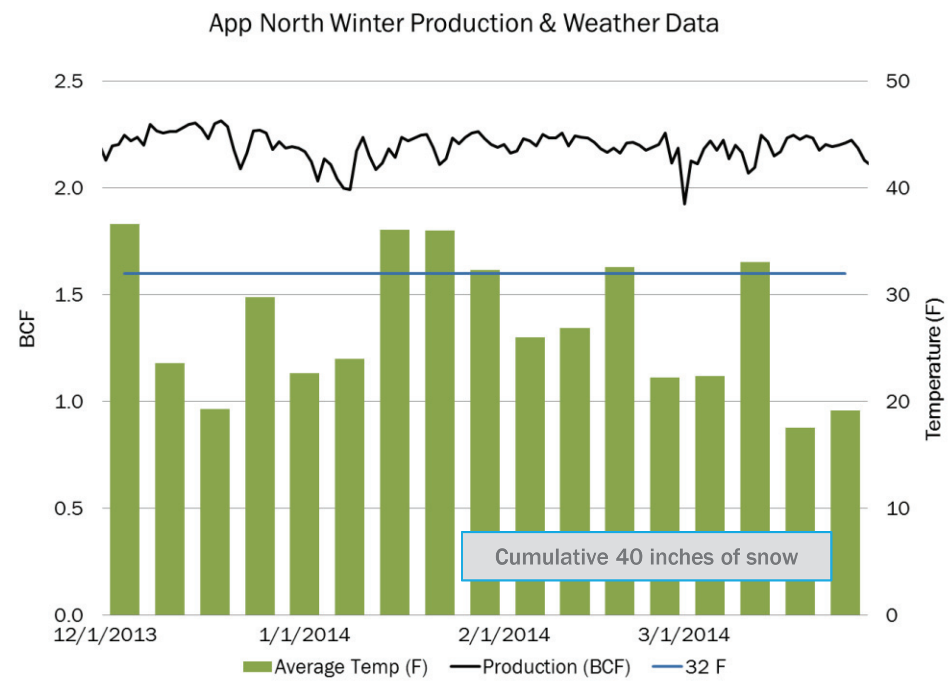
UTICA/SOUTHERN MARCELLUS ETHANE TAKEAWAY



CHK has the flexibility to optimize ethane recovery/rejection in order to maximize margins per boe

NORTHERN MARCELLUS
ASSET VALUE OPTIMIZATION





- Premium market development
- Optimization of trading positions
- High deliverability wells
- Best in class winter operations

Strength

Flexibility

Value Capture

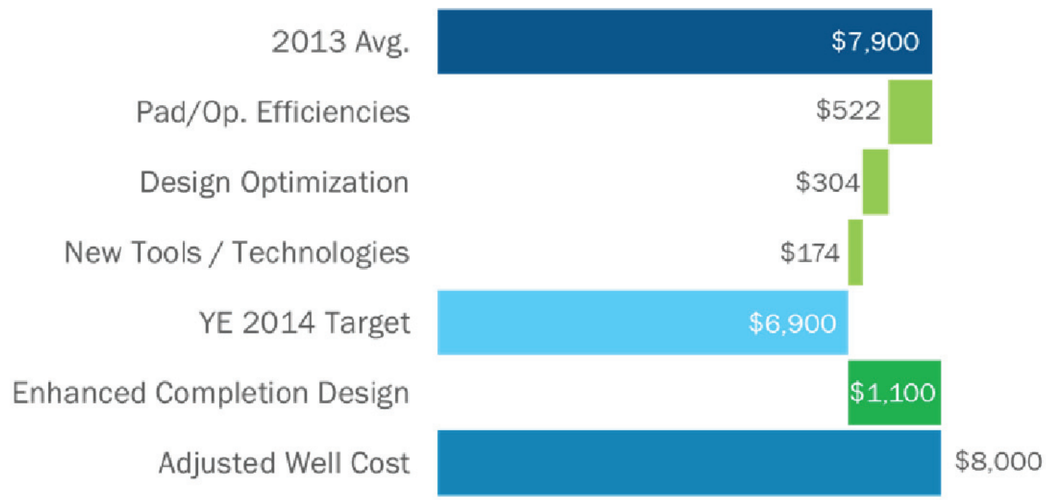
~$275 mm

Net Free Cash Flow in 1Q'14 with an avg. realized price of $4.86/mcf

Chesapeake ENERGY

NORTHERN MARCELLUS
CAPITAL EFFICIENCY AND VALUE CREATION

- Drilling optimization
  - > Complete curve section in one run
  - > Optimize well path with rate of penetration
  - > Utilization of OKC Operations Center
- Completion optimization
  - > Well specific stimulation designs tailored to reservoir rock quality, pressure, well spacing and subsurface complexity
  - > Utilize controlled testing, history matching and performance evaluation
- Completion design testing
  - > Decreasing cluster spacing
  - > Increasing proppant/foot
  - > Increase cluster efficiency

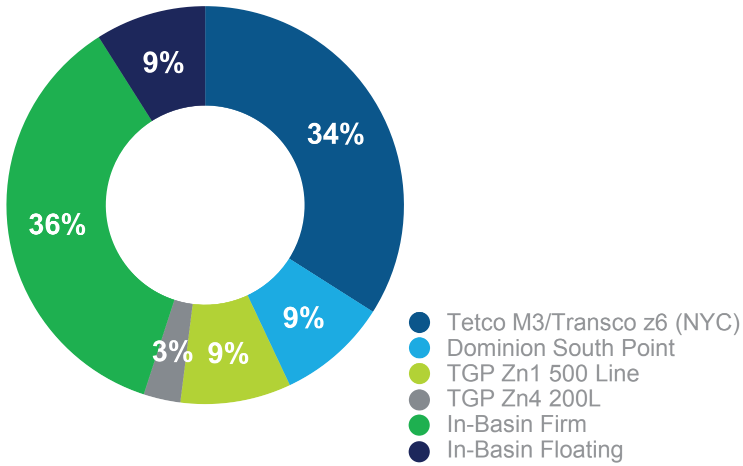


- Scheduling and logistic efficiencies
  - > Operational and cost efficiency with pad drilling
  - > Reduced cycle times with clustered pad completions
  - > Optimize deliverability to gas gathering systems by mitigating down production

Chesapeake ENERGY

NORTHERN MARCELLUS
NE PA FIRM TRANSPORT

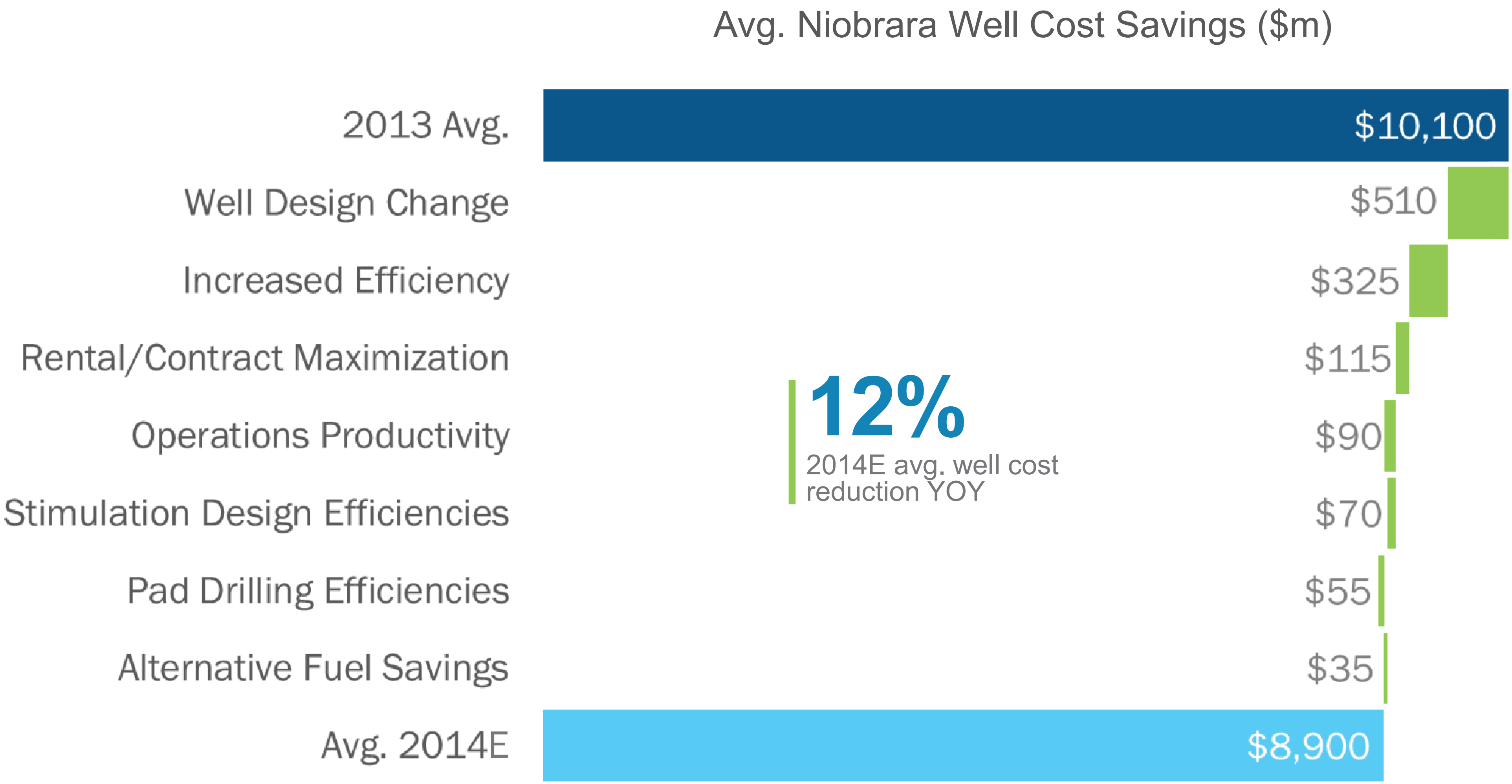
Estimated April - Oct '14 NE Sales Points



- ~38% of estimated Apr - Oct '14 gas will receive avg. basis differential of ($0.68)/mcf
- ~10% of estimated Apr - Oct '14 gas will receive Gulf Coast linked pricing
- ~35% of estimated Apr - Oct '14 gas sold in-basin under firm purchase agreements

Chesapeake ENERGY

POWDER RIVER BASIN
CAPITAL COST IMPROVEMENT

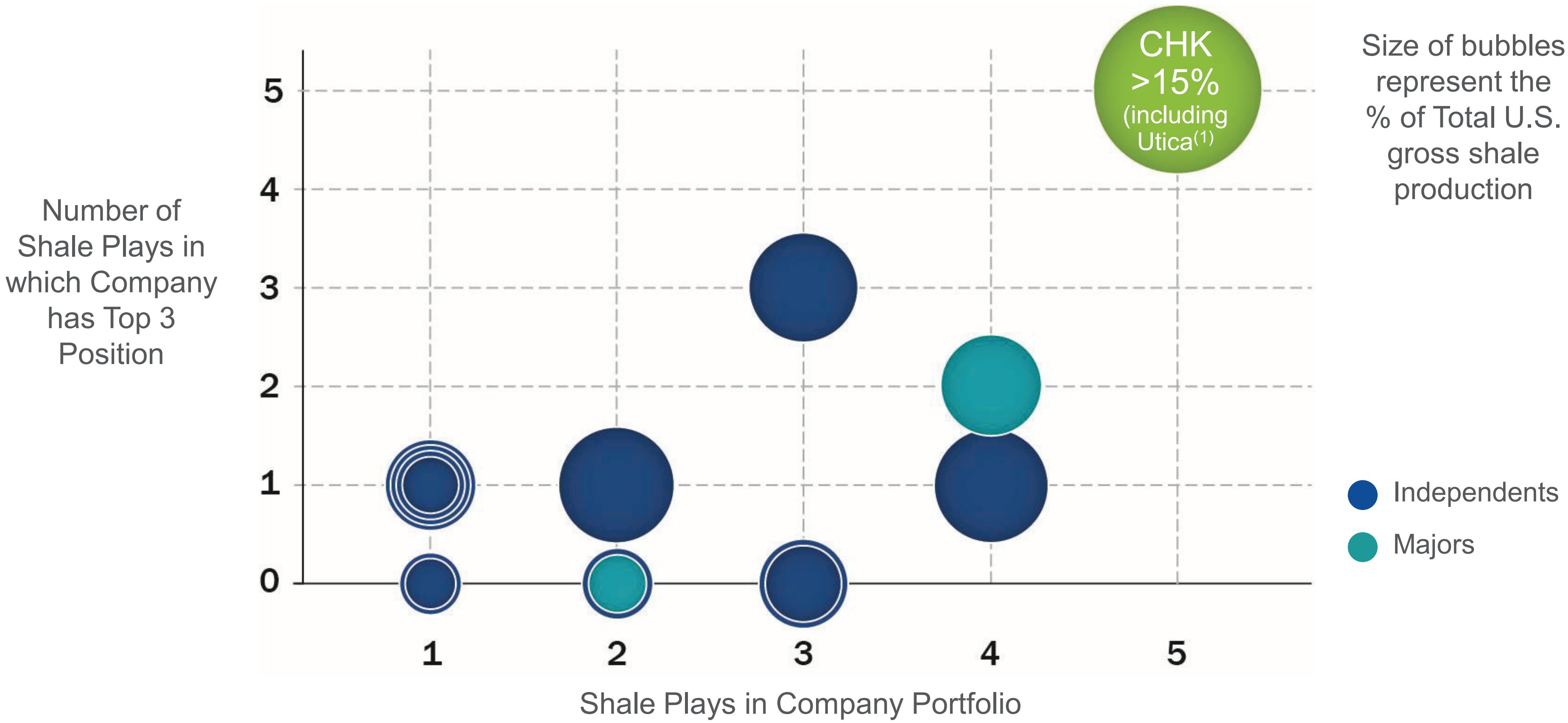


Chesapeake ENERGY

EXPLORATION & SUBSURFACE TECHNOLOGY

JOHN KAPCHINSKE
SVP - EXPLORATION & SUBSURFACE TECHNOLOGY

INDUSTRY LEADER IN U.S. SHALE PLAYS



- Geoscience technology driven growth
  > Differential technical capabilities
  > Growth from captured resources
  > Exploration growth opportunities

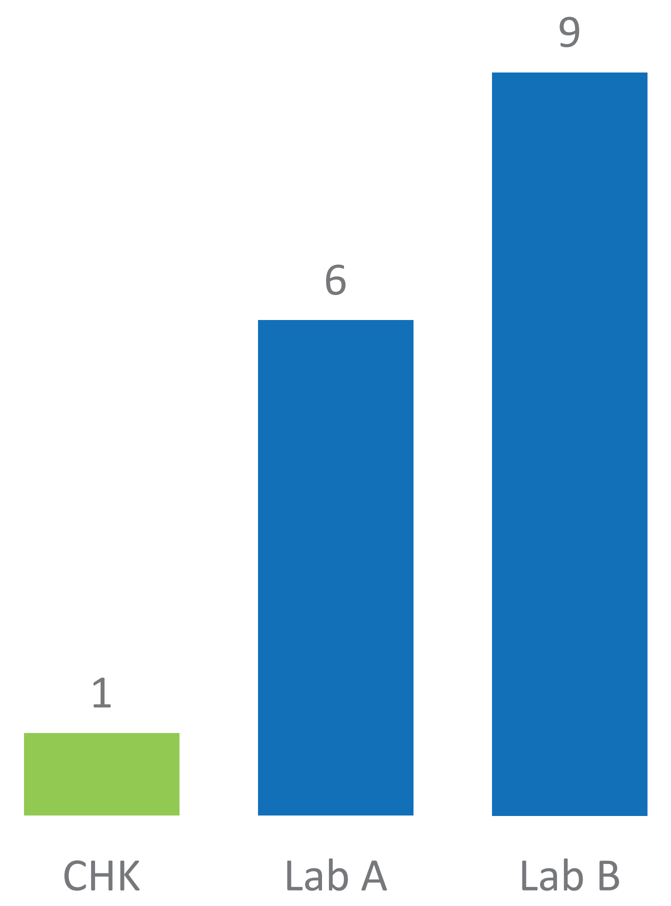
(1) Source: PFC Energy and CHK estimates (for Utica shale). Includes Barnett, Fayetteville, Haynesville, Marcellus, Eagle Ford, Bakken and Utica Shale plays.

DIFFERENTIAL TECHNICAL CAPABILITIES: RESERVOIR TECHNOLOGY CENTER

- CHK is the only independent E&P operator with a proprietary core lab
  - > Core analyses
  - > In-house research center
- Competitive advantages:
  - > Speed and accuracy
  - > Unique tight rock analysis

FINDING THE
NEXT BEST PLAY
DRILLING THE
NEXT BEST WELL

Time to Evaluate 500' of Core (Months)

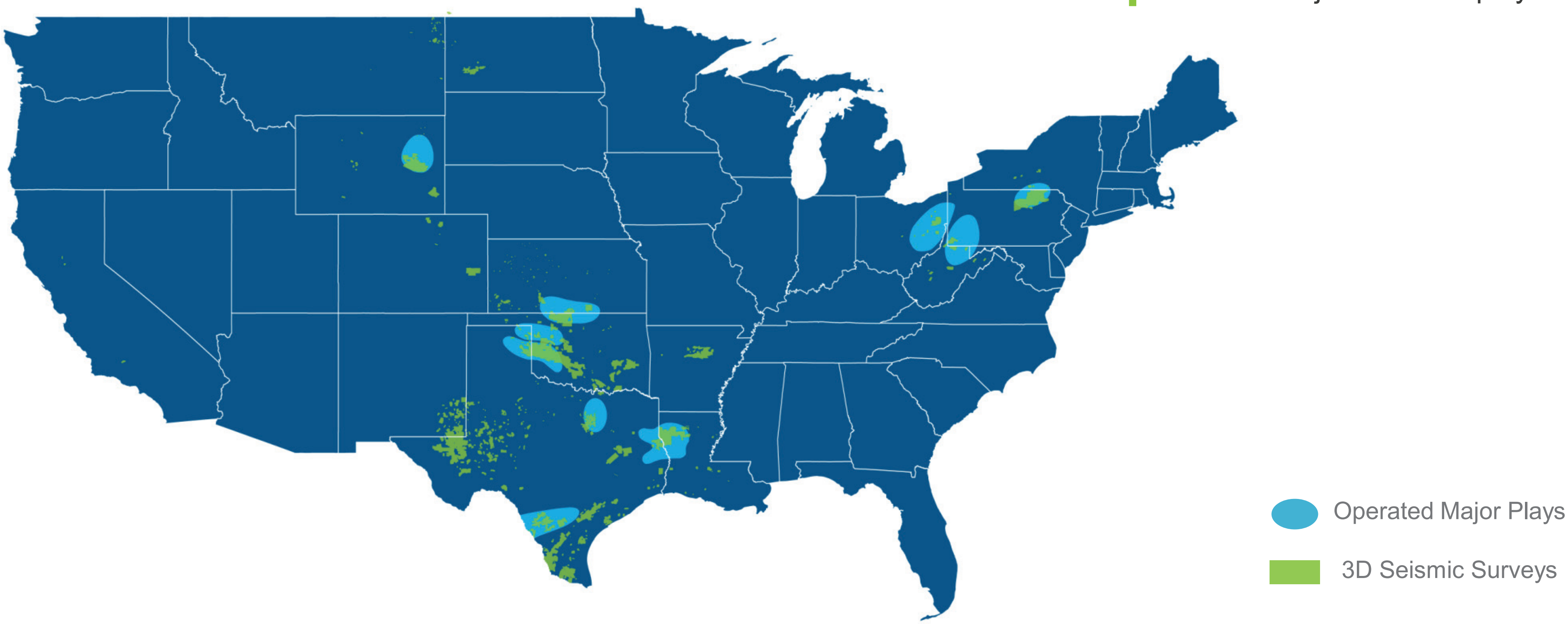


Chesapeake ENERGY

DIFFERENTIAL TECHNICAL CAPABILITIES: EXTENSIVE 3D SEISMIC COVERAGE

75 - 100%

3D seismic coverage over all CHK's major resource plays[(1)]

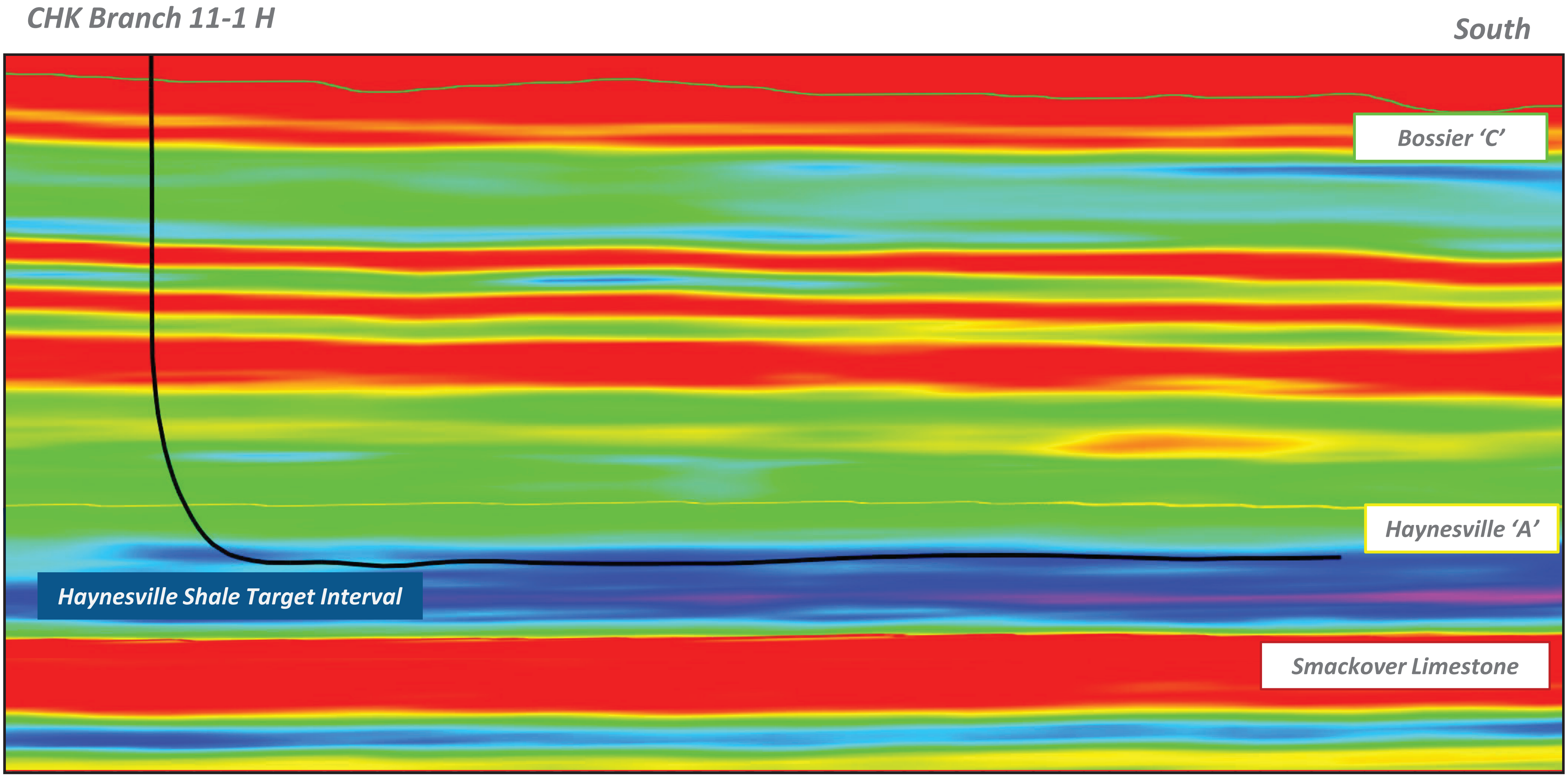


~33 million acres of 3D coverage over all major plays

(1) Excludes Utica Shale where additional 3D seismic shoot is planned in 2014 and 2015

Chesapeake ENERGY

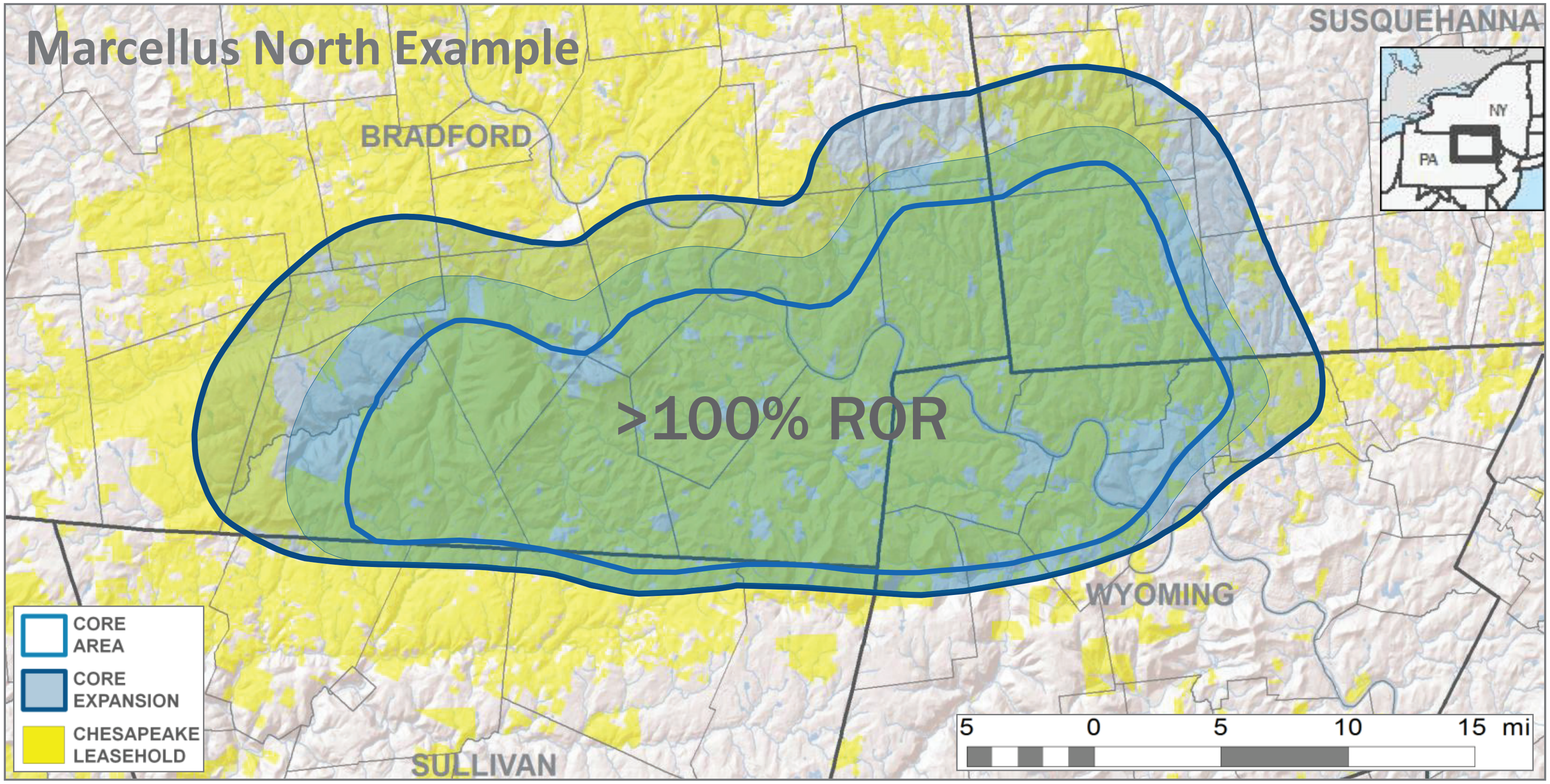
DIFFERENTIAL TECHNICAL CAPABILITIES: SEISMIC INVERSION – BRITTLENESS



- 3D seismic data was originally used to steer lateral wellbores along structure
- Seismic inversion is a statistical method to distribute rock properties between sparse petrophysical and core control
- Evaluate reservoir intervals, not boundaries

Chesapeake ENERGY

GROWTH FROM CAPTURED RESOURCES: EXPAND THE CORE

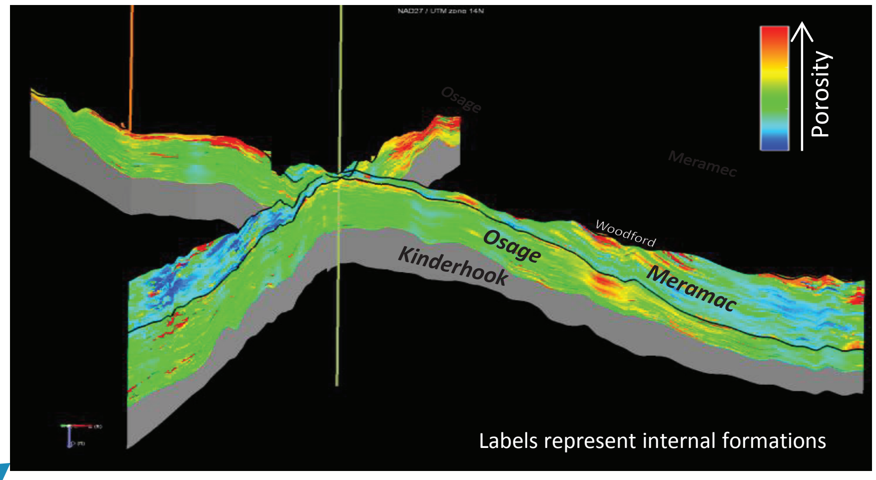


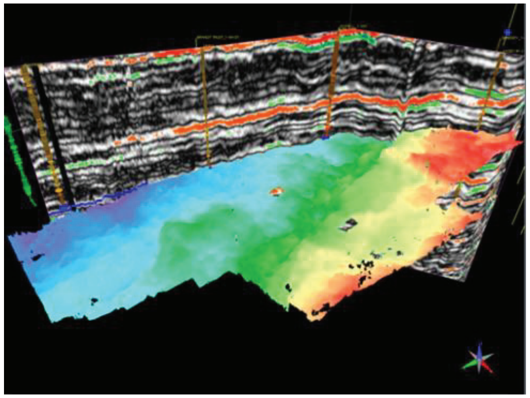
- Capital Efficiency
  > Pad Drilling
  > Peake Drilling
  > 24/7 Ops Center
  > Supply Chain
- Improved EUR's
  > Reservoir Characterization
  > Targeting
  > Steering
  > Optimize Completions

Chesapeake ENERGY

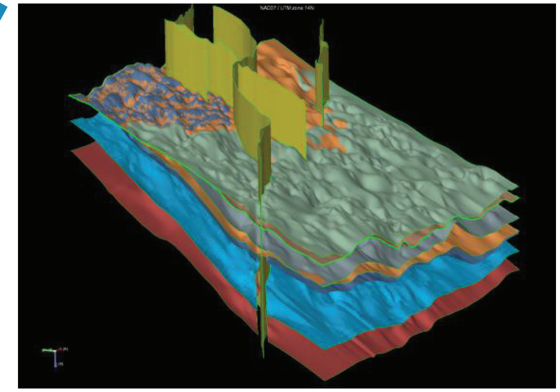
GROWTH FROM CAPTURED RESOURCES: OPTIMIZING MISS LIME

Miss-Lime 3D Earth Model

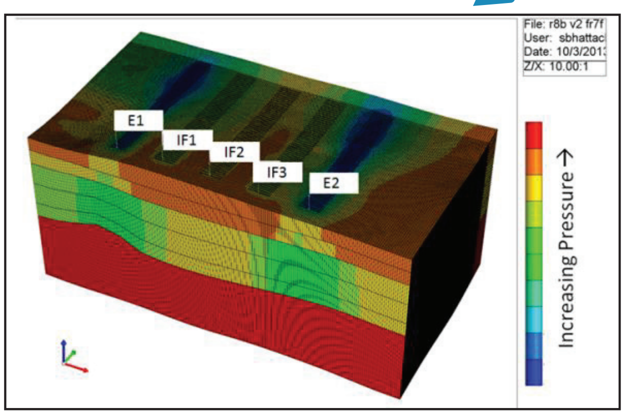




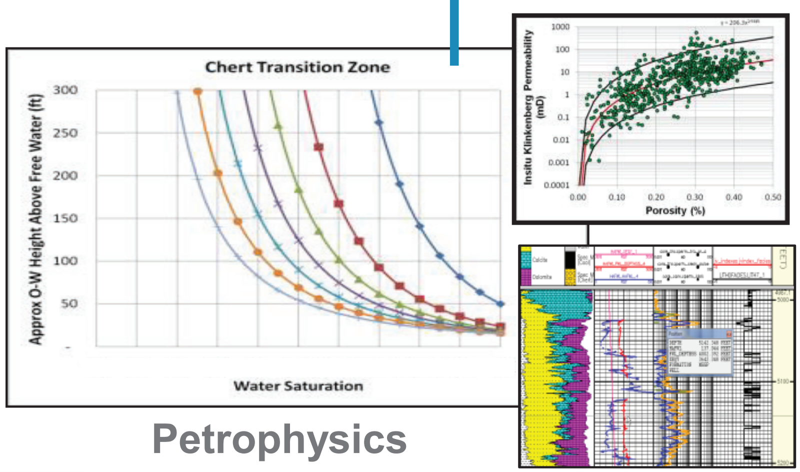
Geophysics



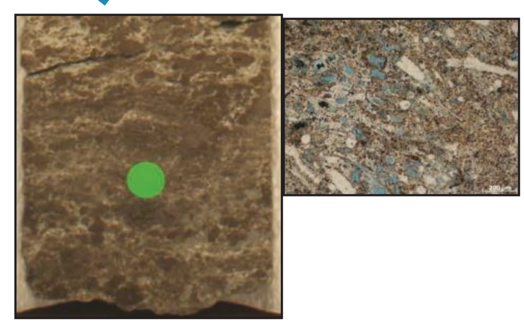
Geology



Reservoir Engineering

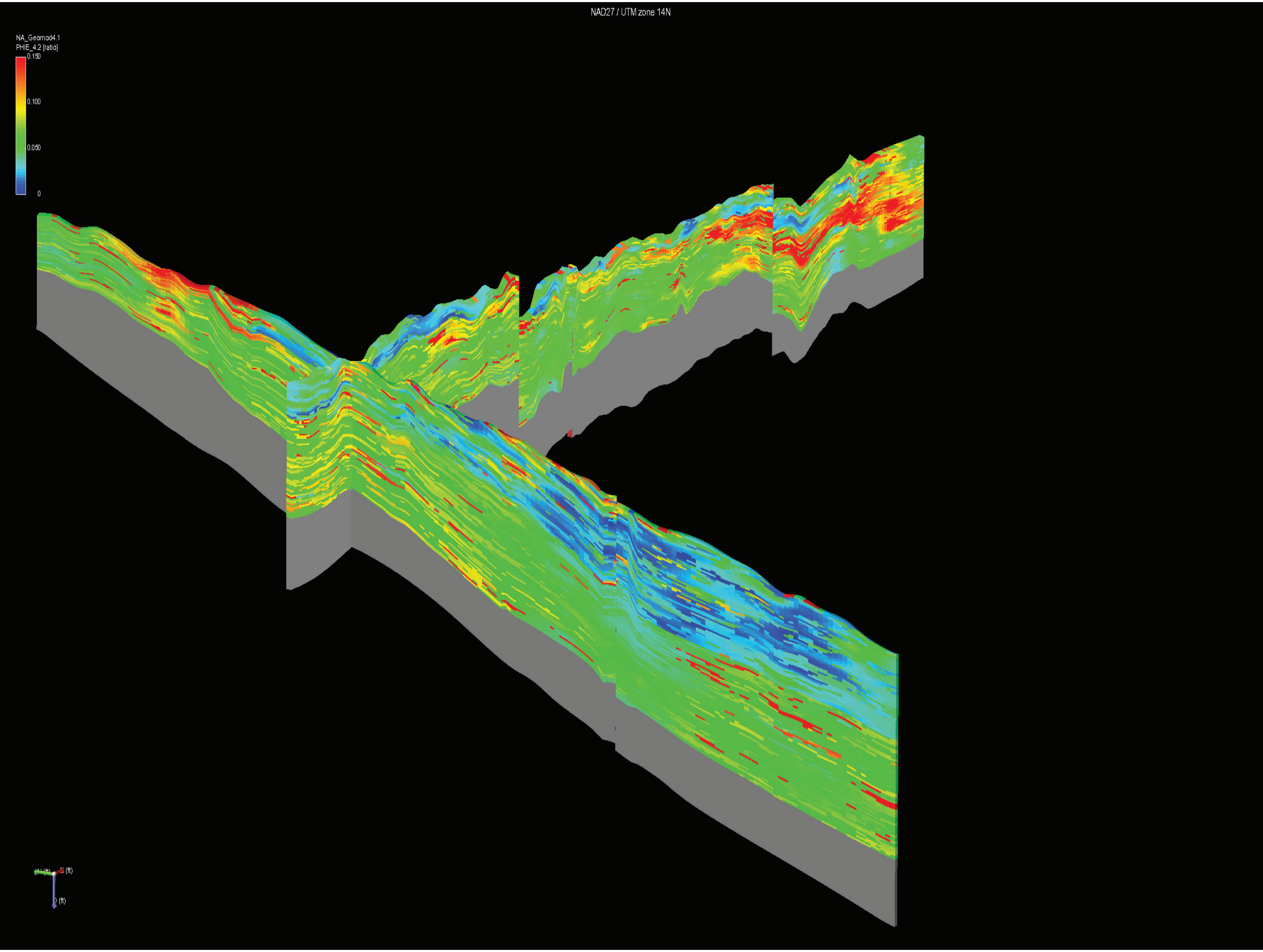


Petrophysics

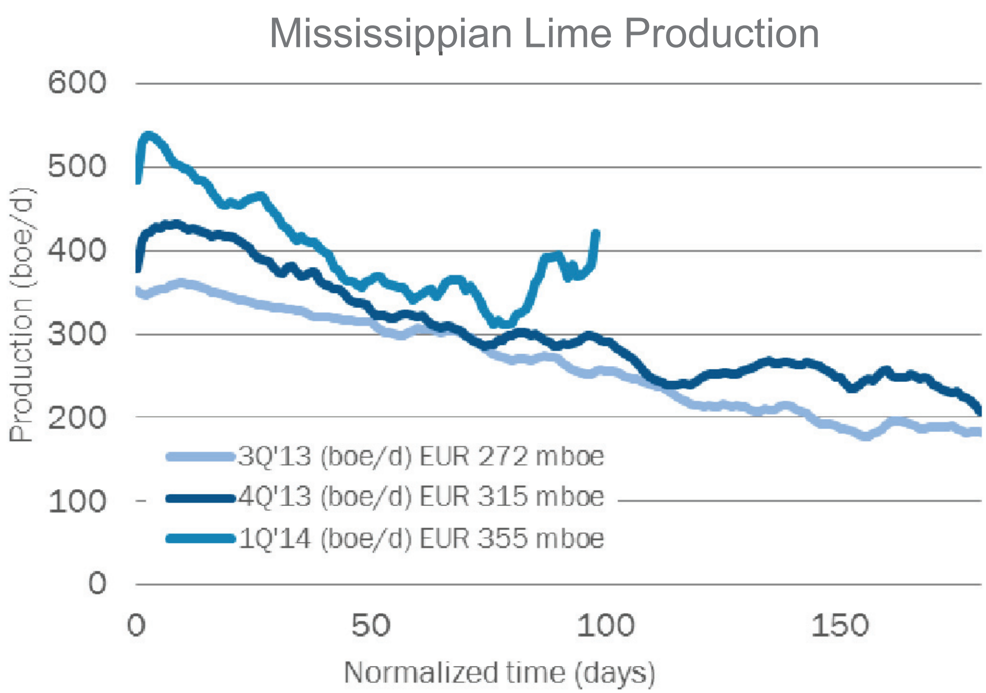


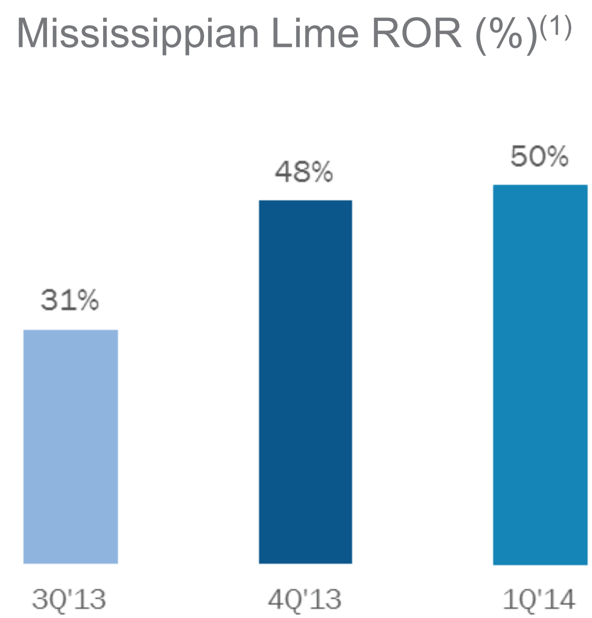
RTC

Chesapeake ENERGY


NAD27 / UTM zone 14N
NA_Geomod4.1
PHIE_4.2 [ratio]
0.150
0.100
0.050
0

MID-CONTINENT
MISSISSIPPIAN LIME PRODUCTION IMPROVES





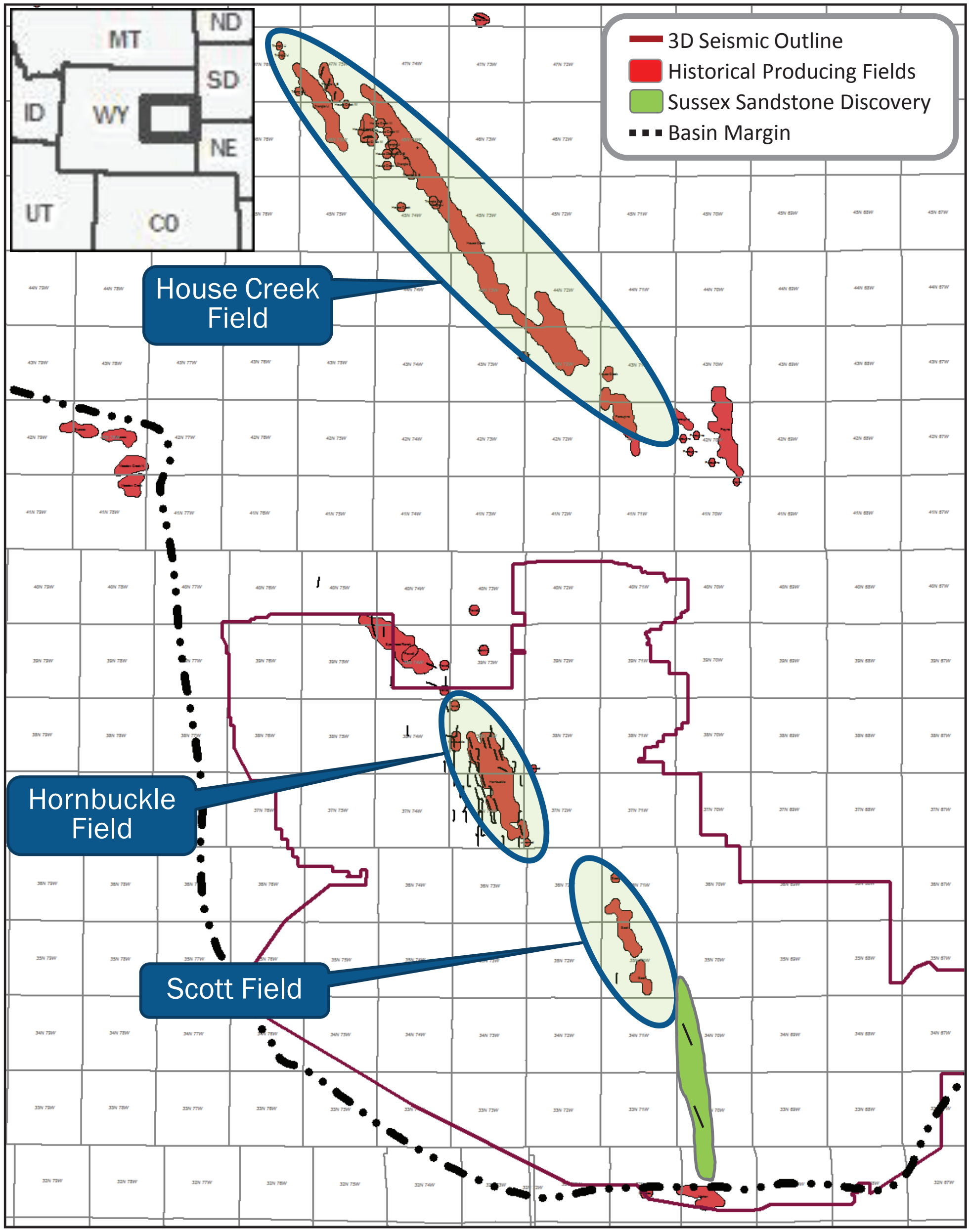
- Integrated teams are increasing project returns
- Improved EURs and performance from historical trends are a result of
  - > Reservoir characterization
  - > Targeting
  - > Steering
  - > Completion optimization

31%
Increased EUR performance from 3Q'13 to 1Q'14

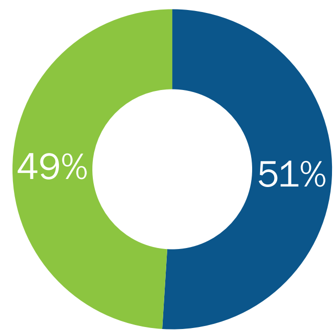
(1) Based on a $4.00/$90/$36 price assumption

Chesapeake ENERGY

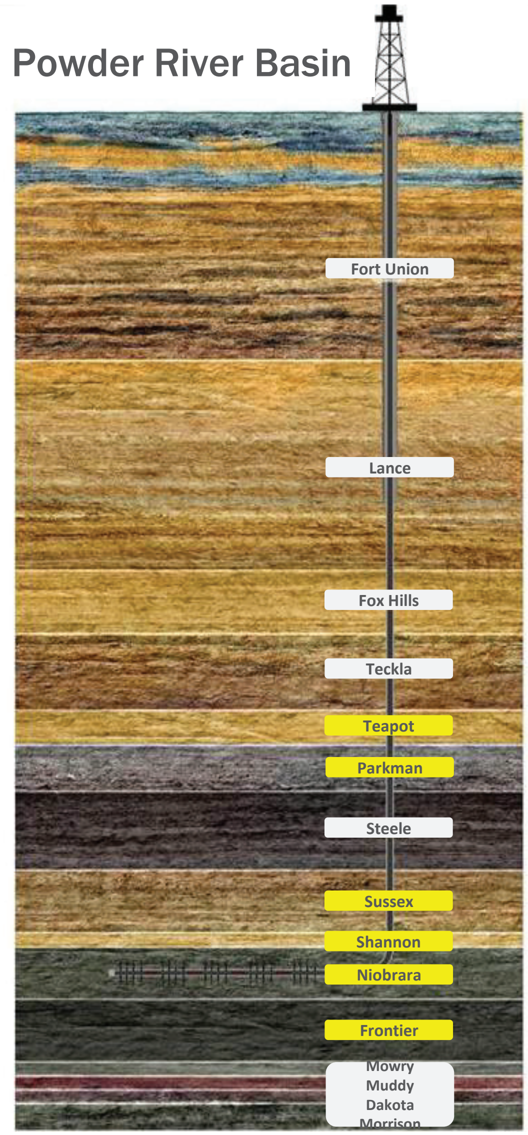
EXPLORATION GROWTH OPPORTUNITIES: SUSSEX SANDSTONE



Gross Operated Recoverable Resource



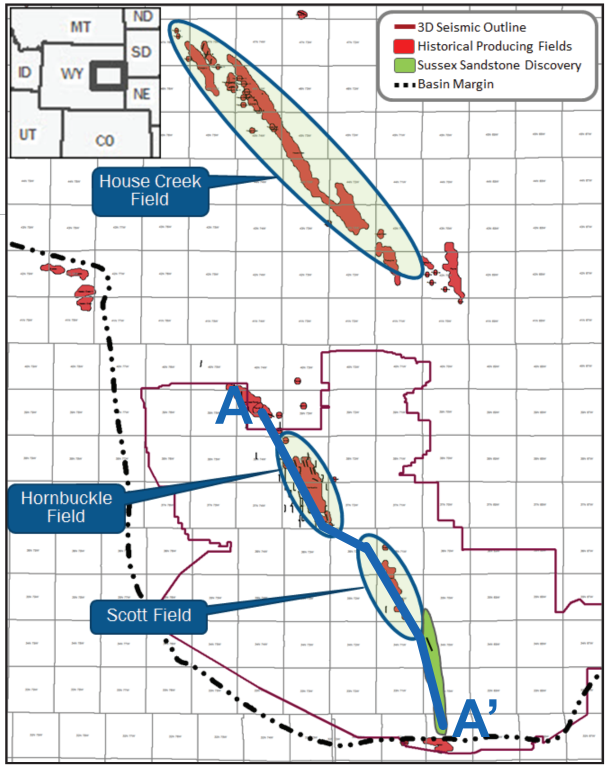
Powder River Basin

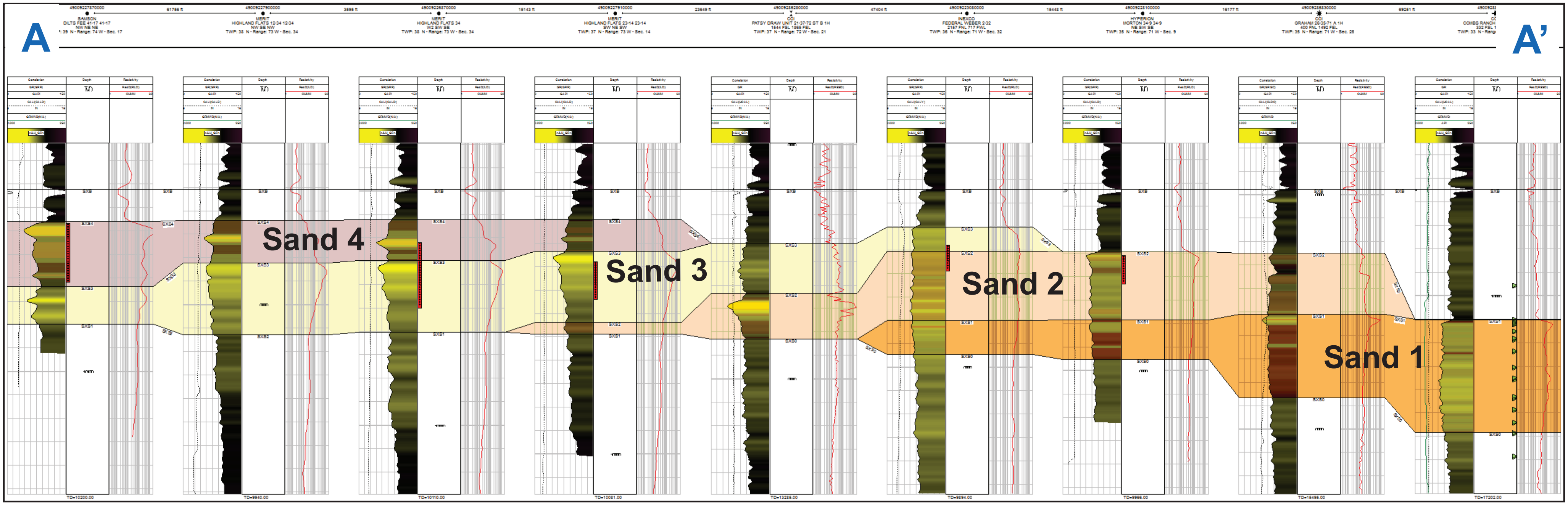


Chesapeake ENERGY

SUSSEX SANDSTONE: CROSS SECTION

- Stacked sand bodies
- Oldest sandstones deposited in SE
- Sourced by underlying over-pressured Niobrara
- Reservoir geometry identified using 3D amplitude maps and seismic inversion



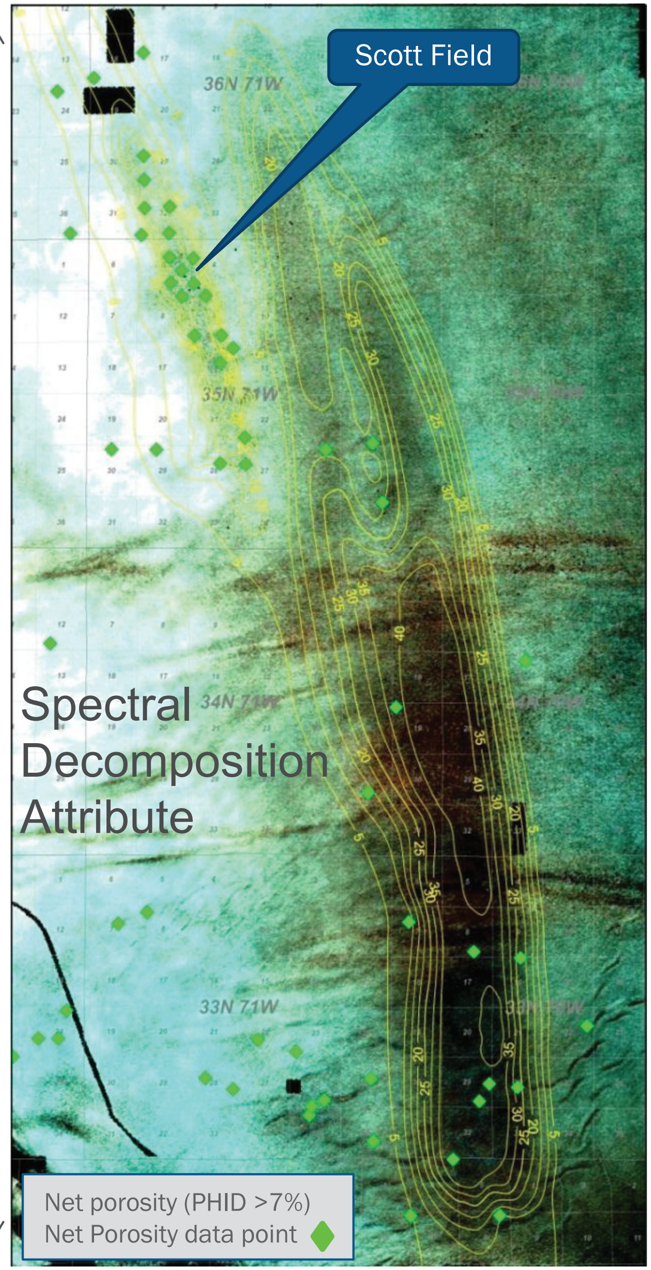


Chesapeake ENERGY

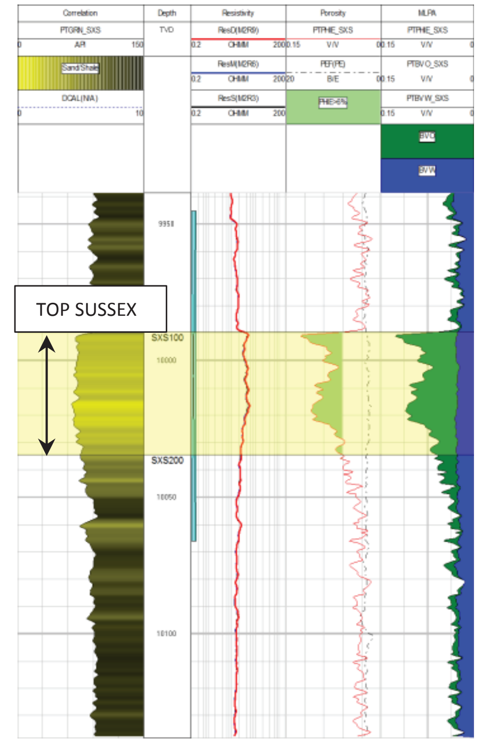
SUSSEX SANDSTONE: SEISMIC INVERSION

- Spectral Decomposition
  > Detects porous fluid filled sands
- Shows a stronger anomaly than Scott Field
  > Implies thicker fluid filled sand

~24 miles



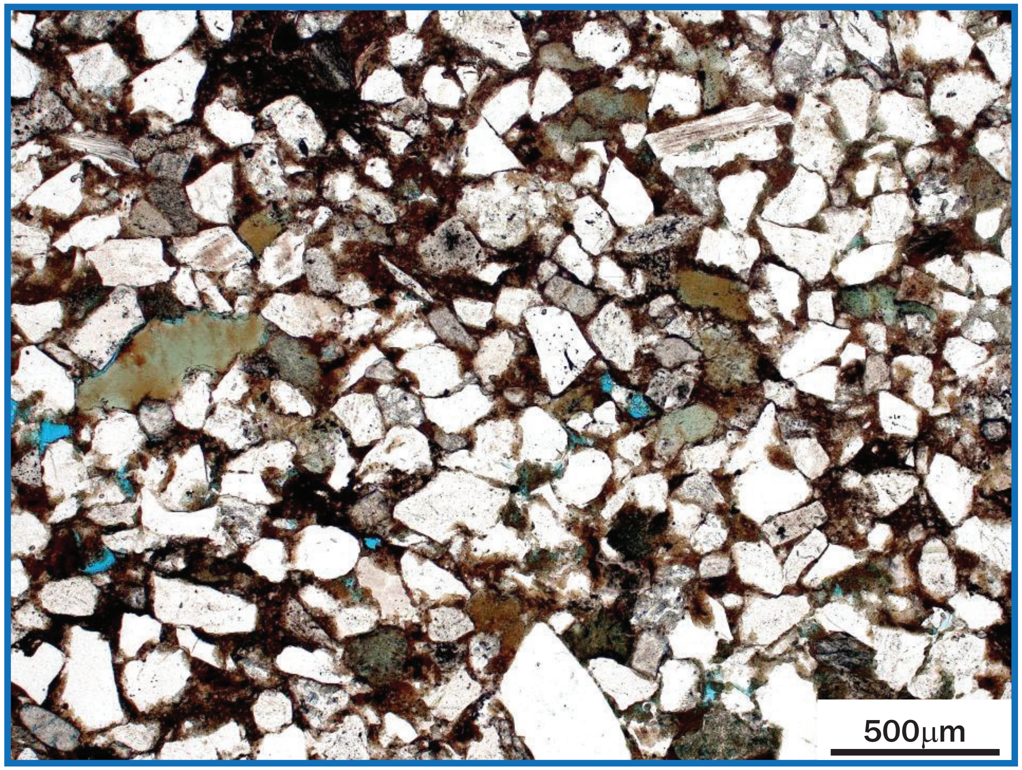
Sussex Type Log

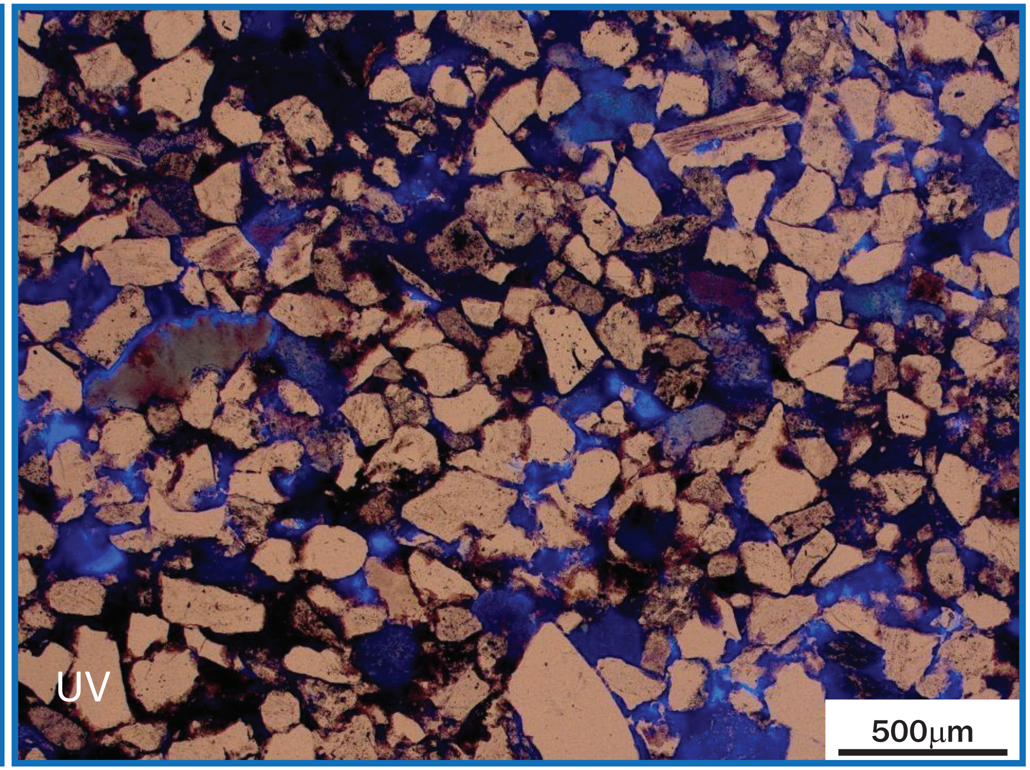


Chesapeake ENERGY

SUSSEX SANDSTONE: CORE ANALYSIS

- Reservoir quality
  - > Microporosity fluoresces under UV light
  - > Porosity – 9.5% BV





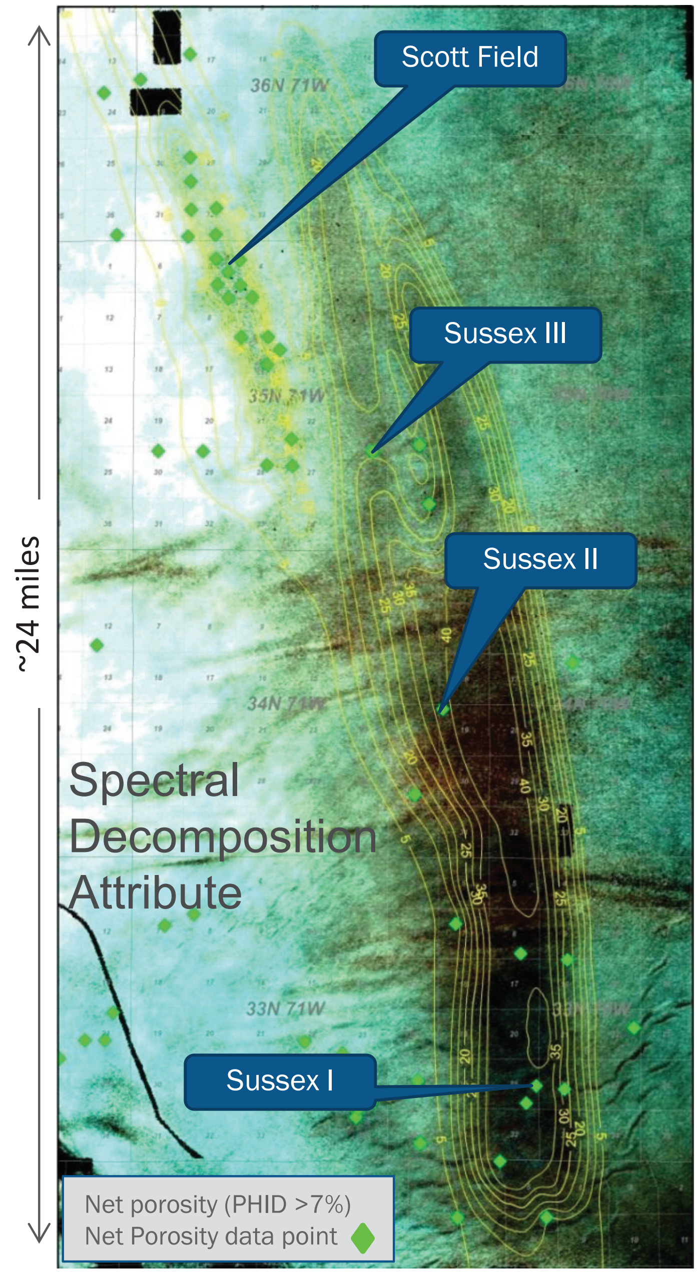
Sussex Core
50X

Chesapeake ENERGY

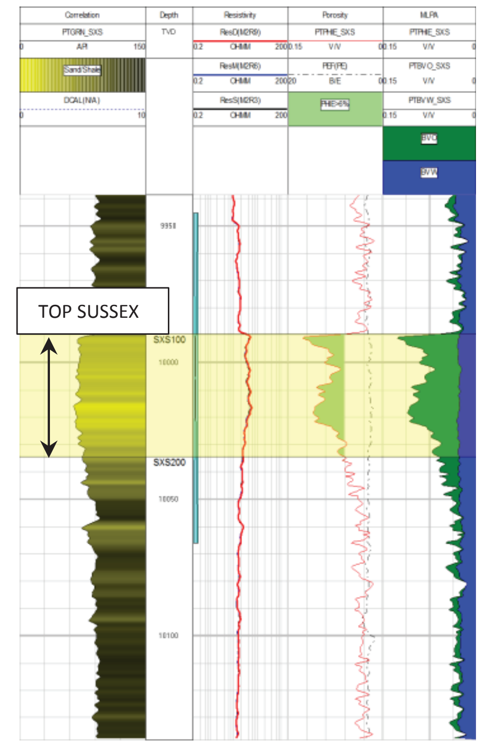
SUSSEX SANDSTONE: EXPLORATION RESULTS

Discovery and Initial Tests

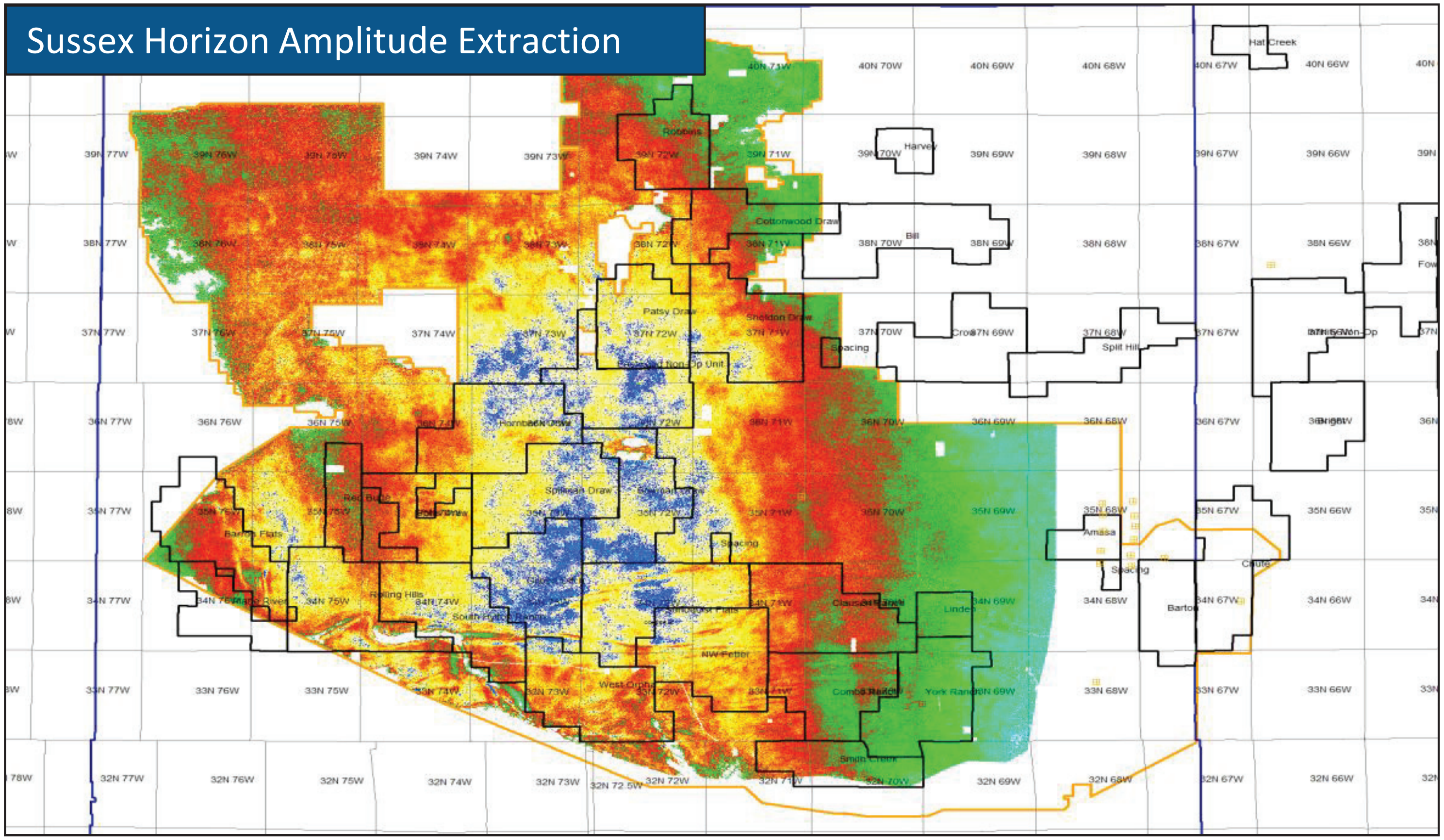
- Estimated gross EURs 250 - 500 mboe/well
- Sussex I
  - > Peak rate: 2,650 boe/d
- Sussex II
  - > Peak rate: 1,405 boe/d
- Sussex III
  - > Currently drilled to total depth, expect completion in June

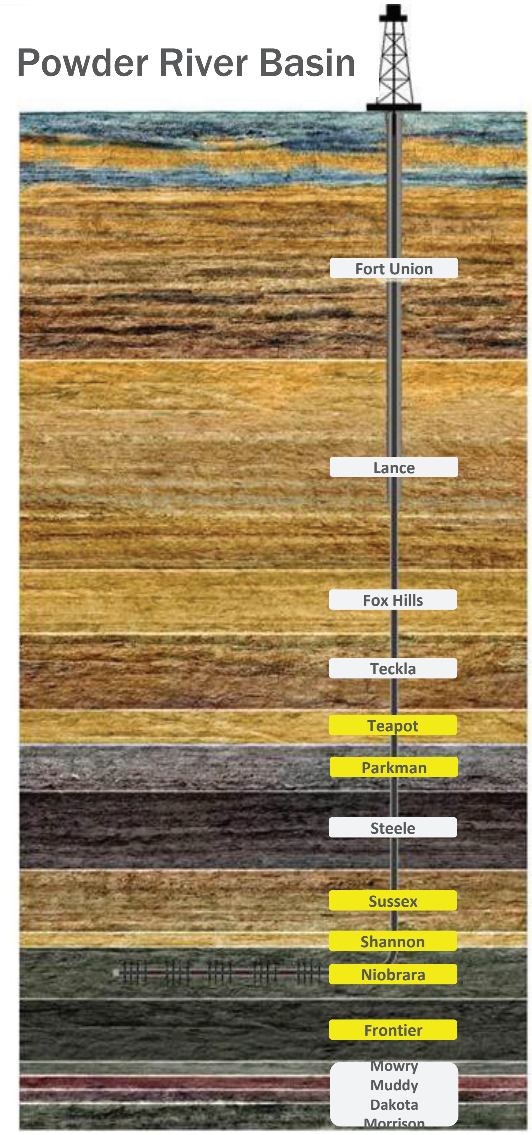


Sussex Type Log



EXPLORATION GROWTH OPPORTUNITIES: POWDER RIVER BASIN





>1.3 billion boe

Gross recoverable resource
(12% recovery factor)

Chesapeake ENERGY

GEOSCIENCE EXPERTISE WILL UNLOCK GROWTH OPPORTUNITIES

Chesapeake ENERGY

UNLOCKING VALUE

DOUG LAWLER

PRESIDENT, CHIEF EXECUTIVE OFFICER AND DIRECTOR

APPLYING OUR BUSINESS STRATEGIES

FINANCIAL DISCIPLINE

- Balance capital expenditures with cash flow from operations
- Divest noncore assets and noncore affiliates
- Reduce financial and operational risk and complexity
- Achieve investment grade metrics

PROFITABLE AND EFFICIENT GROWTH FROM CAPTURED RESOURCES

- Develop world-class inventory
- Target top-quartile operating and financial metrics
- Pursue continuous improvement
- Drive value leakage out of operations

Chesapeake ENERGY

CHESAPEAKE CORE VALUES

INTEGRITY & **TRUST**

RESPECT

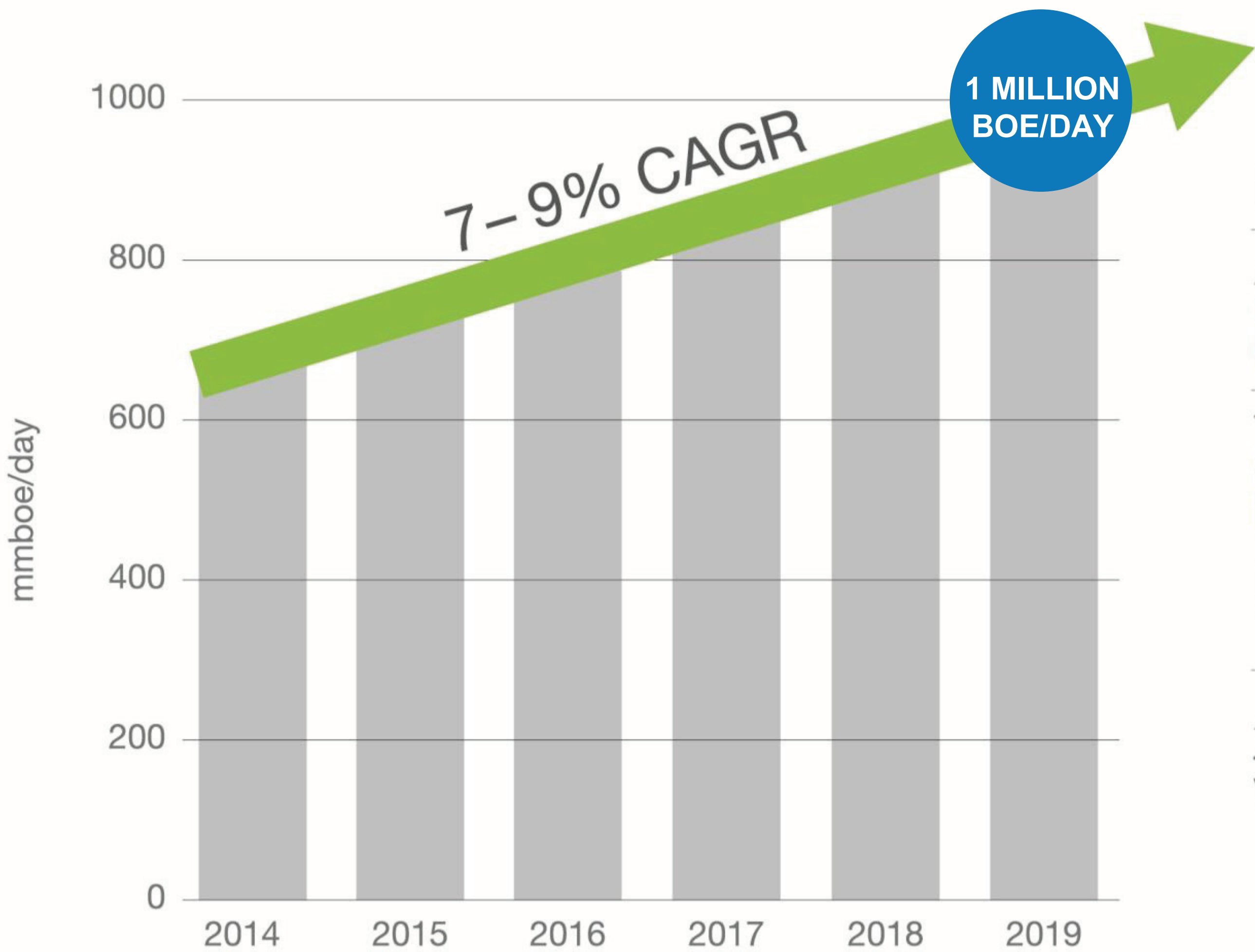
TRANSPARENCY & **OPEN COMMUNICATION**

COMMERCIAL FOCUS

CHANGE **LEADERSHIP**

Chesapeake ENERGY

5-YEAR PREVIEW – FOCUSED ON VALUE DELIVERING GROWTH



2015 PROJECTED PREVIEW

ADJUSTED **PRODUCTION GROWTH**(1)	**7 – 10%+**
TOTAL **CAPITAL EXPENDITURES** INCLUDES $500 CAPITALIZED INTEREST ($mm)	**$5,500 – $6,000**

2015 **CASH FLOW** WILL BE **BALANCED**

(1) Growth ranges based on midpoint of company Outlook issued on 5/16/2014.

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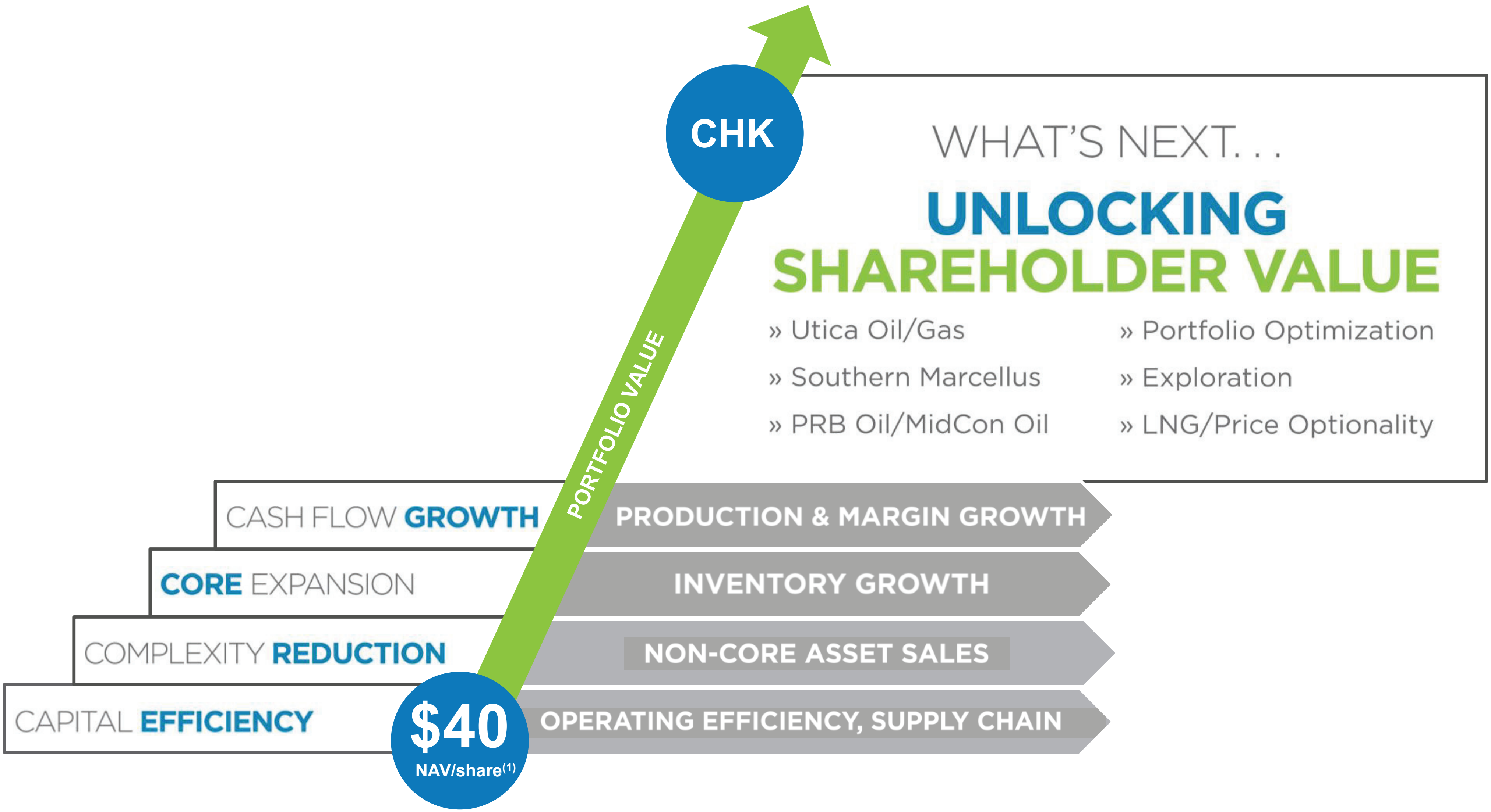
NET ASSET VALUE AND UPSIDE POTENTIAL



(1) Based on commodity prices of $4.50 and $90.00 for natural gas and oil, respectively, >20,000 risked drilling locations, net debt, NCI and other liabilities of $13 billion for a total net asset value of $32 billion.

Chesapeake ENERGY