2010 Institutional Investor and Analyst Meeting

October 13, 2010
Oklahoma City, OK

NATURAL GAS: FUELING AMERICA'S FUTURE

Meeting Agenda

8:00 am	Meeting Agenda: Jeff Mobley, SVP – Investor Relations and Research
8:05 am	Operations Overview: Steve Dixon, COO Jeff Fisher, SVP – Production
9:00 am	Natural Gas Shale Plays: John Sharp, VP – Geoscience, Southern Division
10:00 am	Anadarko Basin Plays: Scott Sachs, VP – Geoscience, Northern Division
10:30 am	Eagle Ford Shale Play: Skye Callantine, Geoscience Manager, South Texas
11:00 am	Permian and Rockies Plays: Steve Dixon, COO
11:30 pm	Midstream & Natural Gas Special Projects: Mike Stice, CHK SVP – Natural Gas Projects and CEO of CHKM
12:00 pm	Lunch
12:15 pm	Strategic Overview: Aubrey McClendon, CEO Financial Overview: Marc Rowland, CFO
2:00 pm	Closing

Meeting Objectives

- Demonstrate the skill and efficiency CHK has achieved in its industry-leading, low-cost natural gas shale plays
- Share the science and process behind CHK's shift to liquids-rich plays over the past three years
- Showcase the substantial opportunity set that CHK has built in liquids-rich plays, which provides decades of future high margin production growth
- Illustrate CHK's flexibility to shift capital from natural gas to liquids-rich plays
- Highlight the advantages of CHK's vertically integrated operations
- Provide an overview of CHK's strategic and financial strategy
- Quantify the value proposition of investing in CHK securities

Certain Reserve & Production Information

- The Securities and Exchange Commission requires natural gas and oil companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of natural gas and oil that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. In this presentation, we use the terms "risked and unrisked unproved resources" to describe Chesapeake's internal estimates of volumes of natural gas and oil that are not classified as proved reserves but are potentially recoverable through exploratory drilling or additional drilling or recovery techniques. These are broader descriptions of potentially recoverable volumes than probable and possible reserves, as defined by SEC regulations. Estimates of unproved resources are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of actually being realized by the company. We believe our estimates of unproved resources, both risked and unrisked, are reasonable, but such estimates have not been reviewed by independent engineers. Estimates of unproved resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.
- Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Although we believe the forecasts are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions and data or by known or unknown risks and uncertainties.

Forward-Looking Statements

- This presentation includes “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 give our current expectations or forecasts of future events. They include estimates of our natural gas and oil reserves and resources, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned asset sales, budgeted capital expenditures for drilling and acquisitions of leasehold and producing property, and other anticipated cash outflows, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. 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. 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 assumptions or by known or unknown risks and uncertainties.
- Factors that could cause actual results to differ materially from expected results are described under "Risks Related to our Business" in our Prospectus Supplement filed with the U.S. Securities and Exchange Commission on August 10, 2010. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; the availability of capital on an economic basis, including through planned asset monetization transactions, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures; inability 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 and oil sales, the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations; a reduced ability to borrow or raise additional capital as a result of lower natural gas and oil prices; drilling and operating risks, including potential environmental liabilities; legislative and regulatory changes adversely affecting our industry and our business; general economic conditions negatively impacting us and our business counterparties; transportation capacity constraints and interruptions that could adversely affect our cash flow; and losses possible from pending or future litigation.
- We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this presentation, and we undertake no obligation to update this information.

Corporate Information

Chesapeake Headquarters

6100 N. Western Avenue
Oklahoma City, OK 73118
Web site: www.chk.com

CHK LISTED NYSE

FORTUNE 100 BEST COMPANIES TO WORK FOR 2010

Other Publicly Traded Securities	CUSIP	Ticker
7.625% Senior Notes due 2013	#165167BY2	CHKJ13
9.5% Senior Notes due 2015	#165167CD7	CHK15K
6.25% Senior Notes due 2017	#027393390	N/A
6.50% Senior Notes due 2017	#165167BS5	CHK17
6.875% Senior Notes due 2018	#165167CE5	TBD
7.25% Senior Notes due 2018	#165167CC9	CHK18A
6.625% Senior Notes due 2020	#165167CF2	TBD
6.875% Senior Notes due 2020	#165167BU0	CHK20
2.75% Contingent Convertible Senior Notes due 2035	#165167BW6	CHK35
2.50% Contingent Convertible Senior Notes due 2037	#165167BZ9/165167CA3	CHK37/CHK37A
2.25% Contingent Convertible Senior Notes due 2038	#165167CB1	CHK38
4.5% Cumulative Convertible Preferred Stock	#165167842	CHK PrD
5.0% Cumulative Convertible Preferred Stock (Series 2005B)	#165167826	N/A
5.75% Cumulative Convertible Preferred Stock	#165167776/U16450204	N/A
5.75% Cumulative Convertible Preferred Stock (Series A)	#165167784/U16450113	N/A

Corporate Contacts:

Jeffrey L. Mobley, CFA
Senior Vice President –
Investor Relations and Research
(405) 767-4763
jeff.mobley@chk.com

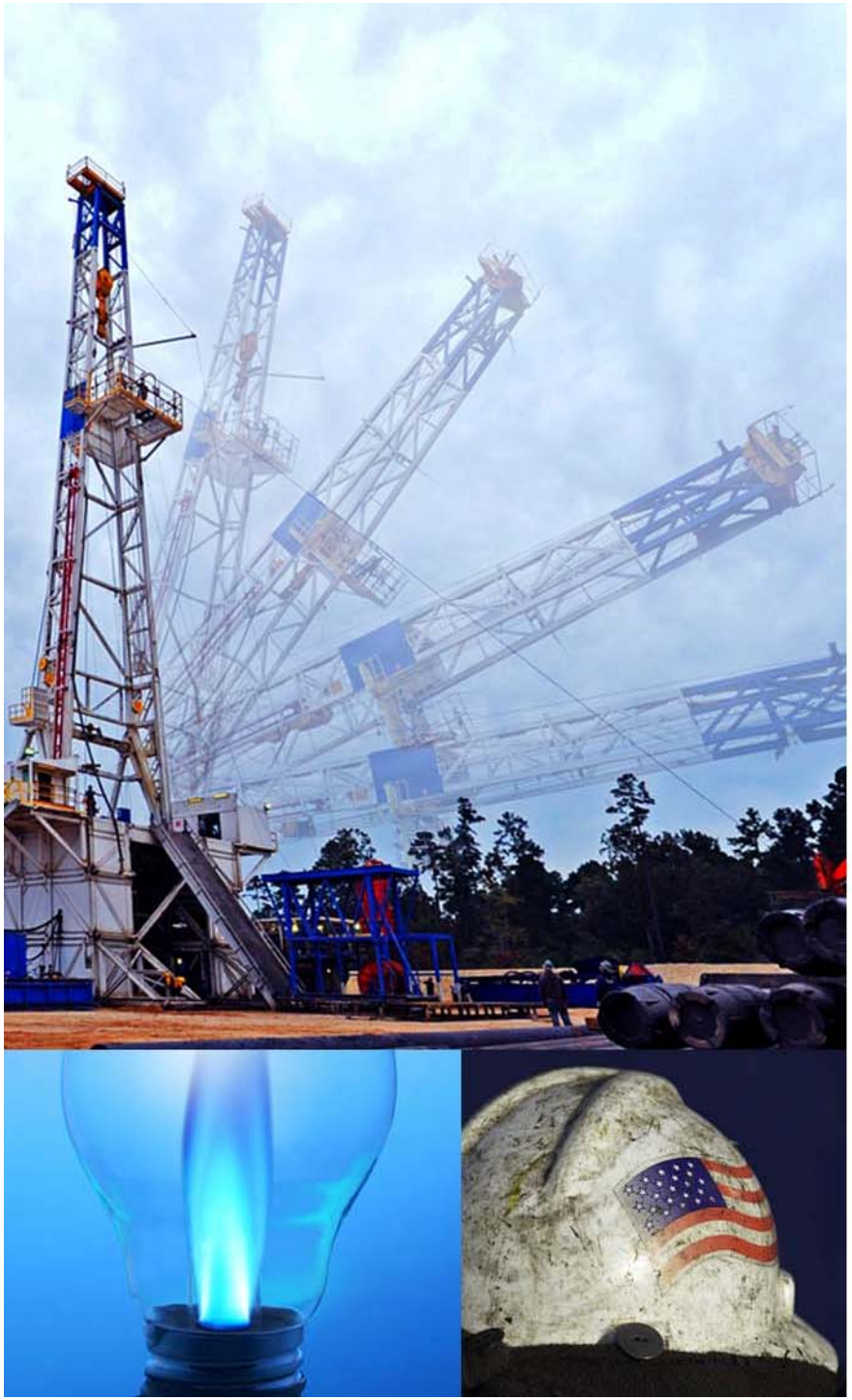
John J. Kilgallon
Manager – Investor Relations
and Research
(405) 935-4441
john.kilgallon@chk.com

Marcus C. Rowland
Executive Vice President and
Chief Financial Officer
(405) 879-9232
marc.rowland@chk.com

TWITTER.COM/CHESAPEAKE FACEBOOK.COM/CHESAPEAKE YOUTUBE.COM/CHESAPEAKEENERGY

Operations Overview

Steve Dixon, EVP – Operations and COO
Jeff Fisher, SVP – Production



CHK Overview

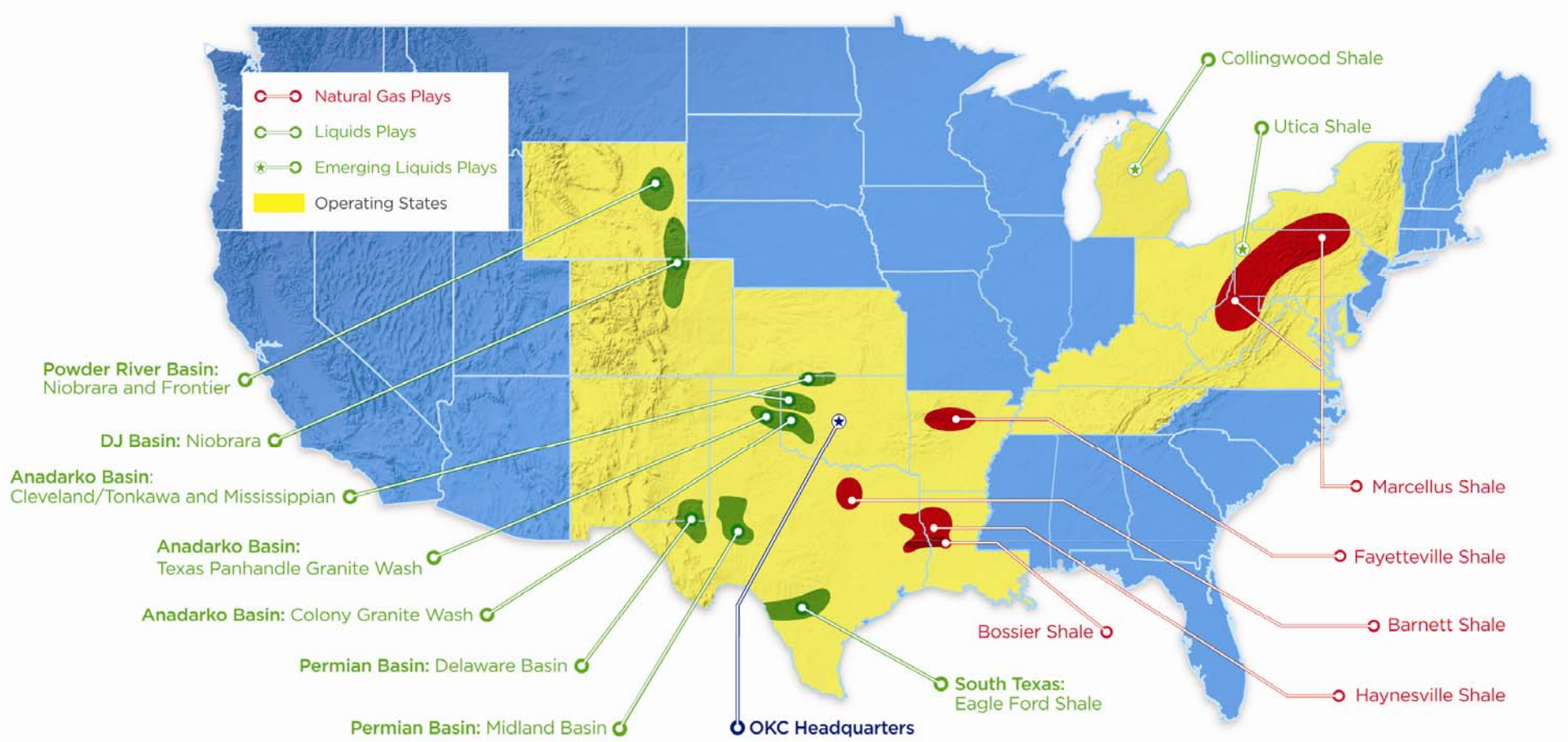
CHK Overview

- **Second-largest producer of U.S. natural gas**
  - 2Q'10 natural gas production of 2.497 bcf/d, total company production of 2.789 bcfe/d
- **Most active driller in U.S.**
  - 140 operated rigs currently, ~85 non-operated rigs & ~15 info only rigs; collector of ~20% of all daily drilling information generated in the U.S. (~25% in our areas of interest)
    - — 68% of 2010 drilling capex in natural gas plays and 32% in liquids-rich plays
    - — Shifting capital spending mix between natural gas plays and liquids-rich plays to ~50% by year-end 2012
- **Consistent production growth – 21 consecutive years of sequential production growth**
  - Projecting increases of ~13%, ~18% and ~12% in '10, '11 and '12 or ~2.8, ~3.3, and ~3.7 bcfe/d, respectively (after asset sales)
    - — Production growth from liquids ~60%, ~80% and ~20% in '10, '11 and '12, respectively
- **Best assets in the industry**
  - ~16.1 tcfe of proved reserves; targeting 22-24 tcfe by 2012(1)(2)
  - ~99 tcfe of risked unproved resource potential (~241 tcfe of unrisked unproved resource potential)
    - — >10-year inventory of ~40,000 net drilling locations(2)
  - PXP, BP, STO, TOT and CEO JVs validate asset quality directly
- **Unparalleled inventory of U.S. onshore leasehold and 3D seismic**
  - ~13.9 mm net acres of U.S. onshore leasehold and ~25.5 mm acres of 3D seismic data

Data above incorporates:
- CHK's Outlook dated 10/12/10
- Risk disclosure regarding unproved resource estimates appears on page iii

(1) Based on 10-year average NYMEX strip pricing at 6/30/10; 15.5 tcfe using SEC pricing
(2) As of 6/30/10

CHK's Operating Areas



Low-risk, U.S. onshore asset base; Not exposed to economic, geopolitical or technological risks internationally or in the Gulf of Mexico

CHK's Operational Accomplishments – We Like to Stay Ahead of the Pack

- #1 driller of wells in the U.S.; 140 rigs drilling out of ~1,671 total U.S. land rigs, or 8%
- #1 driller in the U.S. during the past 20 years; ~11,000 wells
- #1 in the world in horizontal well drilling over the past 20 years; ~4,000 wells
- #1 in the world in horizontal shale drilling over the past 10 years; ~3,100 wells
- #2 producer of U.S. natural gas (pro forma for XOM/XTO); 2.5 bcf/day in 2Q '10
- #1 producer of shale gas in the world; >1.8 bcf/day average in 9/10
- #3 owner of U.S. natural gas proved reserves, 14.2 tcf
- #1 owner of natural gas shale in the U.S.; ~140 tcfe of unrisked net unproved resources(1)
- #1 combined owner of U.S. onshore leasehold (~14 mm net acres) and 3D seismic (>25 mm net acres)
- #1 owner of leasehold in Big 6 U.S. shale plays: Marcellus, Haynesville, Bossier, Barnett, Fayetteville and Eagle Ford; ~3.4 mm net acres(2)
- #1 inventory of shale core rock data; analyzed in CHK's proprietary Reservoir Technology Center
- #1 JV sponsor: Sold assets for $12.8 billion to some of world's largest energy companies
  - Still retain 75% in Barnett, 80% in Haynesville, 75% in Fayetteville, 67.5% in Marcellus and 66.7% in Eagle Ford
- #1 hedging track record in industry; $5.4 billion in realized gains since 2001

1) Includes: Marcellus, Haynesville, Bossier, Barnett and Fayetteville
2) Bossier shale acreage overlaps with Haynesville Shale acreage and is excluded from the shale play sub-total to avoid double counting of acreage

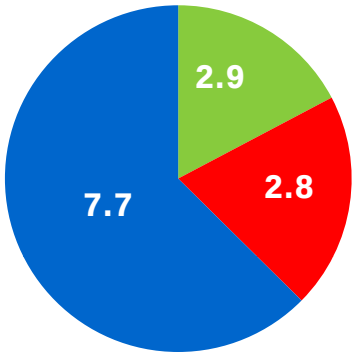
CHK's track record of operational achievements during the past 20 years has been unique

America's #1 Resource Base

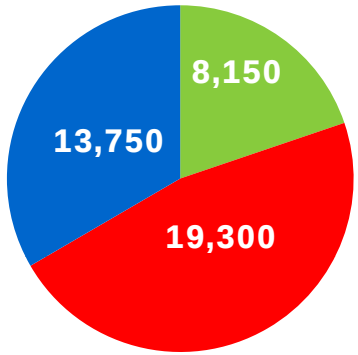
- CHK is exceptionally well positioned for long-term profitable growth
- Largest combined inventories of U.S. leasehold and 3D seismic data in the industry
- 2.8 bcfe of daily production 2Q '10, 89% gas
- 16.1 tcfe of proved reserves[1][2], 92% gas
- 99 tcfe of risked unproved resources[1][2]
  - 241 tcfe of unrisked unproved resources[1][2]
- 13.9 million net acres of leasehold[1]
- 25.5 million acres of 3D seismic data
- >10-year inventory of ~40,000 net drillsites[1]

Natural Gas Shale Plays[3]
Unconventional Liquids-Rich Plays[4]
Other Conventional and Unconventional Plays

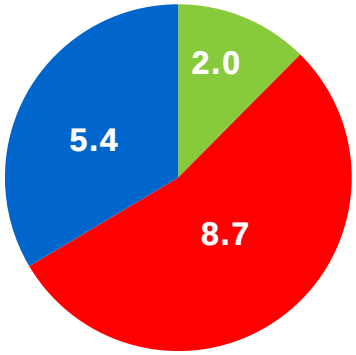
Net Acreage
~13.9 million acres



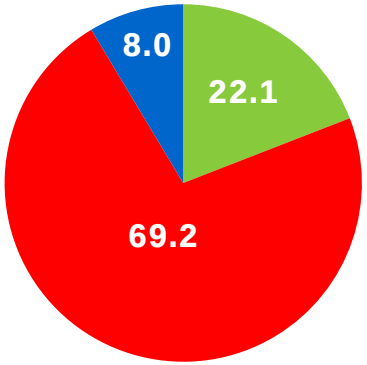
Drillsites
~40,000 net drillsites



Proved Reserves
~16.1 tcfe

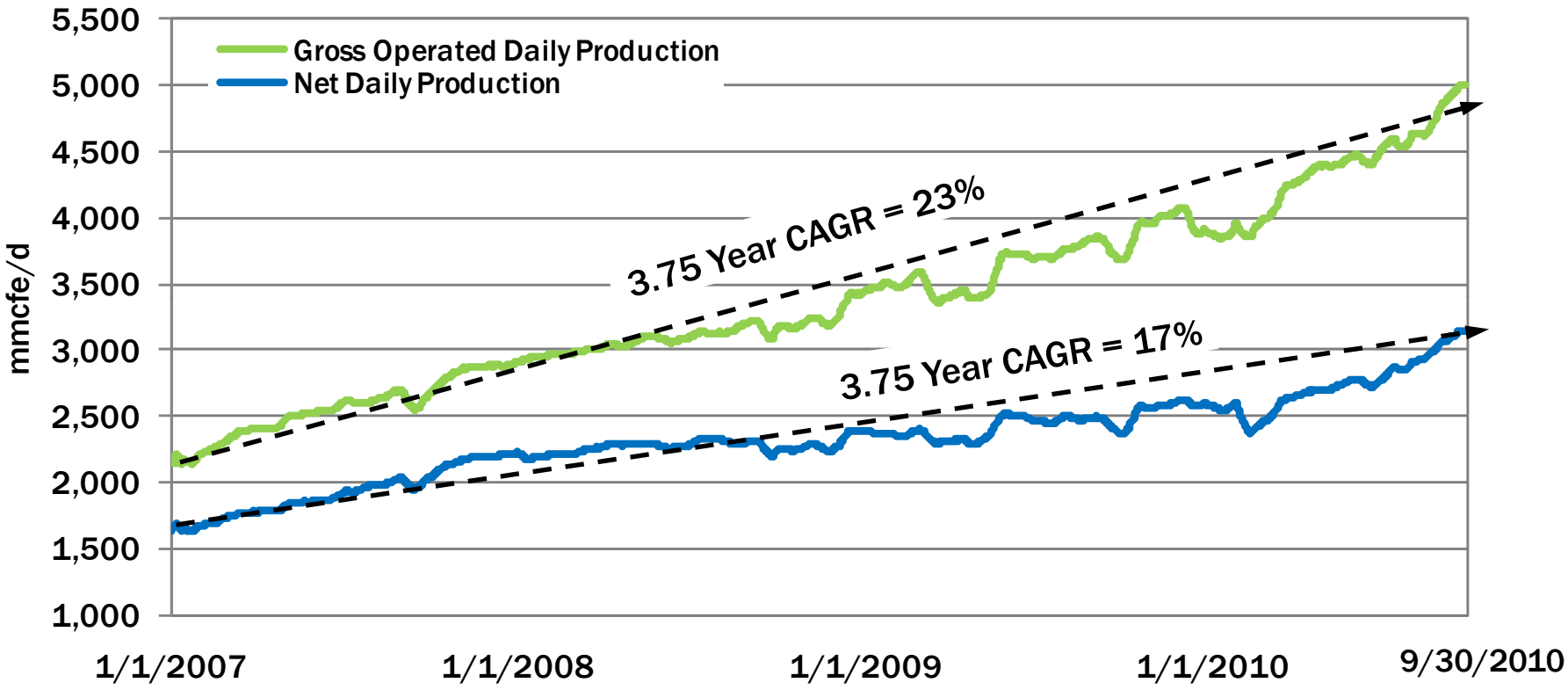


Risked Unproved Resources
~99 tcfe



1) Risk disclosure regarding unproved resource estimates appears on page iii
2) Based on 10-year average NYMEX strip pricing at 6/30/2010; 15.5 tcfe of proved reserves using SEC pricing
3) Consists of the Marcellus, Haynesville, Barnett, Fayetteville, and Bossier shale plays
4) Consists of the Eagle Ford Shale, Anadarko Basin, Permian Basin and Rocky Mountain plays

Consistent Production Growth

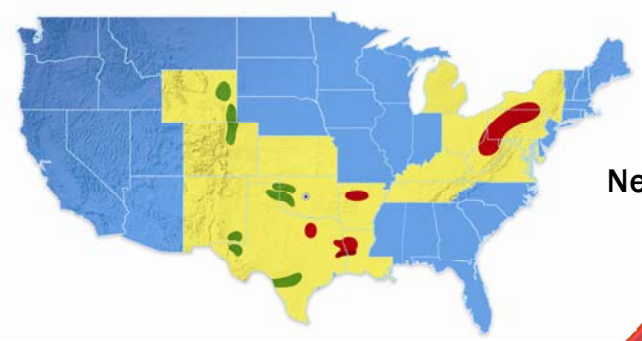


- Despite sales of 2.2 tcfe of proved reserves for proceeds of ~$5.8 billion and ~445 mmcfe/d of production, since 1/07, CHK's net production has increased at a 17% CAGR

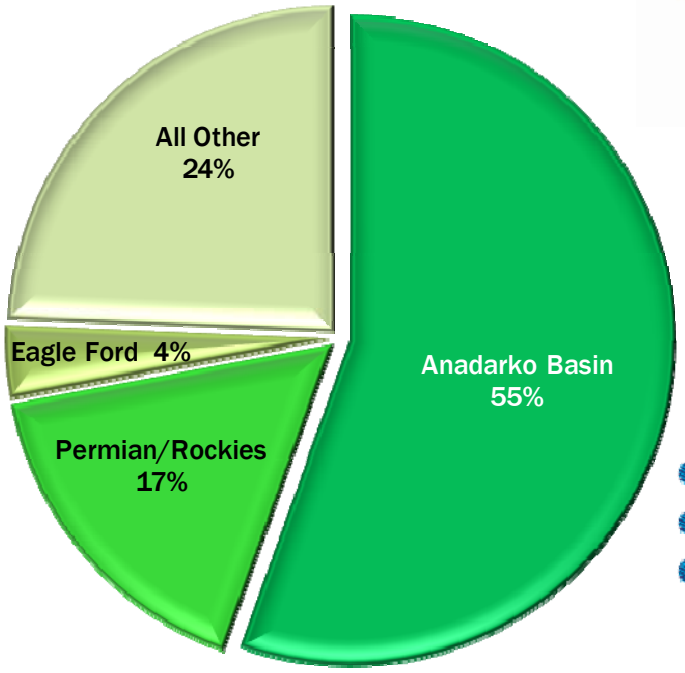
CHK is a remarkable growth story whose best 20 years lie ahead!

Production Mix

Latest Production Milestone – September 26, 2010
Net Production of 3.2 bcfe/d



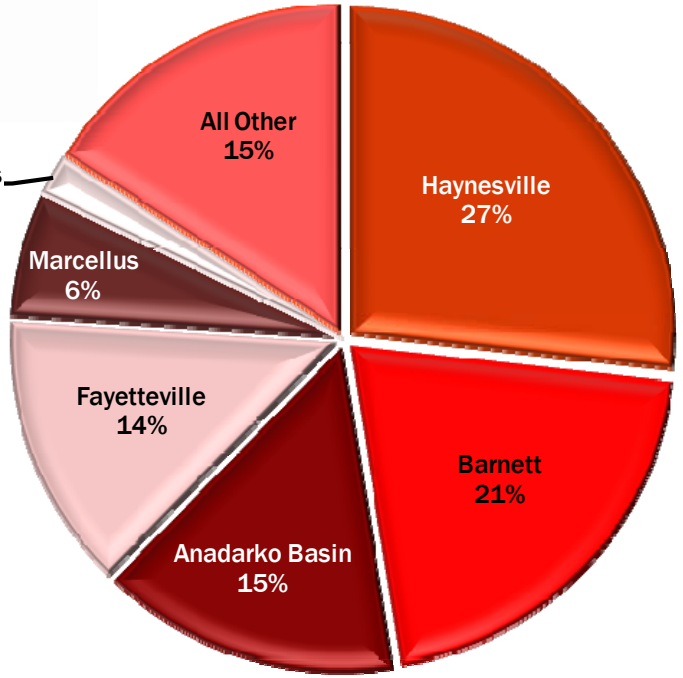
Net Liquids Production of 56 mbbls/d



- 2.9 bcf/d gas - 90%
- 35 mbbls/d oil - 6%
- 21 mbbls/d NGL's - 4%

3.2 bcfe/d

Net Gas Production of 2.9 bcf/d



Targeting liquid production of 100 mbbls/d by YE '12 , and 200 mbbls/d by YE '15

Top 20 U.S. Natural Gas Producers

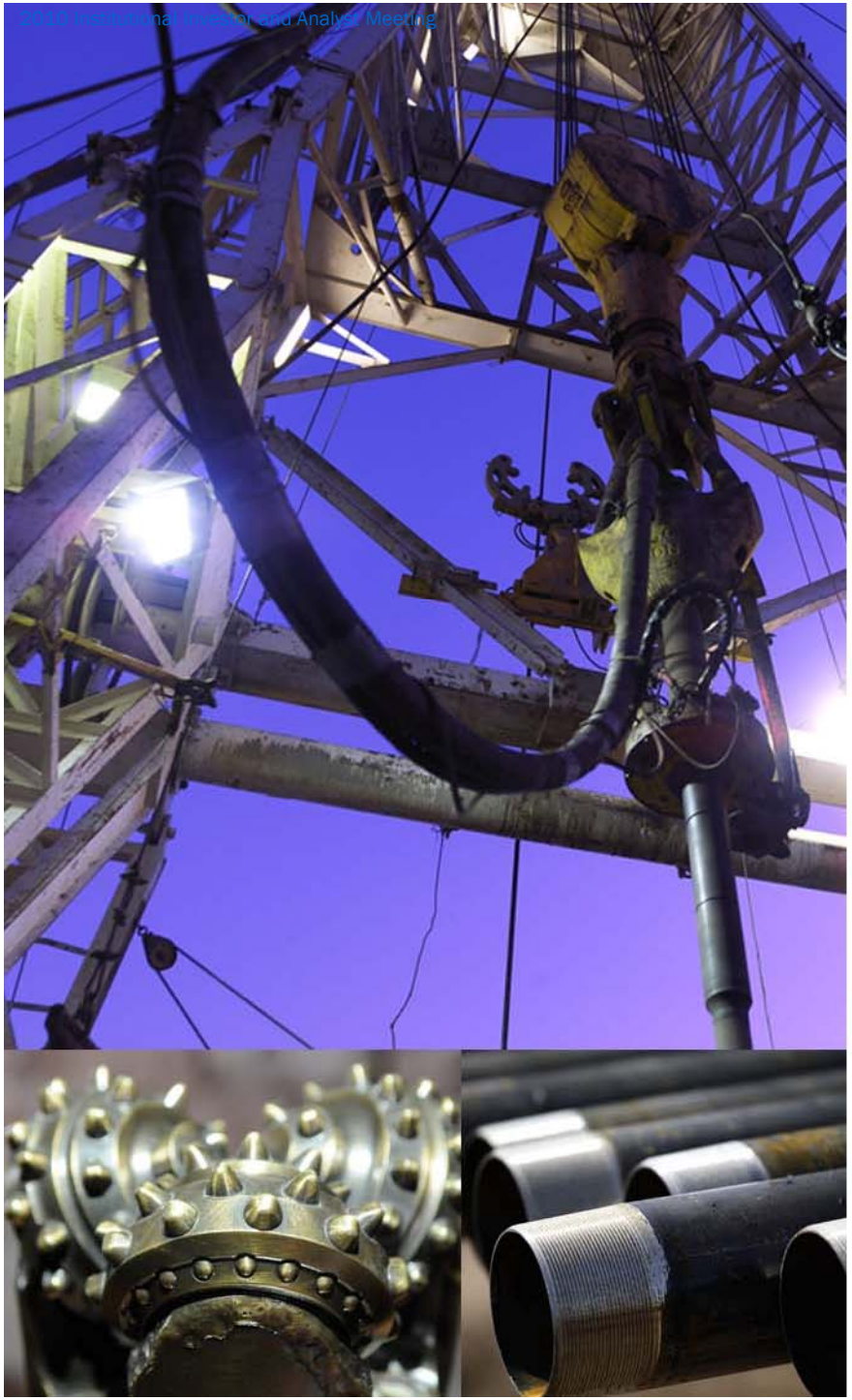
	Company[3]	Ticker	Daily U.S. Natural Gas Production[1][2] 2Q'10	1Q'10	2Q'09	2Q'10 vs. 1Q'10 % Change	2Q'10 vs. 2Q'09 % Change	2009 Reported U.S. Net Proved Natural Gas Reserves	RP Ratio[4]	Proved U.S. Natural Gas Reserves Ranking	U.S. Gas Rigs Drilling on 9/24/10[5]	U.S. Gas Rigs Drilling on 8/29/08[5]	U.S. Gas Rigs % Drilling Change Since 8/29/2008
1.	ExxonMobil[6]	XOM	3,810	3,733	3,595	2.1%	6.0%	24,189	17	1	66	78	(15%)
2.	Chesapeake	CHK	2,497	2,328	2,245	7.3%	11.2%	13,510	15	3	98	143	(31%)
3.	Anadarko	APC	2,324	2,393	2,336	(2.9%)	(0.5%)	7,764	9	6	22	36	(39%)
4.	BP	BP	2,240	2,221	2,339	0.9%	(4.2%)	15,216	19	2	12	20	(40%)
5.	Devon	DVN	1,982	1,952	2,129	1.5%	(6.9%)	8,127	11	5	45	66	(32%)
6.	EnCana	ECA	1,850	1,805	1,581	2.5%	17.0%	5,713	8	8	48	53	(9%)
7.	ConocoPhillips	COP	1,822	1,799	2,095	1.3%	(13.0%)	10,742	16	4	13	35	(63%)
8.	Chevron	CVX	1,317	1,378	1,395	(4.4%)	(5.6%)	2,698	6	14	3	6	(50%)
9.	Shell	RDS	1,145	1,115	1,056	2.7%	8.4%	2,258	5	18	15	13	15%
10.	Williams	WMB	1,110	1,102	1,180	0.7%	(5.9%)	4,255	11	9	19	32	(41%)
11.	EOG	EOG	1,069	1,043	1,139	2.5%	(6.1%)	6,350	16	7	46	52	(12%)
12.	Southwestern	SWN	1,077	997	815	8.0%	32.2%	3,650	9	11	17	22	(23%)
13.	Occidental	OXY	681	675	621	0.9%	9.7%	2,799	11	12	0	4	(100%)
14.	El Paso	EP	680	671	652	1.3%	4.3%	2,052	8	19	9	11	(18%)
15.	Apache	APA	675	672	663	0.4%	1.8%	2,438	10	17	12	14	(14%)
16.	Petrohawk	HK	599	609	456	(1.7%)	31.4%	2,700	12	13	21	19	11%
17.	Ultra	UPL	599	539	467	11.1%	28.2%	3,737	17	10	10	15	(33%)
18.	Newfield	NFX	564	520	497	8.4%	13.5%	2,605	13	15	10	23	(57%)
19.	QEP Resources	QEP	525	514	477	2.2%	10.1%	2,525	13	16	13	26	(50%)
20.	Noble	NBL	414	384	394	7.8%	5.1%	1,534	10	20	11	13	(15%)
	Totals / Average		26,979	26,450	26,131	2.0%	3.2%	124,862			490	681	(28%)
	Other Producers										498	864	(42%)
	Total										988	1,545	(36%)

1) Based on 2Q'10 company reports
2) In mmcfe/day
3) Independents in blue, majors in black, pipelines in green
4) Based on annualized production
5) Source: Smith Bits, a Schlumberger Company; CHK is internal count
6) Pro forma for XOM/XTO acquisition which closed on June 25, 2010. XTO U.S. natural gas production is as of 1Q'10

Top 20 U.S. Liquids Producers

	Company[3]	Ticker	Daily U.S. Liquids Production[1][2] 2Q'10	1Q'10	2Q'09	2Q'10 vs. 1Q'10 % Change	2Q'10 vs. 2Q'09 % Change	2009 Reported U.S. Net Proved Liquids Reserves	RP Ratio[4]	Proved U.S. Liquids Reserves Ranking	U.S. Oil Rigs Drilling on 9/24/10[5]
1.	BP	BP	581	665	661	(12.6%)	(12.1%)	3,073	14	1	4
2.	Chevron	CVX	488	504	467	(3.2%)	4.5%	1,361	8	4	6
3.	ExxonMobil[6]	XOM	441	473	470	(6.8%)	(6.1%)	2,004	12	2	7
4.	ConocoPhillips	COP	382	403	422	(5.2%)	(9.5%)	685	5	7	9
5.	Occidental	OXY	269	269	267	0.0%	0.7%	1,606	16	3	9
6.	Shell	RDS	231	248	278	(6.9%)	(16.9%)	710	8	6	0
7.	Anadarko	APC	196	202	157	(3.0%)	24.8%	760	11	5	10
8.	Devon	DVN	123	120	122	2.2%	1.1%	559	12	8	14
9.	Apache	APA	101	96	94	6.2%	7.9%	524	14	9	10
10.	BHP	BHP	100	109	88	(8.2%)	14.4%	204	6	15	0
11.	EOG	EOG	85	80	65	6.8%	30.9%	280	9	11	30
12.	Hess	HES	85	84	68	1.2%	25.0%	249	8	12	10
13.	Denbury	DNR	66	45	38	48.2%	73.9%	193	8	16	0
14.	Marathon	MRO	57	58	64	(1.7%)	(10.9%)	170	8	17	7
15.	Whiting	WLL	52	48	41	10.0%	26.5%	224	12	13	17
16.	ENI[7]	E	50	55	46	(10.4%)	7.8%	110	6	19	1
17.	Chesapeake	CHK	49	43	35	13.2%	40.5%	124	7	18	42
18.	Pioneer	PXD	47	45	43	4.1%	9.2%	316	18	10	15
19.	Plains	PXP	45	45	49	0.4%	(7.0%)	214	13	14	0
20.	Kinder Morgan	KMP	45	46	47	(2.2%)	(4.9%)	87	5	20	2
	Totals / Average		3,494	3,638	3,521	(4.0%)	(0.8%)	13,451			193
	Other Producers										388
	Total										581

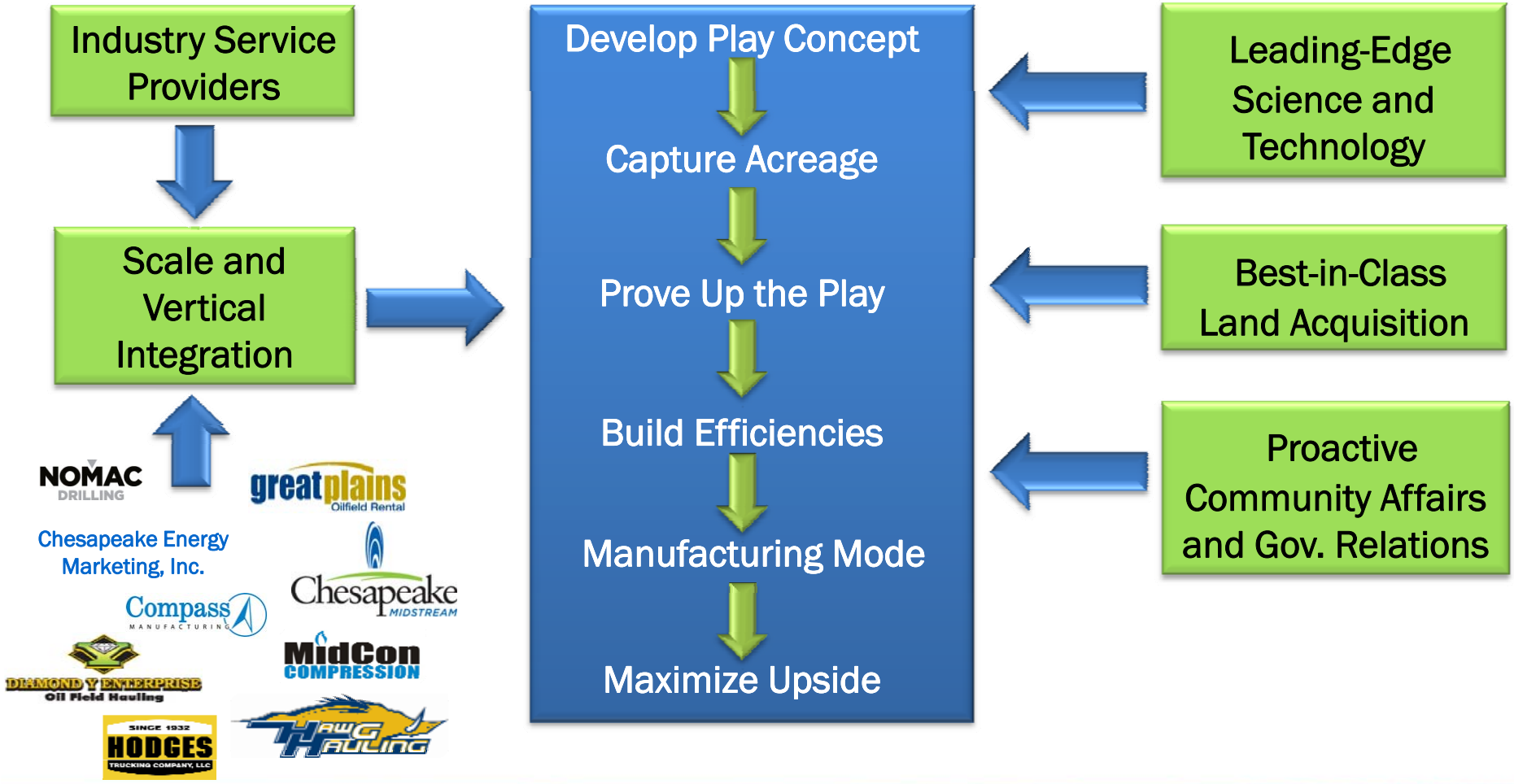
1) Based on 2Q'10 company reports
2) In mbbls/day
3) Independents in blue, majors in black, pipelines in green
4) Based on annualized production
5) Source: Smith Bits, a Schlumberger Company; CHK is internal count
6) Pro forma for XOM/XTO acquisition which closed on June 25, 2010
7) Applied yearly percentage regional split to quarterly production numbers



CHK Operational Excellence

CHK Operating Strategy

Top-tier resource plays lend themselves to continuous improvement



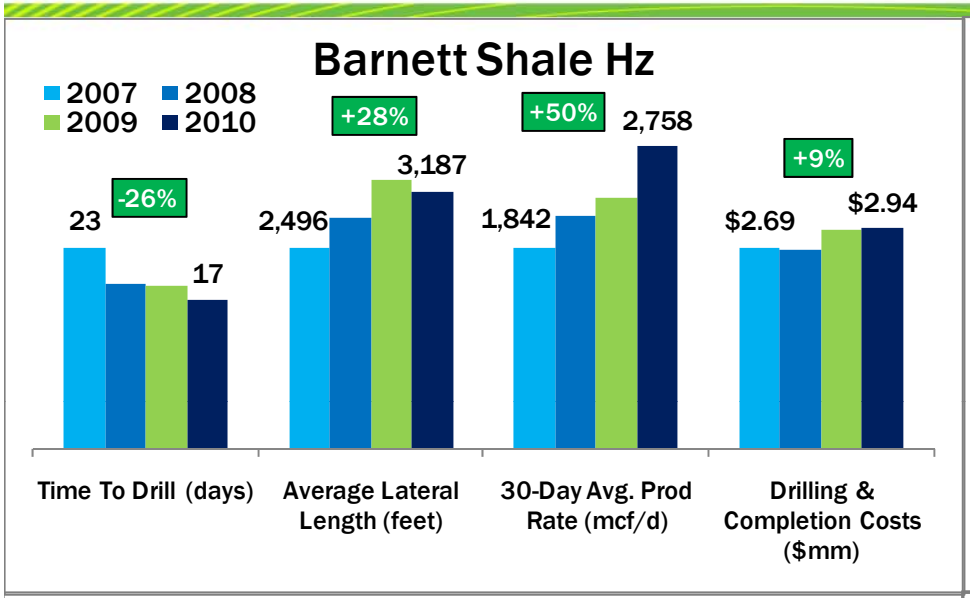
CHK's organizational structure allows it to be quick to market…yet its scale and commitment to technology also allows it to be a top-tier performer on operational metrics

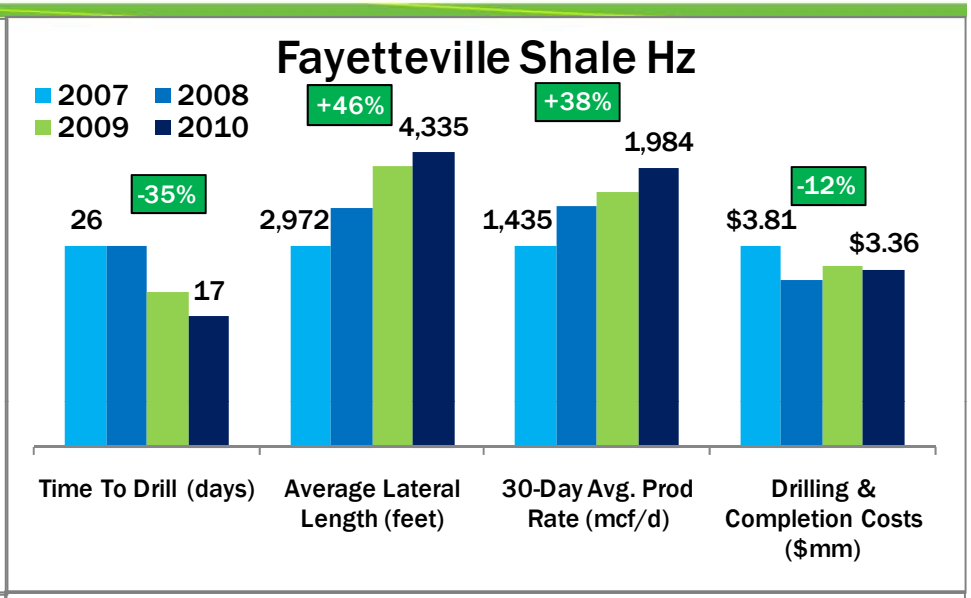
General Trends in CHK Resource Plays

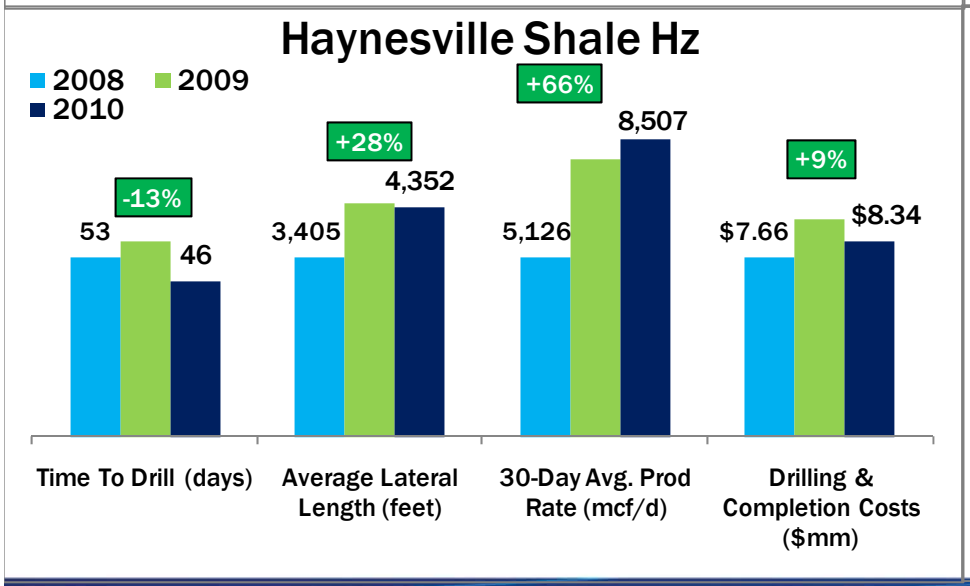
Drilling days	Experience and proper technology application decrease drilling days in lateral; play specific bit and motor
Rig efficiency	Reduced cycle time enables more wells per rig per year
Target zones	Geologic targets refined and lateral placement high-graded
Lateral length	Optimization of lateral length; strong EUR to completed lateral length relationship; focus on lowering $/ft
Drilling and Completion (D&C) costs	Gains made through experience and efficiency
Completion design	"Fine tuning" of completion designs for rock properties and sub-field areas improves EUR; focus on achieving maximum recovery and PV
Initial production rate	Improving with optimized completions and targeting within zone
EUR	Upward reserve "creep" with more production history as performance enhancements are achieved
Production methods	Optimization in production methods improves average well EUR and well performance prediction
Recovery factors & GIP	Recovery factors increase and GIP estimates rise with improved completion design and production methods
Logistics	Development strategies are streamlined to boost economics and cycle time; leverage work volume for favored pricing and "turn around time"
Infrastructure	Economics improve as infrastructure expands and marketing options increase

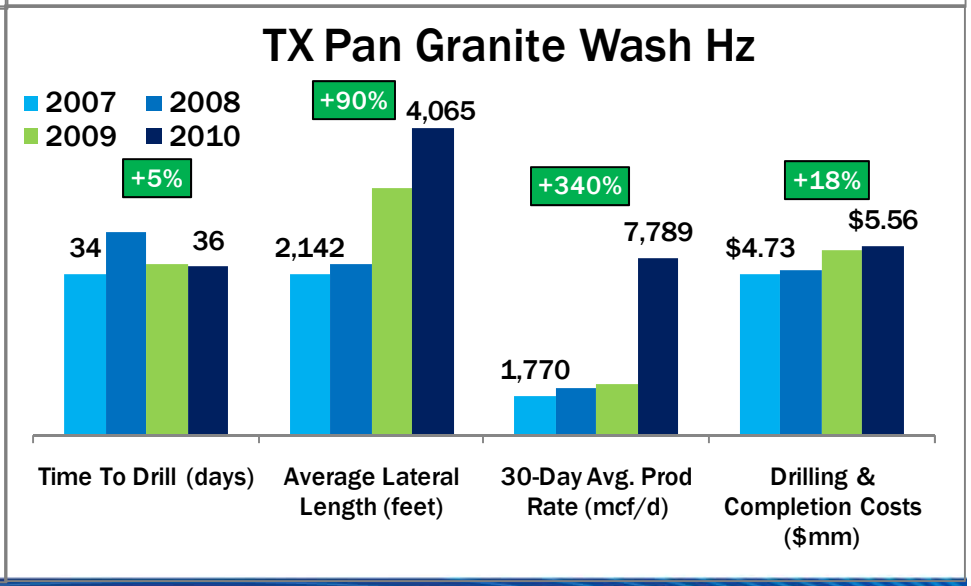
Improved cycle times, longer laterals, optimized completions and costs management are creating tremendous value

Operating Strategy and Capabilities are Adding Tremendous Value





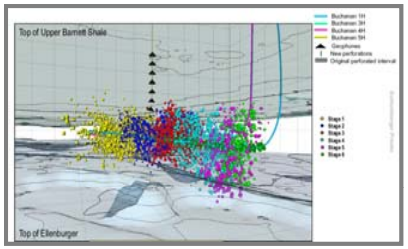




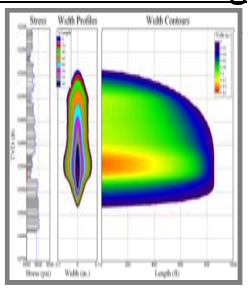
Implementing Leading-Edge Technology

- **Integrated technology approaches continue to drive improved performance**
- **Our technology teams and proprietary core lab are leading the way to new advancements to optimize field development…and economic results**
  - Understanding flow units
  - Lateral placement
  - Rock mechanics
  - Characterizing effective fracture behavior
  - Advanced well performance analysis
  - Production logging to understand completion efficiency
  - Micro-seismic and stimulated rock volume (SRV)
  - Geocellular modeling for permeability distributions
  - Reservoir simulation
  - Stress-sensitive and fluid-sensitive behaviors for reservoir and completions
  - Multiphase flow behavior
  - Multi-laterals
  - Data mining technologies

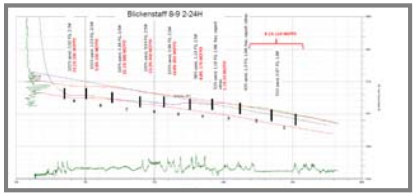
Stimulated Rock Volume



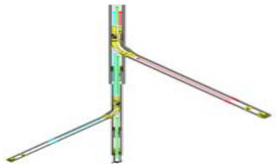
Fracture Modeling



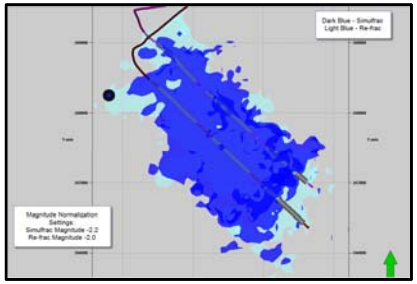
Production Logging



Multi-laterals



Reservoir Simulation



Advanced Well Performance Analysis

Data Metrics → Filter Crossplots → Identify Correlations → Test Economics = Optimized Results

Stimulation Design Analysis

Completion Data Metrics

a) Lateral length
b) Lateral orientation
c) Length per stage
d) # of stages
e) # of perforation intervals
f) # of clusters per stage
g) Perforation interval length
h) Cluster spacing
i) TVD
j) Total sand volume
k) Sand volume per perforation interval
l) Sand volume per foot of lateral
m) Total water volume
n) Water volume per perforation interval
o) Water volume per foot of lateral
p) Proppant concentration
q) Sand volume by sieve size
r) Fracture gradient

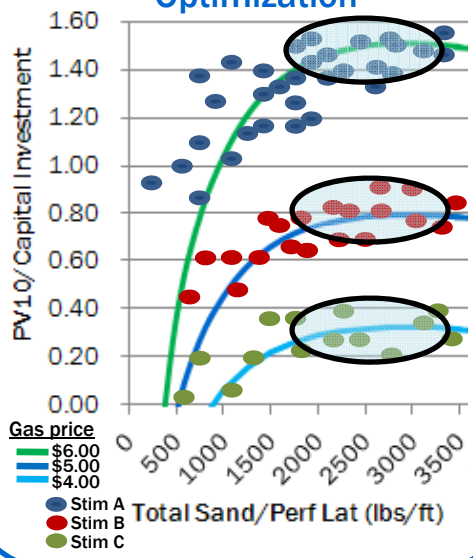
Performance Data Metrics

a) EUR
b) EUR per foot of lateral
c) Peak rate
d) Peak rate per foot of lateral
e) 12-month cumulative production
f) 24-month cumulative production

Reservoir/Geology Data Metrics

a) Permeability
b) Thickness
c) Kh
d) Free GIP
e) Absorbed GIP
f) GIP per foot of thickness
g) Geographic Area
h) Well spacing
i) # of faults in lateral
j) Seismaps

Economic Indicator

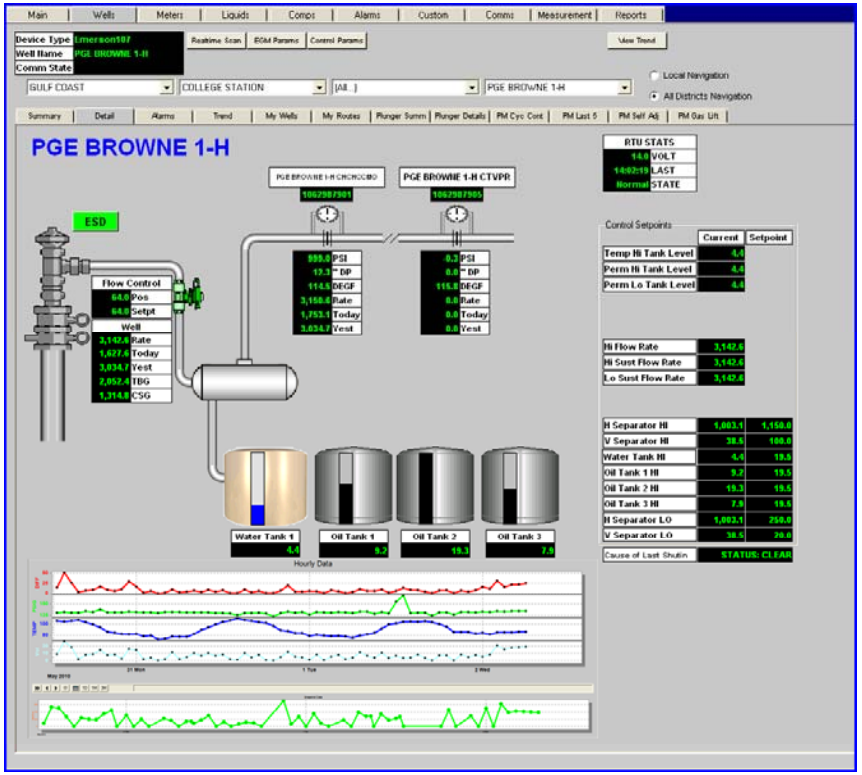


Data is key and CHK has the largest database in the industry by a wide margin

Operational Efficiency at All Levels

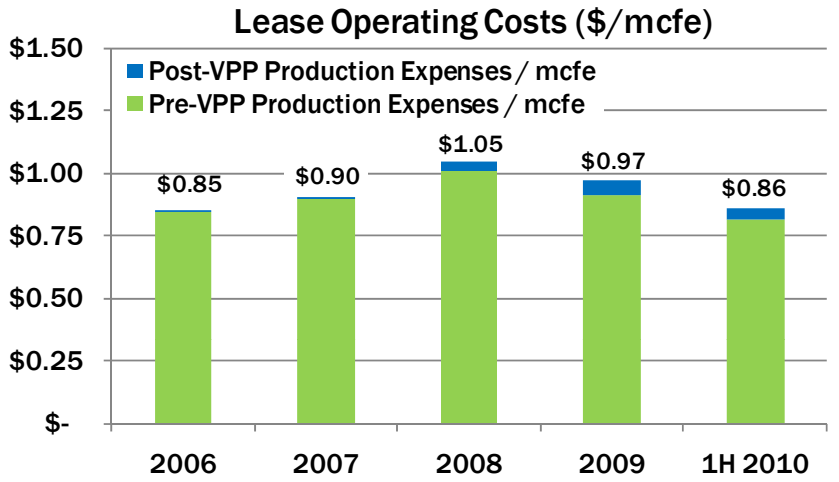
- **State-of-the-art field surveillance and control systems**
- **Covers 97% of CHK operated volumes**
- **Efficient operations and real-time data**
  - Accurate gas/liquids measurement
  - Remote callout/alarming
  - Remote operator intervention capability/shut-in
  - 24x7 Chesapeake Operations Center monitoring
  - Precise daily production information obtained within 24 hours
- **Safety and environmental controls**
  - Tank level overflow protection
  - Vessel over pressure protection
  - Integrity management
  - Water regulatory tracking

Well monitoring and control



Exceptional Operating Cost Control

- CHK commitment to efficiency has led to low lease operating costs and substantial improvements over the past two years
- Cost optimization initiatives and improving asset portfolio are helping drive unit costs down
- Exceptional performance in shale plays helps project returns in a challenging natural gas price environment
- Retained operating costs from seven VPPs has only increased corporate unit costs by ~$0.05/mcfe



CHK's Commitment to Safety

- **Proactive risk identification and resolution**
  - Pre-Job planning and frequent site inspections
  - Contractor selection and service quality reviews
  - Third party review of well designs
  - Performance auditing
- **Rigorous reporting and response**
  - Tracking of all injuries and incidents
  - Root cause investigations and reviews with senior management
- **Emergency response training**
  - Internal process design
  - Close interaction with local emergency responders
- **Development and disciplined use of Best Management Practices (BMPs)**
  - Site construction, well/facility designs and safety systems
- **Behavior Based Safety training**
  - Transitioning from a compliance culture to a belief culture
  - Personal accountability – "you see it, you own it"

ZERO incidents is the goal!

CHK's Commitment to the Environment

- **Spill Prevention, Control and Countermeasure (SPCC) plans**
  - Secondary containment for chemicals, oils and produced fluids
  - CHK utilizes a site management system to generate SPCC plans
- **Water management practices**
  - Improved sourcing methods
  - Recycling/reuse
- **Waste management**
  - Regional waste plans and audits
- **Air Quality**
  - Robust compliance system
  - Technical support team to implement regional solutions
- **Promoting the use of natural gas in America**
  - NGV's
  - Natural Gas powered rigs

Aqua Renew
CHESAPEAKE ENERGY'S WATER RECYCLING INITIATIVE

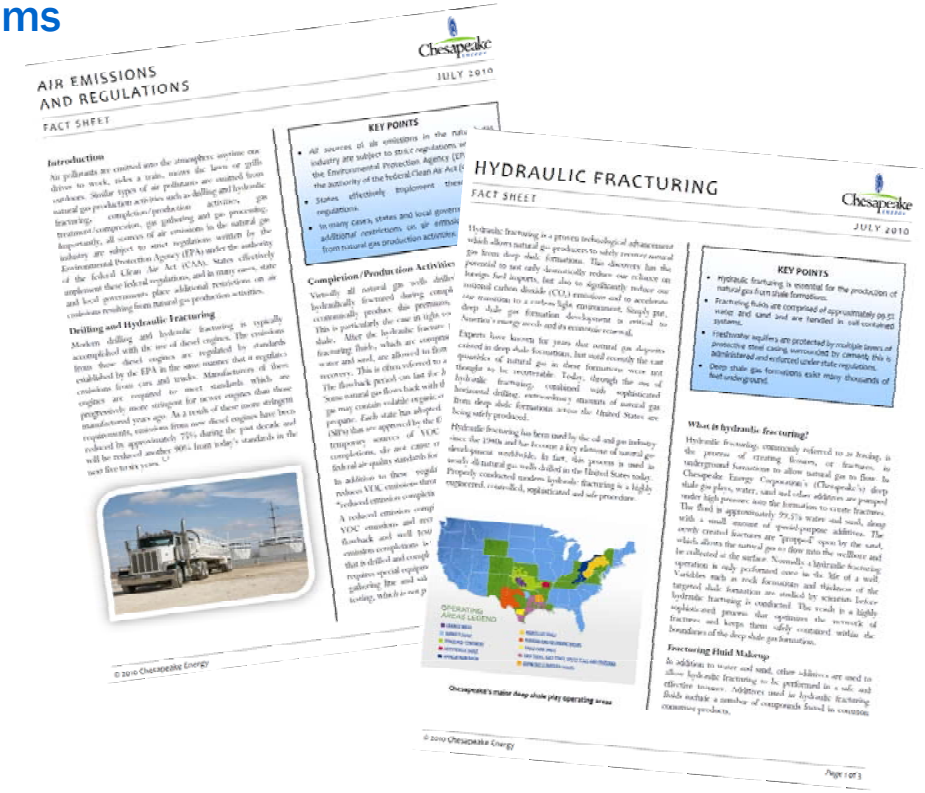
GreenFrac™

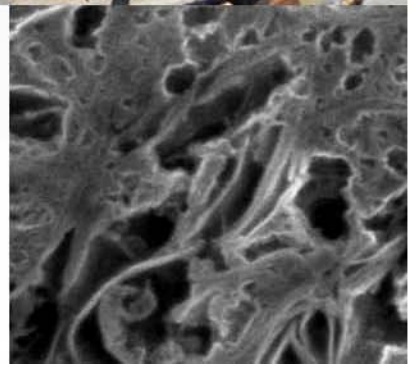
Implementing state-of-the-art environmental protection across our operations

Public Outreach and Collaboration

Operations and EH&S work together to develop educational resources:

- Coordinate and provide town hall meetings and rig tours
- Educational videos that describe the drilling and completion process
- Proactive disclosure and education programs
  - Hydraulicfracturing.com
  - Naturalgasairemissions.com
  - Naturalgaswaterusage.com
- Fact Sheets
  - Air emissions
  - Emergency response
  - Gas emissions and reduction
  - Greenhouse regulatory framework
  - Hydraulic fracturing
  - Water use





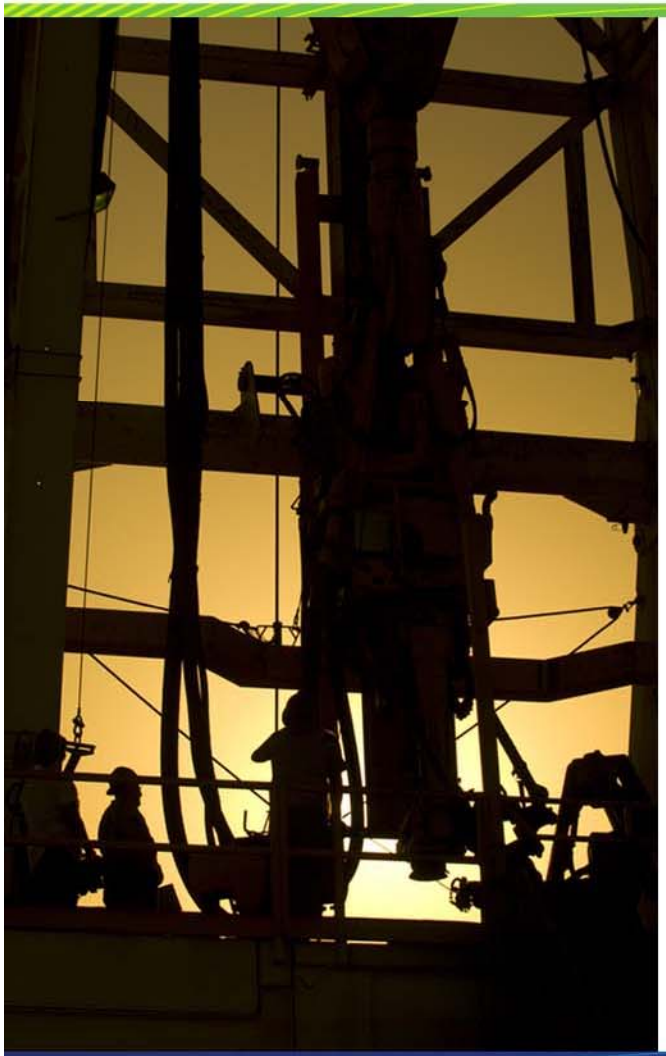
Chesapeake ENERGY

Cracking the Code in Unconventional Liquids-Rich Plays

CHK's Distinctive Advantages

- **Top 1 or 2 position in all 5 major natural gas shale plays provides an enormous head start in the shift to unconventional liquids plays**
- **CHK has built a top 1 or 2 position in every major unconventional liquids-rich play, except for the Bakken**
- **Integration of the CRTC, Geoscience, Petrophysical, Engineering and Operational teams within the unconventional group is unique**
  - Chesapeake's Reservoir Technology Center (CRTC) is a significant competitive advantage and has greatly enhanced CHK's speed of execution and reduced risk
    - CRTC is analyzing more shale core than the rest of the industry combined
  - CHK has built highly predictive petrophysical models
    - Model incorporates data from CRTC along with engineering, mechanical, geochemical and geological data
    - Has led to key discoveries in multiple natural gas and liquids-rich plays
- **CHK's substantial position in multiple unconventional plays results in a database of geologic and production information much larger than our competitors**
  - CHK has been able to capitalize on this superior data which gives us a distinct advantage over our competition

Big Oil on the Way to CHK



- Started transition in 2007 (note: CHK was early, not late to the unconventional oil game)
  - Announced discovery of Colony Granite Wash play in 1Q '08 and also disclosed new unconventional oil plays
- Quietly built leasehold positions in unconventional plays that would benefit from advancements in drilling and completion technologies
- 2008-2010: confirmed play concepts work
- Now have ~2.9 mm net acres in unconventional liquids-rich plays with ~3.7 Bboe of risked unproved resources and ~11 Bboe unrisked unproved resources
- Expect to increase liquids production to ~200,000 bbls/d, or ~25% of total production and ~35-40% of production revenue by YE 2015 through organic growth
- Continuing to evaluate other unconventional liquids-rich play concepts

Evolution of CHK's Unconventional Plays

Anadarko Basin

4Q '04*
Colony and TX PH
Granite Washes

Anadarko Basin

4Q '05
Cleveland/Tonkawa

Delaware and Midland Basins

4Q '06
Bone Spring

Anadarko Basin

1Q '07
Mississippian

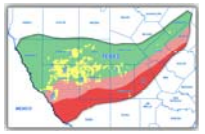
Delaware Basin

4Q '08
Avalon Shale

Rockies

4Q '08
Niobrara and Frontier

Eagle Ford Shale



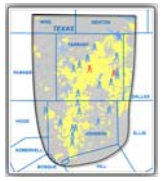
4Q '09

Big Oil

Others on the way

?

Barnett Shale

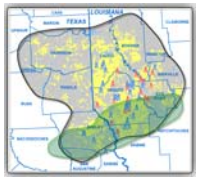


4Q '04

Fayetteville Shale

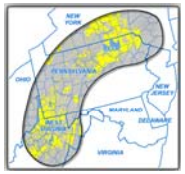
1Q '06

Haynesville Shale



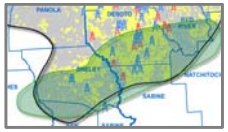
2Q '07

Marcellus Shale



3Q '07

Bossier Shale



2Q '09

Big Gas

* Dates indicate spud of first well

CHK is Transferring Expertise from Unconventional Gas to Liquids

Chesapeake ENERGY

Reservoir Simulation

Advanced Reservoir Modeling

Advanced Petrophysical Analysis

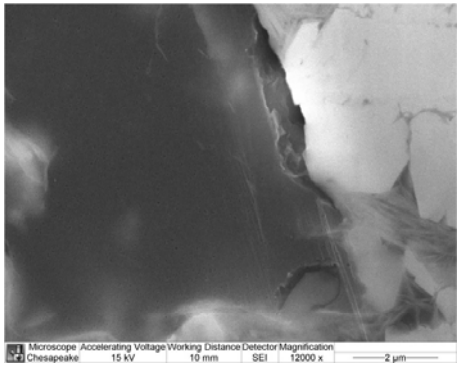
Fracture Property Analysis

Petrologic and Organic Geochemical Analysis

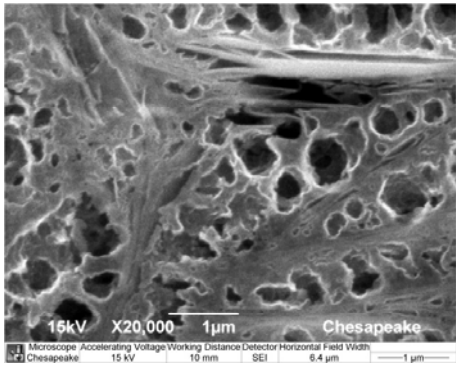
Rock Mechanics Analysis

Advances in Tight Oil Exploitation

Tight Sandstone/Limestone Member



Immature

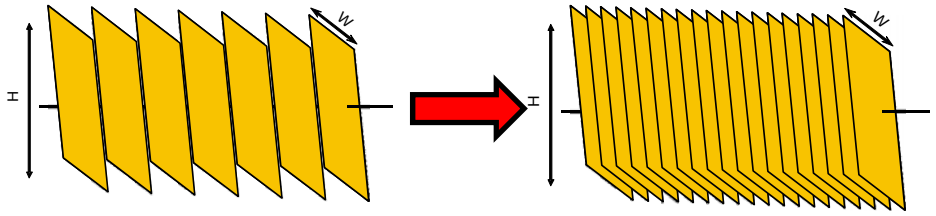


Mature

- Improved understanding of source-reservoir geometries and charging
- Improved understanding of role of kerogen thermal maturity and matrix permeability

Old Fracture Spacing:

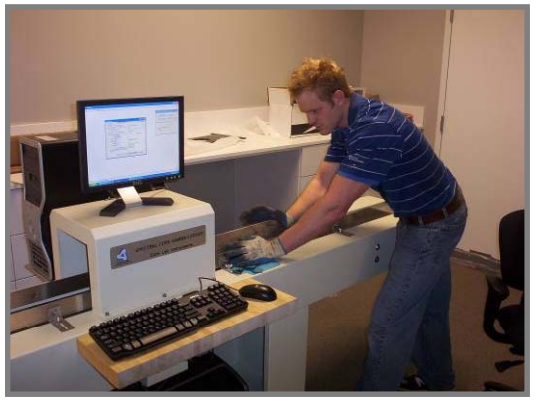
New Fracture Spacing:



- Improved fracture density leads to increased productivity without significant inter-fracture interference

Advanced PetroPhysical Analysis

- Tight rock analysis
- Porosity
- Permeability
- Water saturation
- Core spectral gamma log
- Bound water
- Mobile oil saturation
- Grain density
- Gas-filled porosity
- Bulk density



Spectral Core Gamma

Core Storage and Layout
(~6 miles of shale core)

High-speed Centrifuge

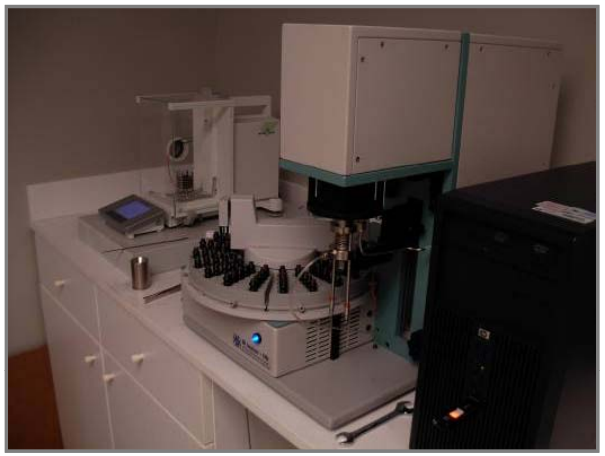
Tight Rock Permeameter

New, improved and larger building for CRTC under design; completion anticipated in 2012

Petrologic and Organic Geochemical Analysis

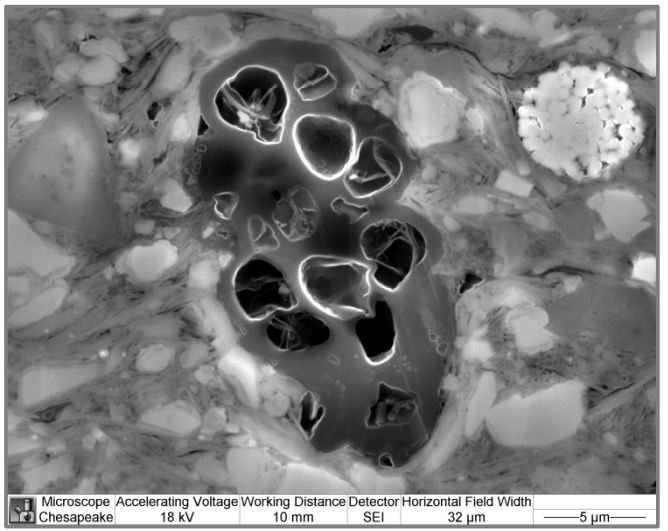
- Scanning Electron Microscope (SEM)
- Thin Section Petrographic Scopes
- Automated Multi-sample X-Ray Diffraction (XRD)
- Argon-ion milling (critical to imaging shales)
- LECO Total Organic Carbon
- Rock-Eval (Humble SRA)

Source Rock Analysis



X-ray Diffraction

SEM

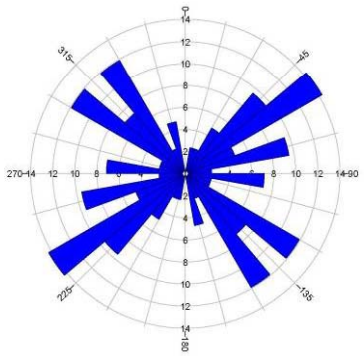


Argon-ion polished shale

Specialized Rock Mechanics Analysis and Fracture Property Analysis

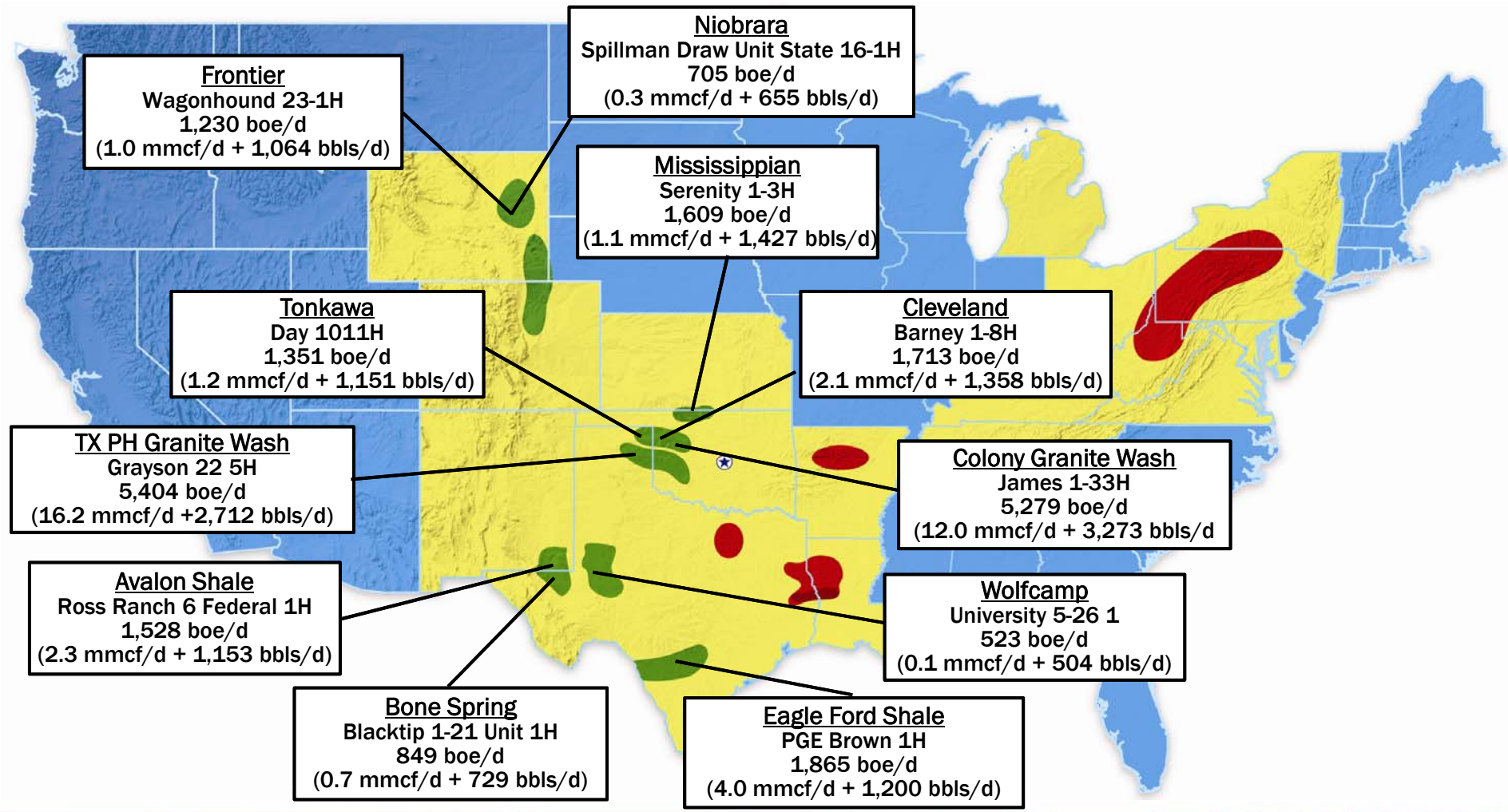
- **Instruments to measure mechanical properties:**
  - Fracture orientation
  - Vertical and horizontal compressional and shear sonic velocity
  - Hardness/toughness
  - Unconfined compressive strength

- **QA Proppant testing for optimized fracture design**
- **Simulating fractures in the lab**
- **CST - Rock sensitivity to frac fluids**
- **Propped fracture permeability stress dependence**



Fractured Core Measurements

Promising Starts in CHK's Liquid Plays

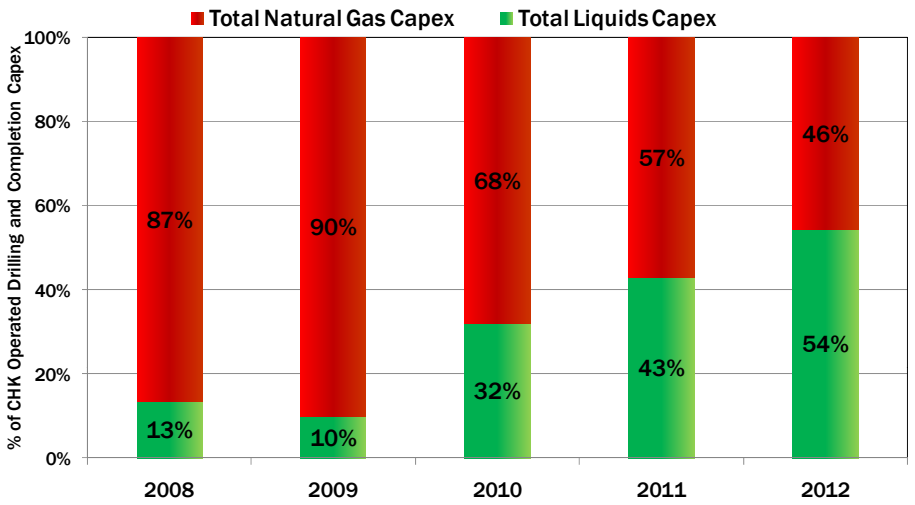


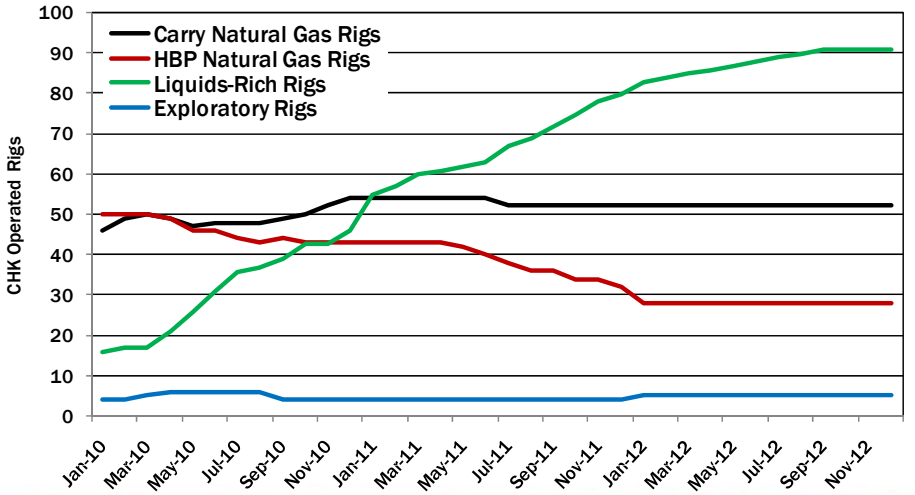
CHK is drilling big oil and liquid-rich wells in multiple developing plays

CHK Upstream Portfolio

Aggressively Shifting Capital to Liquids-Rich Plays

- Reducing drilling of natural gas wells except for those required to HBP leasehold or to use a drilling carry provided by a JV partner until natural gas prices rise above $6.00 per mcf
- Leasing and developing substantial new liquids-rich plays in which the company can acquire large leasehold positions of 250,000 - 1 million net acres
- Within one year of acquisition, CHK's strategy is to sell a minority interest in new plays to recover all or virtually all of the cost to acquire leasehold and fund a significant portion of CHK's future drilling costs in the plays
- Accelerate drilling of liquids-rich plays until YE'12 when CHK's drilling capex is balanced ~50/50 between natural gas plays and liquids-rich plays
- Continue adding proved reserves, net of monetizations and divestitures, of 2.5 - 3.5 tcfe (415 - 585 mmboe) annually

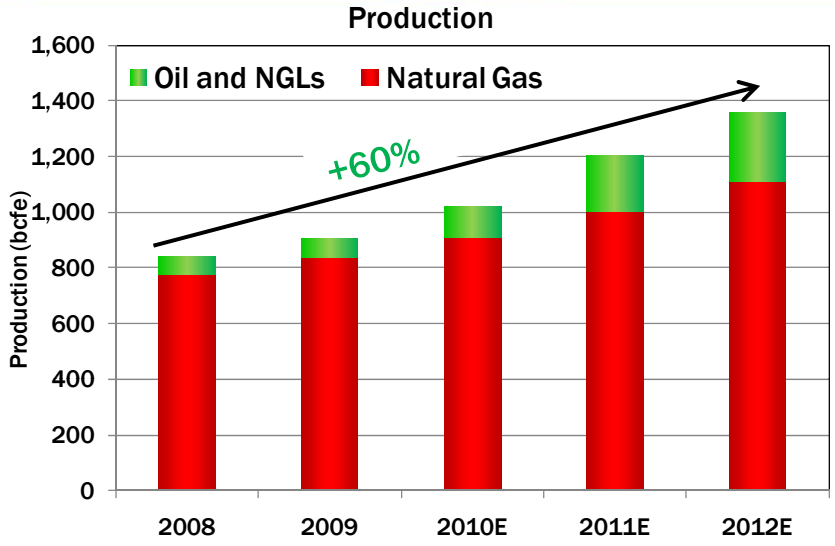


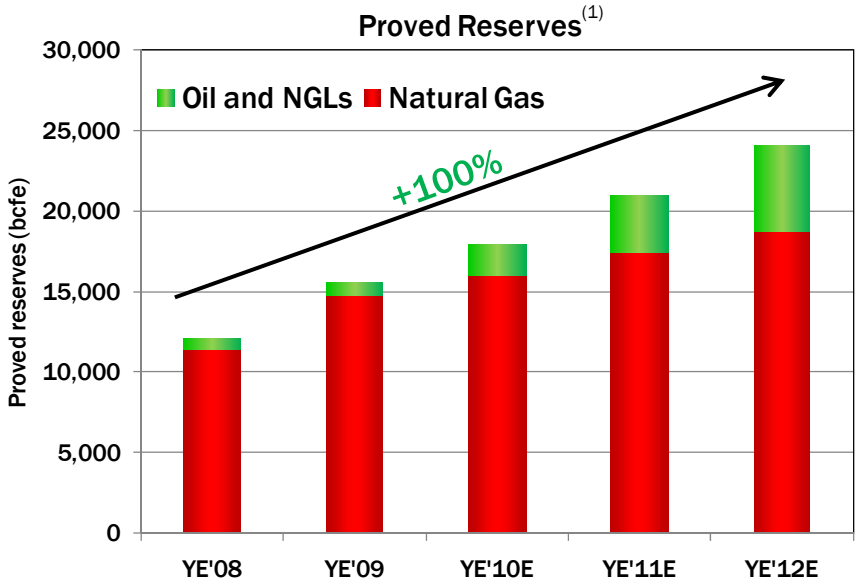


CHK will fund shift to liquids-rich plays by decreasing gas drilling and utilizing drilling carries from new JV partners

Strong Production Growth and Significant Additions from Liquids

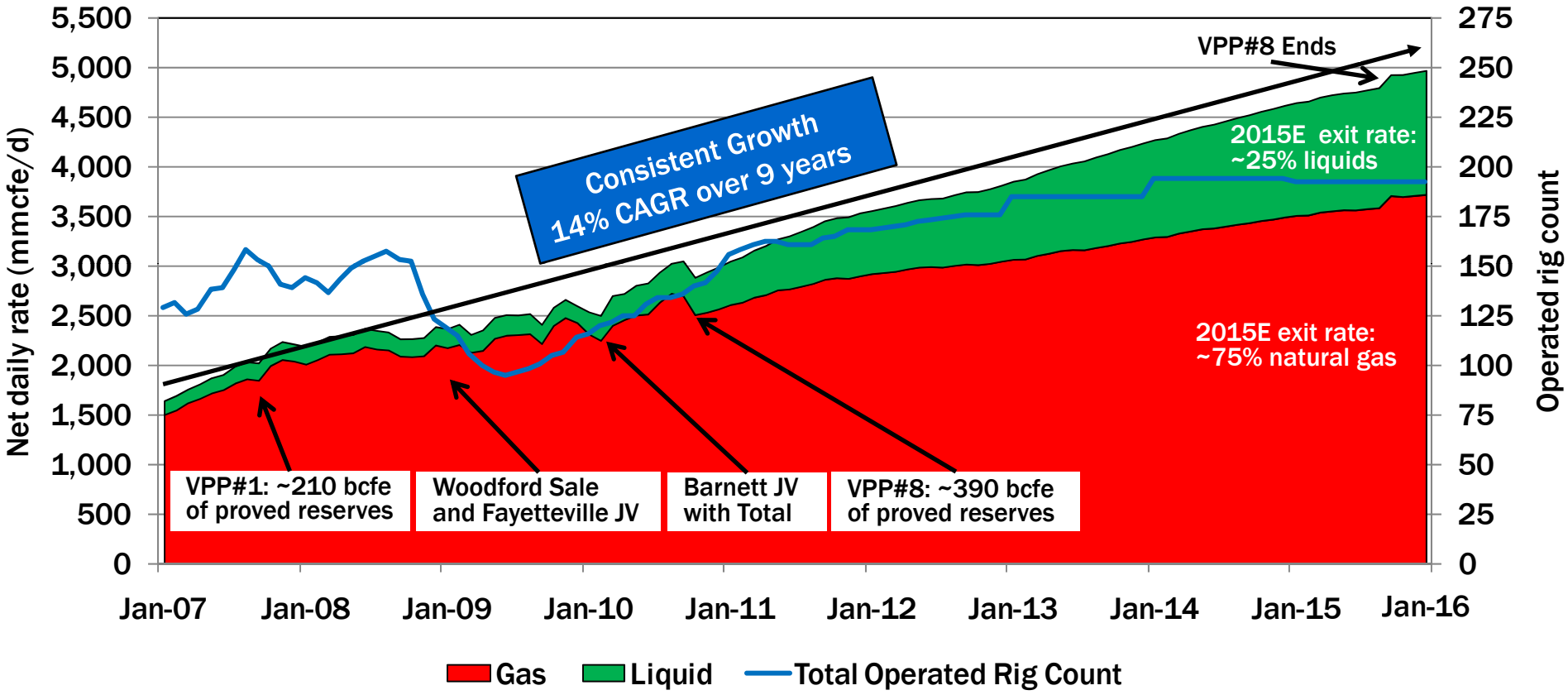
- From 2008 to 2012, CHK projects to increase total oil and natural gas production by ~60%
  - Liquids production projected to increase by ~265%
  - Natural gas production projected to increase by ~45%
- CHK to increase liquids production to ~100,000 bbls/d by YE'12
  - ~200,000 bbls/d by YE '15
- During the same period, CHK projects to increase total oil and natural gas reserves by ~100%
  - Liquids reserves projected to increase by ~630%
  - Natural gas reserves projected to increase by ~65%





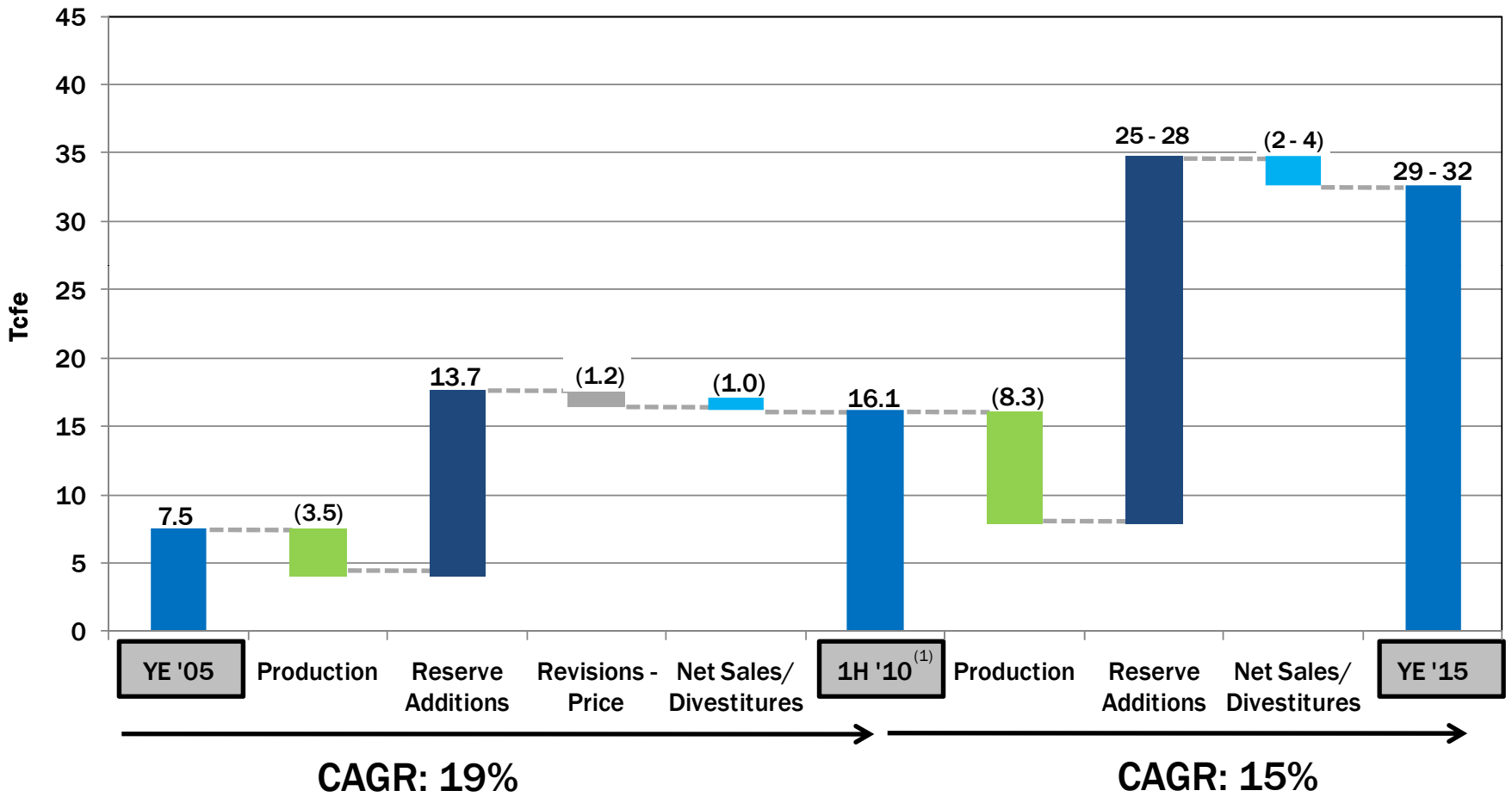
1) Based on 10-Year average NYMEX strip prices

CHK Long-term Production Outlook(1)



1) Includes completed and anticipated divestitures of producing properties

CHK Reserve Growth Will Be Unrivaled Over the Next Five Years



CHK reserves projected to grow ~14 tcfe from 1H '10 to YE '15, net of 8.3 tcfe of expected production and 2-4 tcfe of net sales/divestitures

1) Based on 10-Year average NYMEX strip prices at June 30, 2010; 15.5 tcfe of proved reserves using SEC pricing

Industry Leading Drilling Inventory

Play Type/Area	CHK Industry Position	CHK Net Acreage[1]	Est. Drilling Density (Acres)	Risk Factor	Royalty	Risked Net Undrilled Wells[1]	Unrisked Net Undrilled Wells[1]	Total Proved Reserves (bcfe)[1][2]	Risked Unproved Resources (bcfe)[1]	Total Proved Reserves and Risked Unproved Resources (bcfe)[1]	Unrisked Unproved Resources (bcfe)[1]	Sep-10 Average Production (mmcfe)	Oct-10 Operated Rig Count
Natural Gas Shale Plays:													
Marcellus Shale	#1	1,550,000	80	60%	15%	7,770	19,400	462	34,400	34,862	86,500	145	27
Haynesville Shale	#1	530,000	80	30%	25%	4,500	6,400	2,912	19,700	22,612	29,100	725	34
Barnett Shale	#2	220,000	60	15%	25%	1,840	2,400	2,895	3,400	6,295	4,400	555	21
Fayetteville Shale	#2	465,000	80	20%	17%	4,220	5,300	2,404	7,700	10,104	10,000	390	8
Bossier Shale[3]	#1	195,000	80	60%	25%	970	2,400	4	4,000	4,004	10,000	ND	1
Subtotal		2,765,000	Various			19,300	35,900	8,677	69,200	77,877	140,000	1,815	91
Unconventional Liquids Plays:													
Anadarko Basin[4]	#1	930,000	140	60%	20%	2,500	6,100	1,824	9,100	10,924	20,930	420	23
Eagle Ford Shale	#1	625,000	80	ND	25%	ND	7,800	25	ND	ND	20,900	ND	10
Permian Basin[5]	Top 5	615,000	90	ND	23%	ND	4,500	177	ND	ND	10,200	ND	7
Rocky Mountain[6]	Top 5	685,000	160	ND	20%	ND	5,500	25	ND	ND	13,800	ND	4
Subtotal		2,855,000	Various			8,150	23,900	2,051	22,100	24,151	65,830	490	44
Other Conventional and Unconventional Plays	Top 3	8,320,000	Various	Various	Various	13,750	53,700	5,418	8,000	13,418	34,700	750	5
Total		13,940,000				41,200	113,500	16,146	99,300	115,446	240,530	3,050	140

- ND denotes "not disclosed"
- Risk disclosure regarding unproved resource estimates appears on page iii

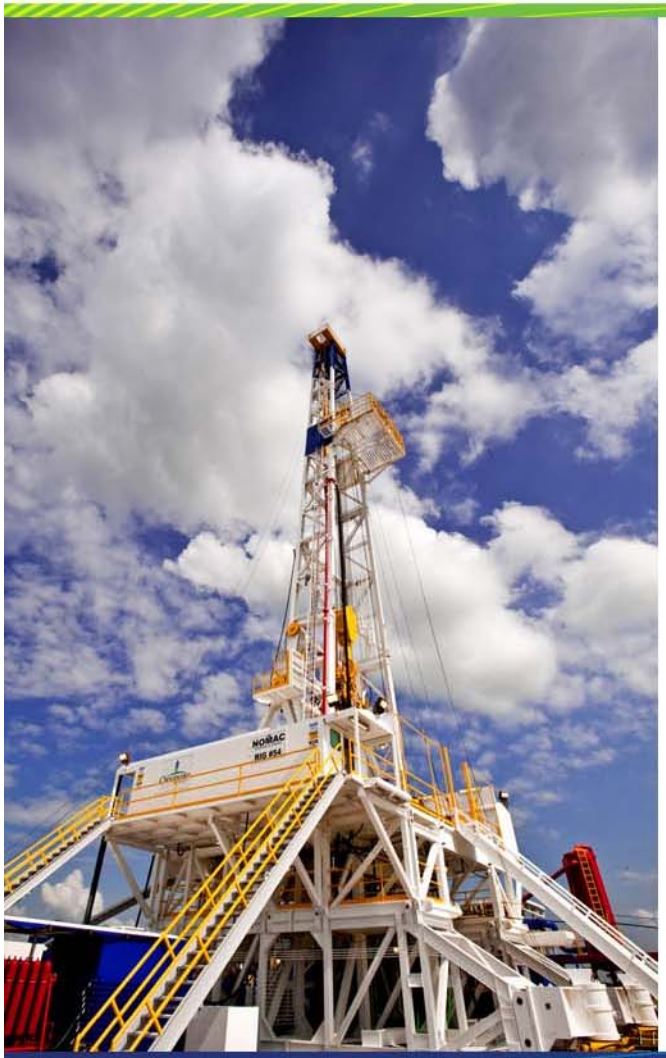
1) As of June 30, 2010, pro forma for Eagle Ford and Rockies recent transactions; excludes pro forma adjustments for recently announced Eagle Ford JV
2) Based on 10-Year average NYMEX strip prices at June 30, 2010; 15.5 tcfe of proved reserves using SEC pricing
3) Bossier shale acreage overlaps with Haynesville Shale acreage and is excluded from the shale play subtotal to avoid double counting of acreage
4) Includes Colony, Texas Panhandle and other Granite Washes, Cleveland, Tonkawa and Mississippian plays
5) Includes only Avalon Shale, Bone Spring, Wolfcamp and Spraberry plays
6) Includes only Niobrara and Frontier plays

Natural Gas Shale Plays

Marcellus, Haynesville, Bossier, Barnett and Fayetteville

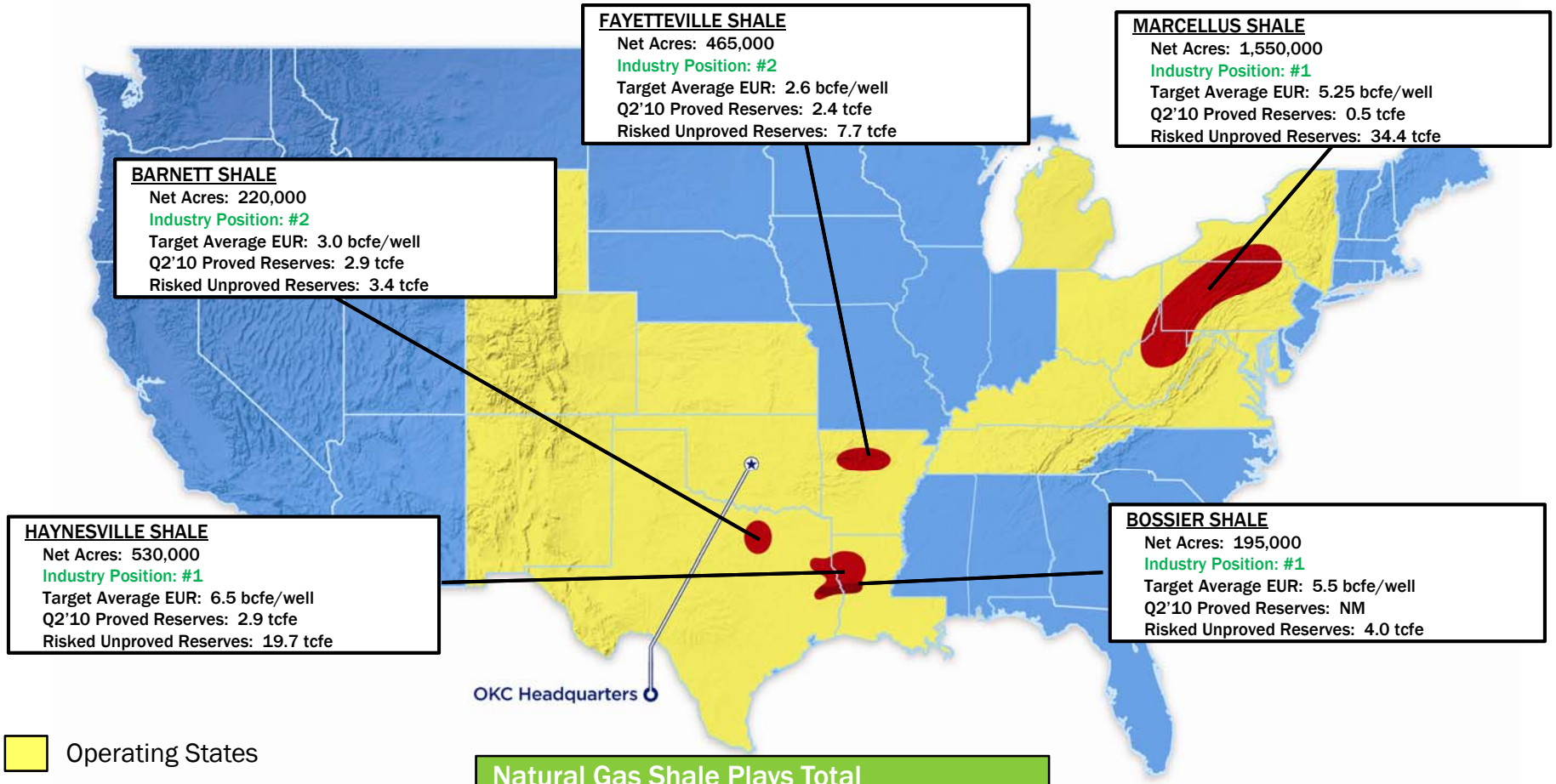
John Sharp, Vice President - Geoscience, Southern Division

CHK is the Leader of U.S. Natural Gas Shale Development



- **CHK is either the first or second-largest producer and leasehold owner in the five largest U.S. natural gas shale plays: Marcellus, Haynesville, Bossier, Barnett and Fayetteville**
- **CHK has a tremendous information advantage, understands the science and targets the best rocks in a play – CHK is not a fringe acreage player**
  - Data, technology and comprehensive reservoir analysis is key to success
- **Unparalleled track-record of execution in large resource plays**
  - Pace and efficiency matter
  - Demonstrated cost control
  - Broad based experience and knowledge transfer across multiple plays
- **CHK is the established JV partner of choice**
  - Five successful large JV's (BP, PXP, STO, TOT, CEO)
    - Others on the way
  - Collaboration with partners brings new ideas and technology as well as even greater accountability
- **Committed to environmental, health and safety (EHS)**
  - It's good business and it's mandatory at CHK
  - Leader in industry with scale and expertise

CHK's #1 Natural Gas Shale Position

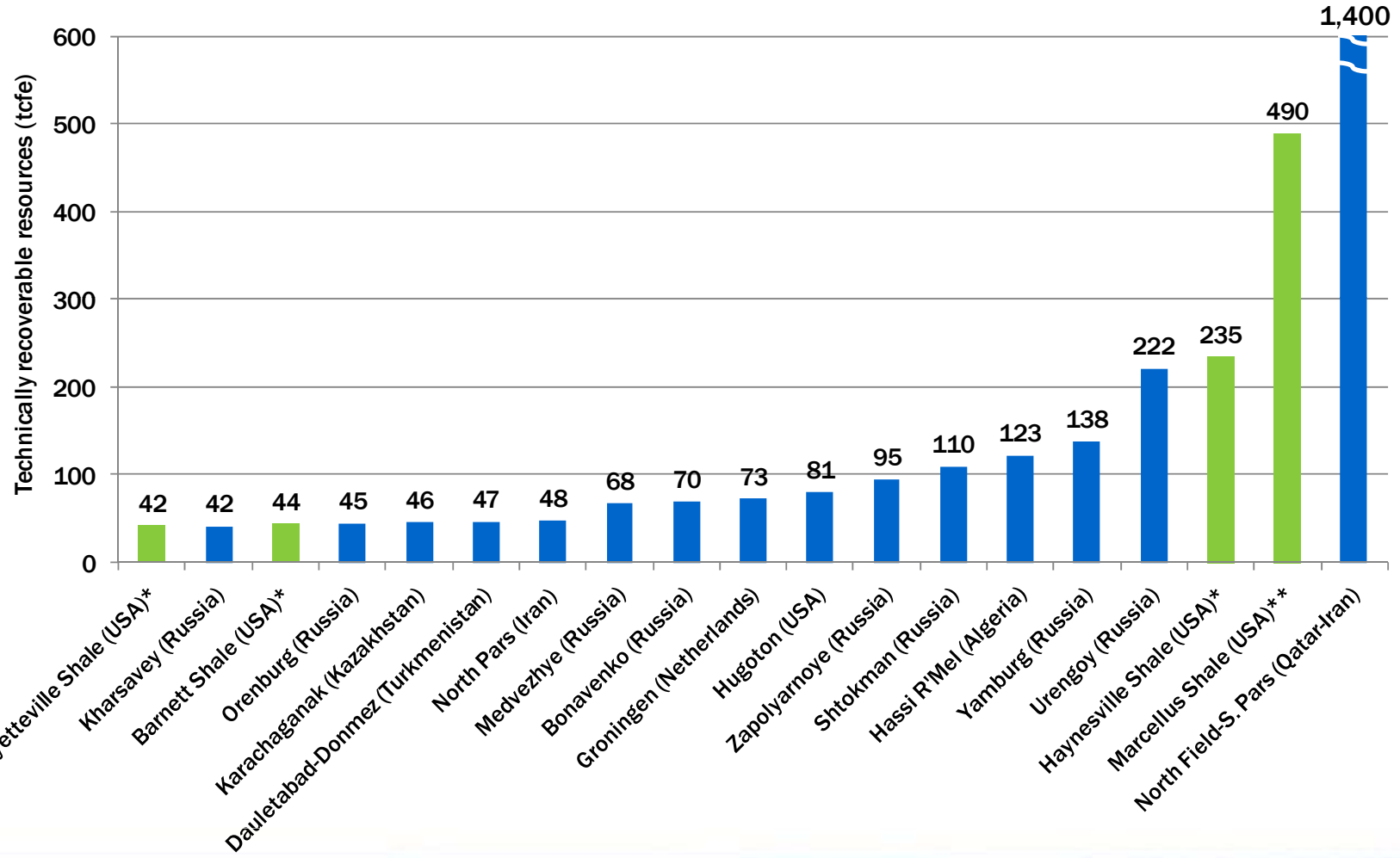


Natural Gas Shale Plays Total
- Net Acres(1): 2,765,000
- Industry Position: #1
- Q2'10 Proved Reserves: 8.7 tcfe
- Risked Unproved Reserves: 69 tcfe

Data above:
- As of June 30, 2010, as adjusted to reflect current targeted well results
- Based on 10-yr average NYMEX strip prices at June 30, 2010

1) Bossier Shale acreage overlaps with Haynesville Shale acreage and is excluded from the shale play subtotal to avoid double counting of acreage

U.S. Natural Gas Shale Plays are World-Class Resources

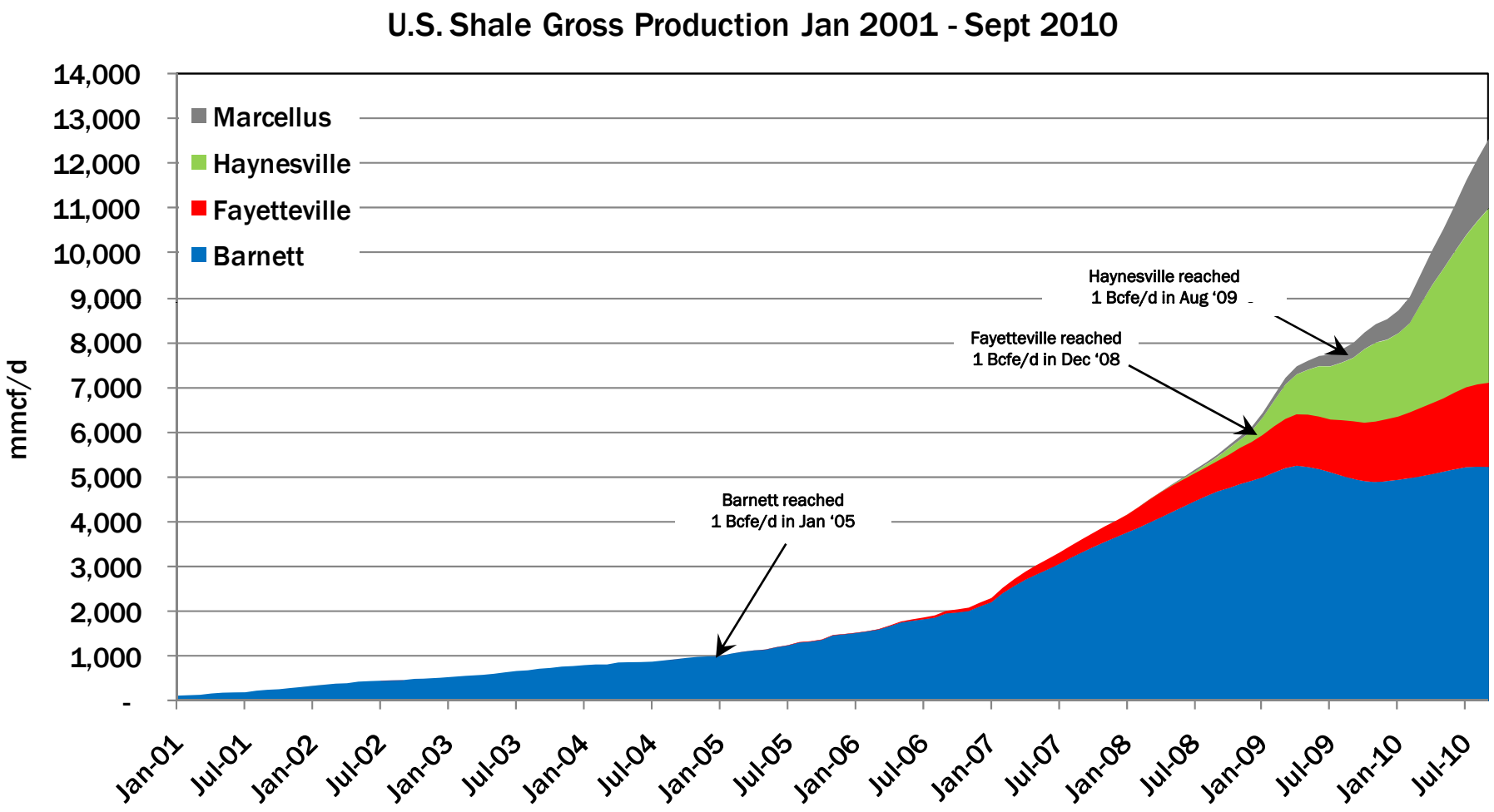


*U.S. Department of Energy (April 2009): Modern Shale Gas Development in the United States: A Primer, p. 17
**Dr. Terry Engelder, Penn State University

General Trends in Natural Gas Shale Plays

- Once a core area has been established, production and reserves are very low-risk and highly predictable
- Defining key reservoir characteristics enables core areas to be more quickly delineated
- Large difference in the returns from core acreage versus fringe acreage
- More mature plays demonstrate strong EUR vs. lateral length relationship
- More mature plays reveal improvement in EUR over time due to optimization of completion designs and methods
- Economics improve through reduced cycle times and leverage of existing infrastructure
- Once acreage is HBP, producers gain greater discretion on drilling timing
  - Time drilling for more favorable gas prices
  - Capitalize on greater efficiencies from pad drilling and midstream optimization
  - True gas manufacturing
- Key infrastructure additions have significantly added to take away capacities

U.S. Natural Gas Shale Development



CHK's gross operated shale gas production of ~3.0 bcf/d is ~23% of total U.S. shale gas production!

Major Natural Gas Shale Typical Characteristics

	Marcellus	Haynesville	Bossier	Barnett	Fayetteville
GIP unrisked (tcf)	1,900	670	280	355	105
Unrisked recovery @ 35% (tcf)	665	235	100	125	35
Depth TVD	6,200'	11,900'	11,650'	7,300'	5,700'
Thickness (net)	150'	260'	245'	350'	135'
Thermal maturity (vitrinite reflectance)	1.8%	2.7%	2.7%	2.4%	2.4%
Average log porosity	6.2%	8.3%	7.5%	5.1%	5.9%
Pressure (psi/foot)	0.61	0.84	0.78	0.46	0.42
Gas-in-place (bcfe/section)	130	190	165	65	55
Anticipated recovery factor	30%	28%	28%	40%	38%
Avg. EUR/horizontal well (bcfe)	5.25	6.5	5.5	3.0	2.6
CHK horizontal rigs	27	34	1	21	8
Industry horizontal rigs	84	139	13	66	21
Total horizontal activity	111	173	14	87	29
CHK % of industry total	24%	20%	7%	24%	28%
Key competitors	RRC, APC COG, TLM	ECA, HK, XCO	ECA, HK, XCO	DVN, EOG, XOM	SWN, XOM

Industry Big 5 horizontal activity (414) = 26% of current land rig utilization (1,564)[1].
CHK (91 horizontal rigs) is responsible for 22% of current total activity within the Big 5 Shale Plays and is #1 driller in all.

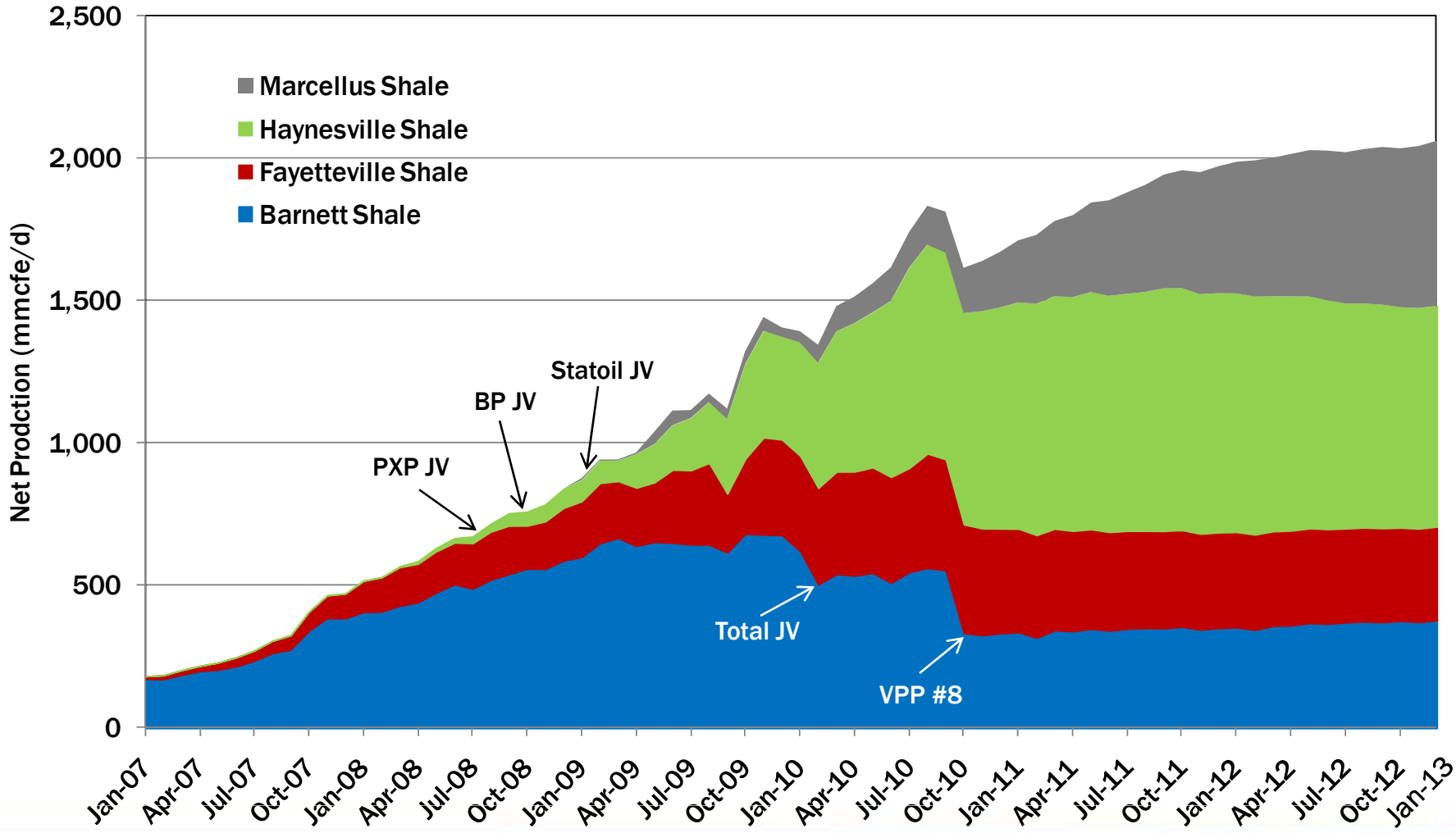
1) Smith Bits report dated 10/1/10

CHK's Tremendous Natural Gas Shale Resource Base

Gas Shale Basin	Marcellus	Haynesville	Bossier [1]	Barnett	Fayetteville	Total
Net acres[2]	1,550,000	530,000	195,000	220,000	465,000	2,765,000
Estimated drilling density (acres)	80	80	80	60	80	Various
Risk factor	60%	30%	60%	15%	20%	Various
Risked net undrilled wells	7,770	4,500	970	1,840	4,220	19,300
Estimated avg. reserves per well (bcfe)	5.25	6.5	5.5	3.0	2.6	Various
Total proved reserves (tcfe)[2][3]	0.5	2.9	0	2.9	2.4	8.7
Risked unproved resources (tcfe)[2][3]	34.4	19.7	4.0	3.4	7.7	69.2
Unrisked unproved resources (tcfe)[2][3]	86.5	29.1	10.0	4.4	10.0	140.0
September '10 avg. daily net production (mmcfe)	145	725	ND	555	390	1,815
Current operated rig count	27	34	1	21	8	91
YE 2011E operated rig count	34	22	2	18	8	84
Targeted avg. IP rate	4.1	14.1	11.0	3.1	2.3	
Budgeted drilling and completion costs ($ in millions)	$5.0	$7.8	$7.8	$2.8	$3.2	
Days to drill (spud to spud)	30	46	46	16	18	

1) Bossier Shale acreage overlaps with Haynesville Shale acreage and is excluded from the shale total to avoid double counting of acreage
2) As of June 30, 2010, excluding risked unproved reserves which are based on updated type curves as of 10/13/10.
3) Based on 10-yr average NYMEX strip prices at June 30, 2010

CHK Natural Gas Shale Production Profile

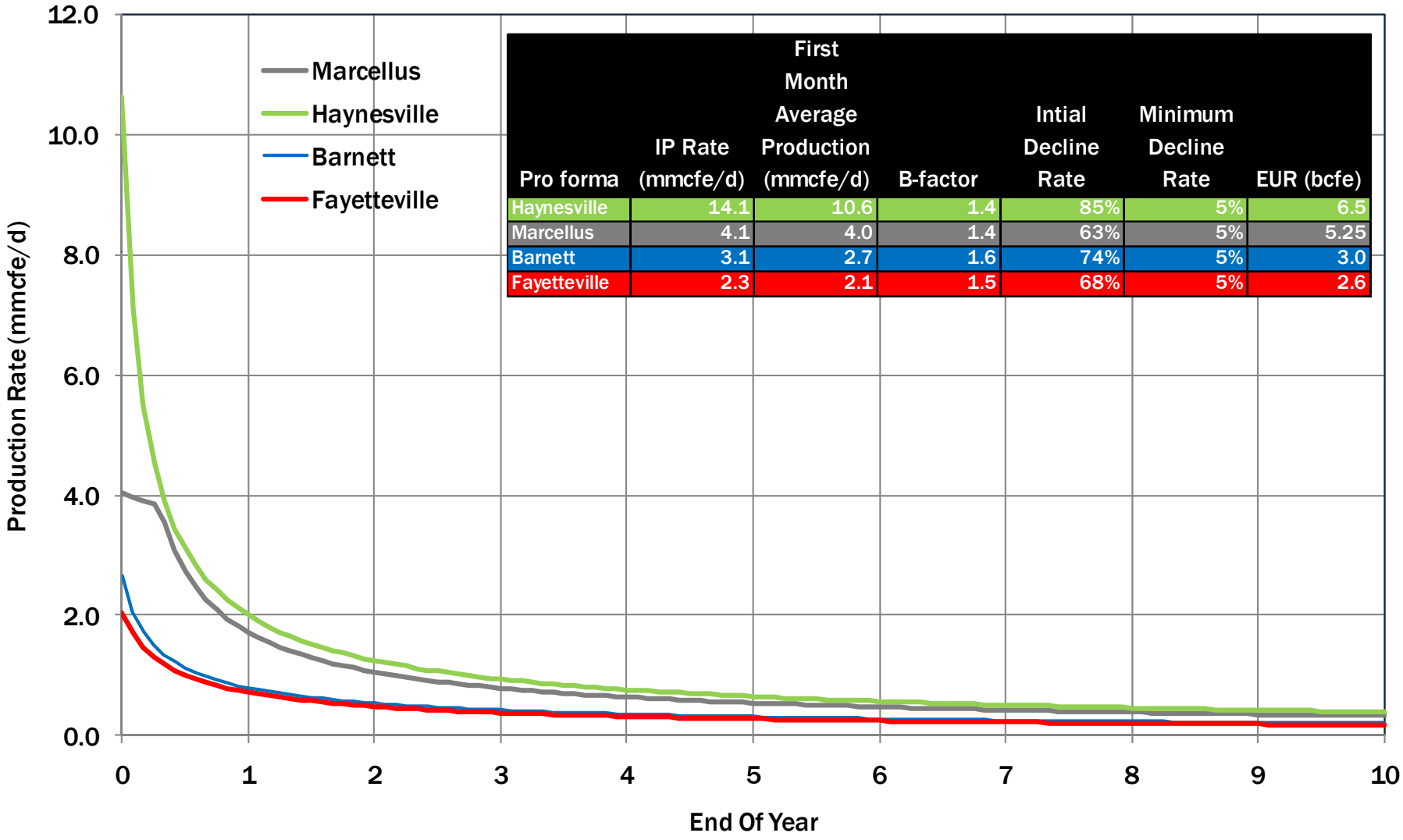


CHK is the industry leader in natural gas shale development

Efficiency – Focused on Improvements

- **Continual focus on process**
  - Superior rig fleet and personnel through Nomac (98 rigs)
  - Superior science with in-house rock laboratory (CRTC)
  - Reduced rig mobilization time by scheduling more efficient moves
  - Reduced trouble time through improved well design
  - Reduced lateral drilling days by rotating out last portion of hole
  - Application of play-specific bit and motor designs to boost drilling efficiencies
  - Leveraged volume work for favorable vendor pricing in escalating market for services
  - Optimized completion and production methods by play and by field area
  - Improving quality of leasehold inventory – focus on core
- **How much better can we get?**
  - Reduce lateral drilling time through continued improvements in directional tools
  - Continued optimization of drilling parameters with experience and local knowledge
  - Fine tune completion designs and production methods for sub-field areas
  - Streamline development strategies to boost economics and cycle time
  - Tackling science with geo-modeling, reservoir simulation and seismic attributes

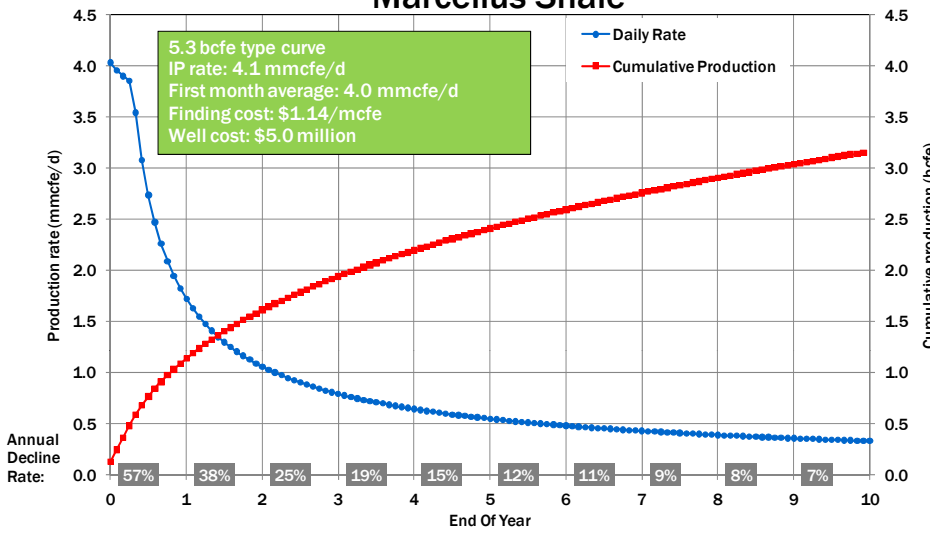
Natural Gas Shale Plays – Type Curves



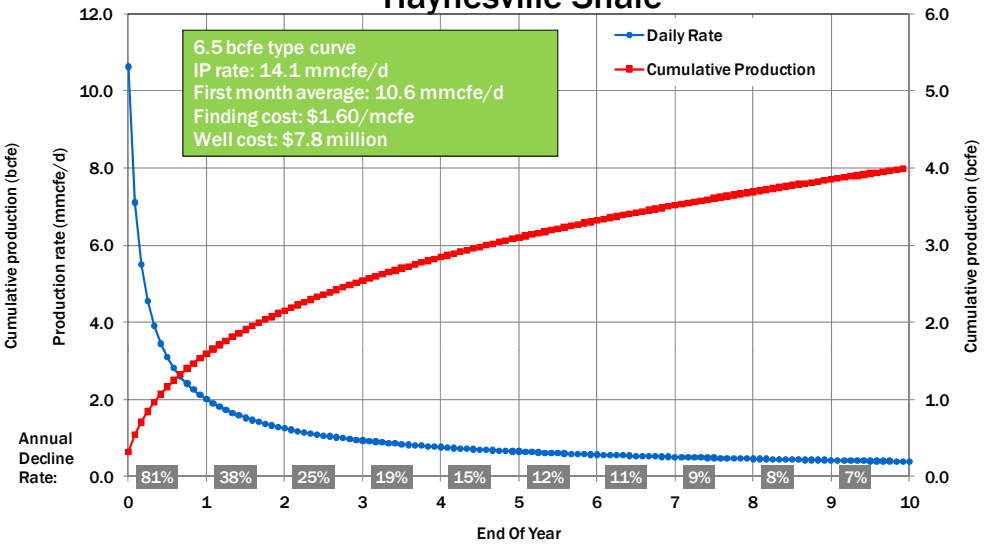
Pro forma	IP Rate (mmcfe/d)	First Month Average Production (mmcfe/d)	B-factor	Intial Decline Rate	Minimum Decline Rate	EUR (bcfe)
Haynesville	14.1	10.6	1.4	85%	5%	6.5
Marcellus	4.1	4.0	1.4	63%	5%	5.25
Barnett	3.1	2.7	1.6	74%	5%	3.0
Fayetteville	2.3	2.1	1.5	68%	5%	2.6

Natural Gas Shale Plays – Targeted Well Profiles

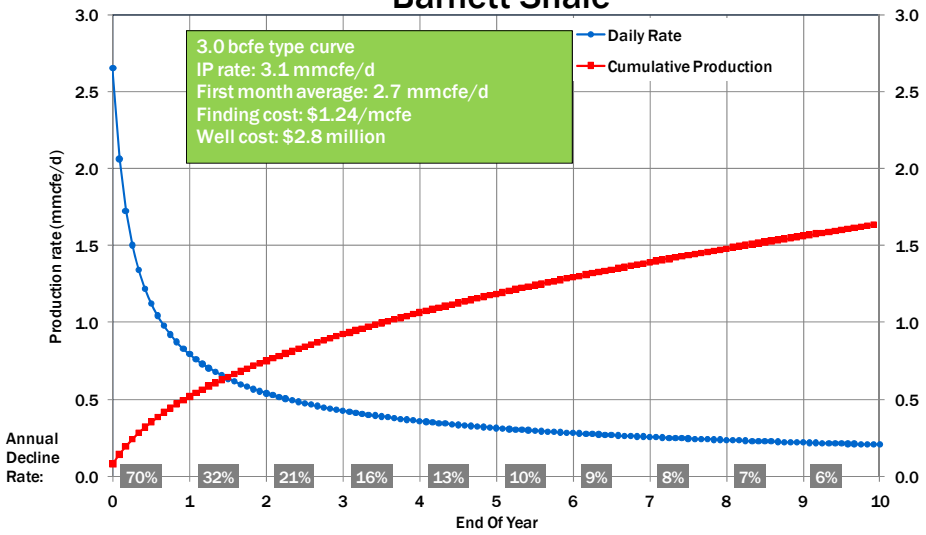
Marcellus Shale



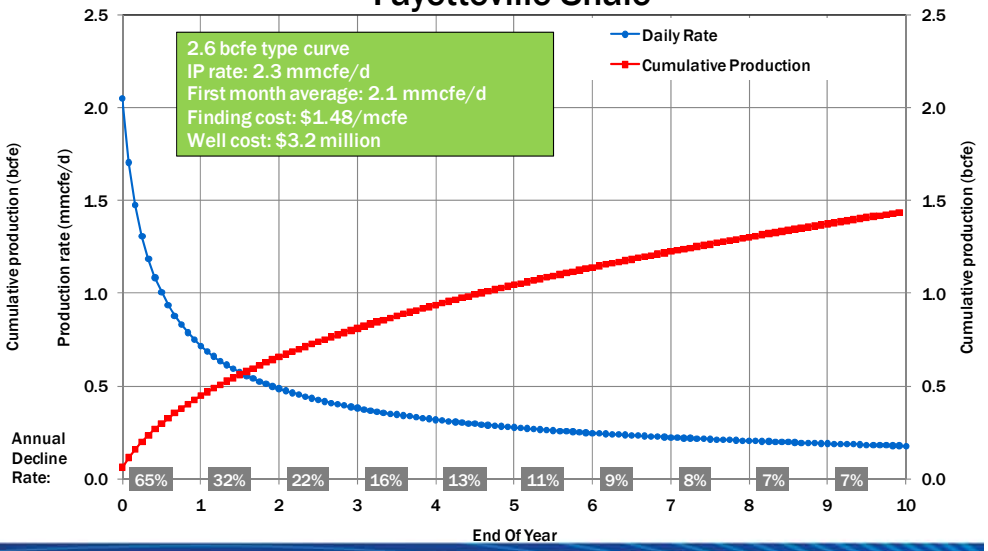
Haynesville Shale



Barnett Shale

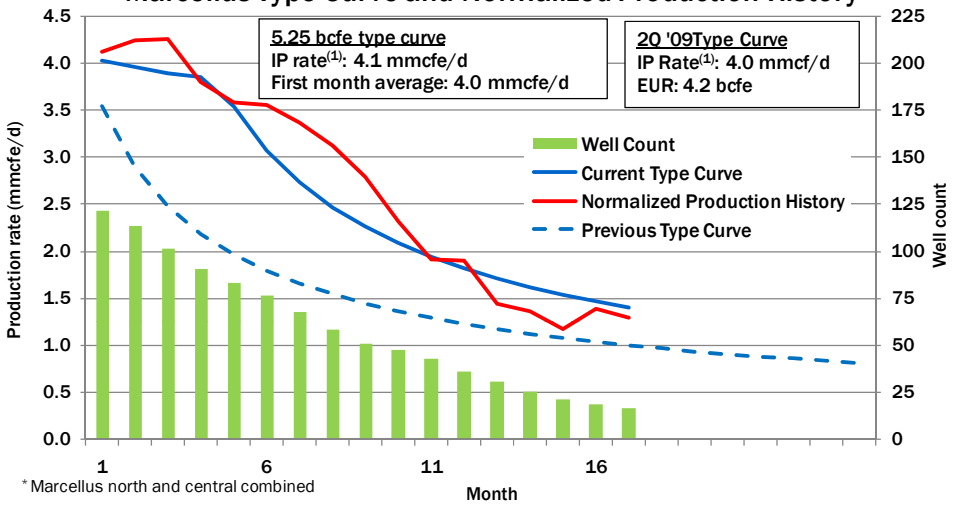


Fayetteville Shale



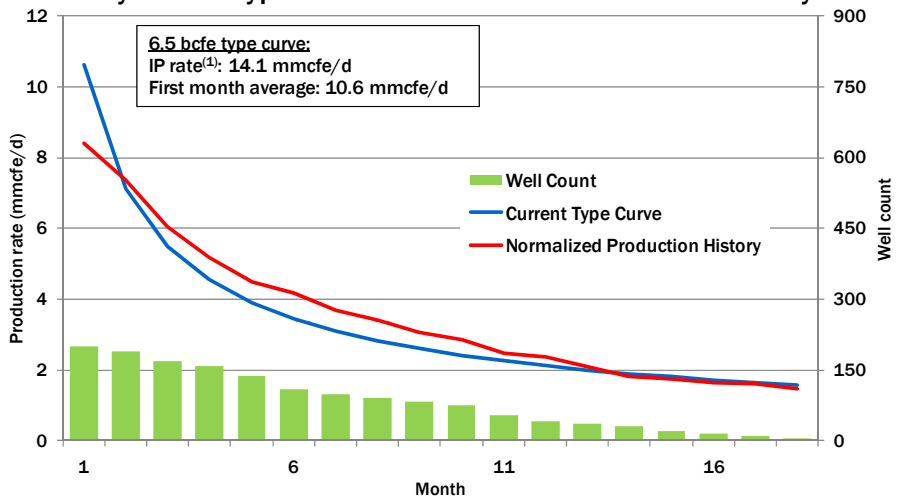
Natural Gas Shale Plays – Results to Date

Marcellus Type Curve and Normalized Production History*

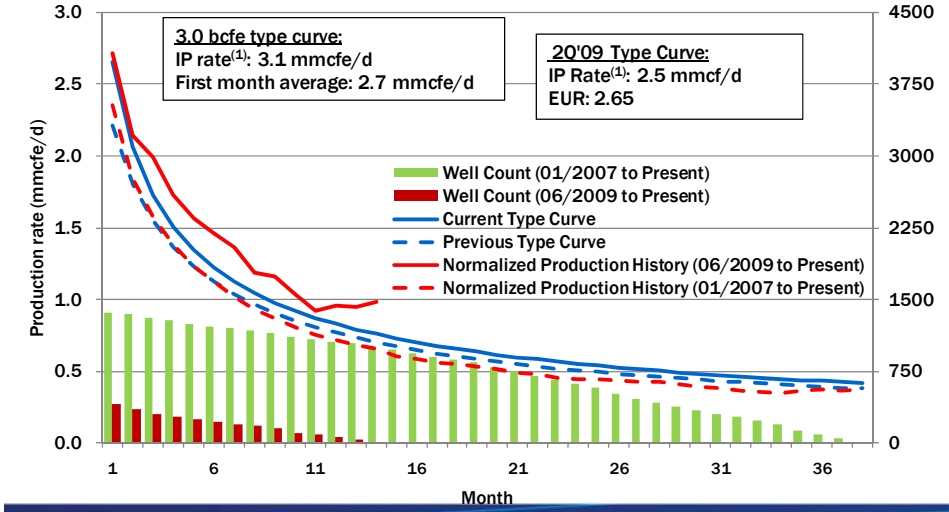


*Marcellus north and central combined

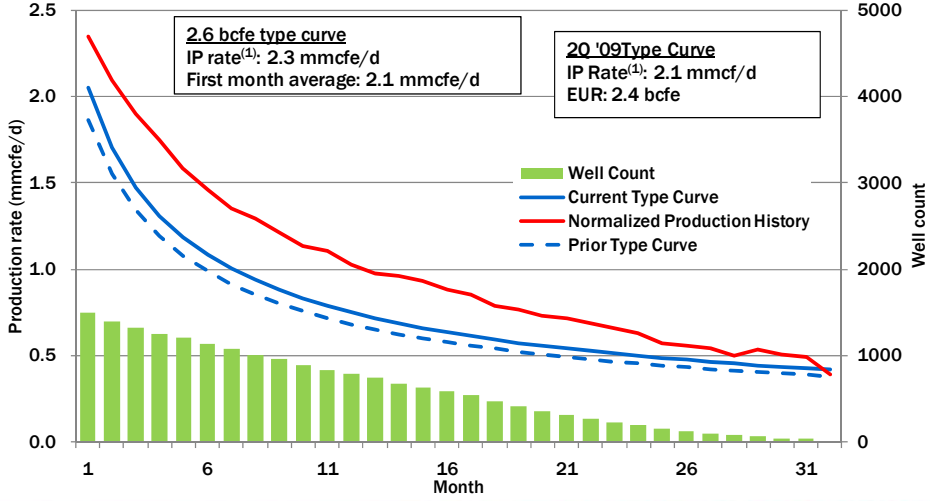
Haynesville Type Curve and Normalized Production History



Barnett Type Curve and Normalized Production History



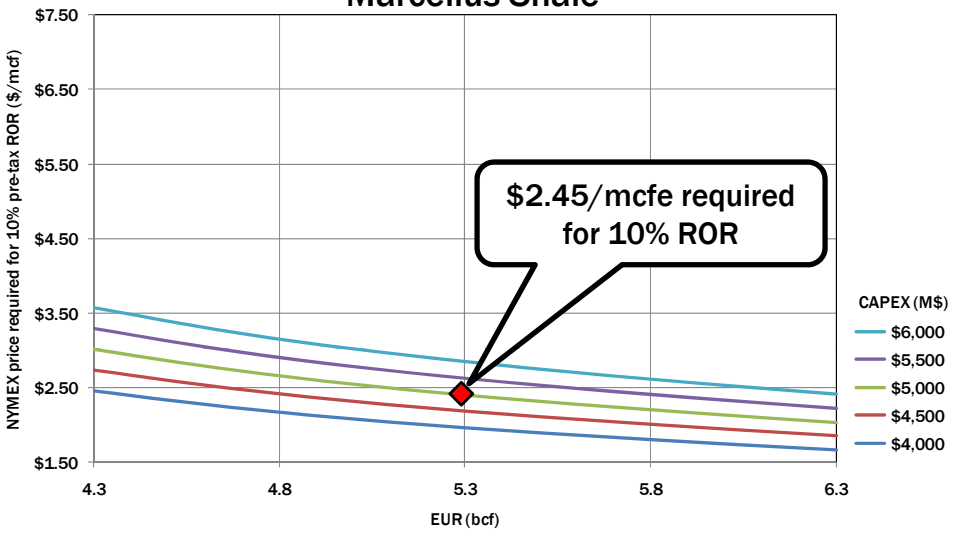
Fayetteville Type Curve and Normalized Production History



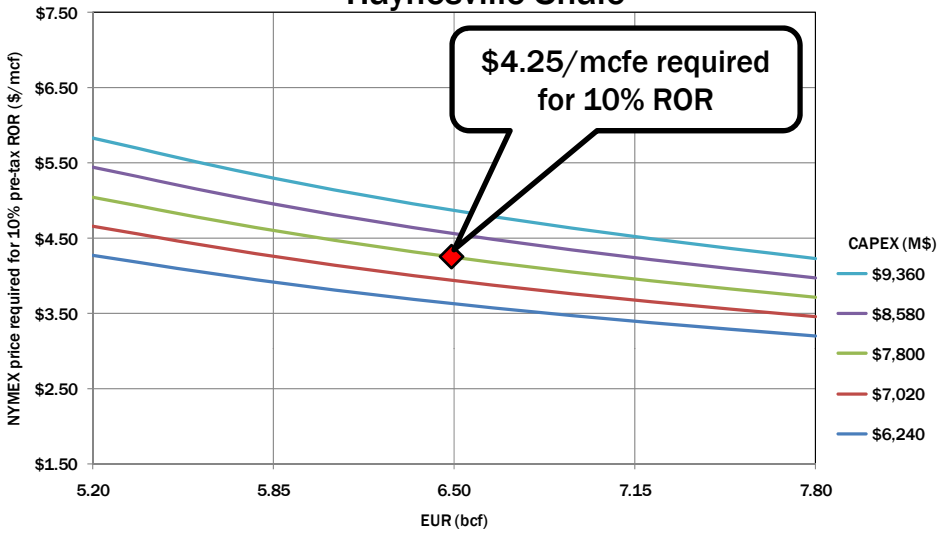
(1) Peak 24-hour rate

Natural Gas Shale Plays – PV10 Sensitivity

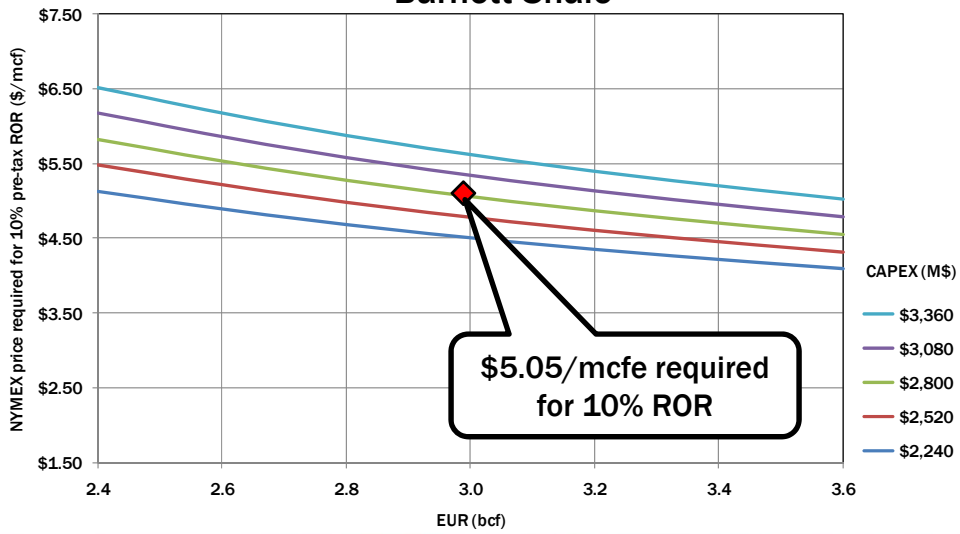
Marcellus Shale



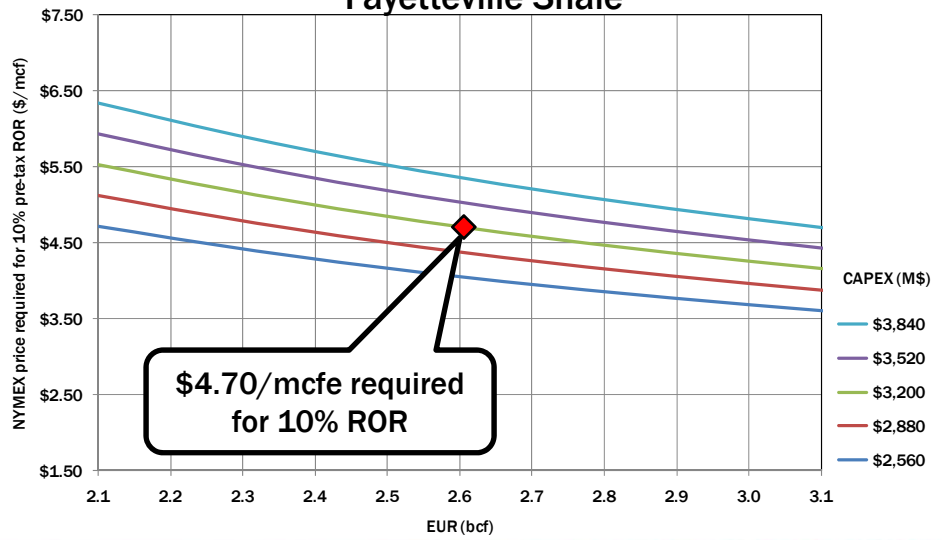
Haynesville Shale



Barnett Shale



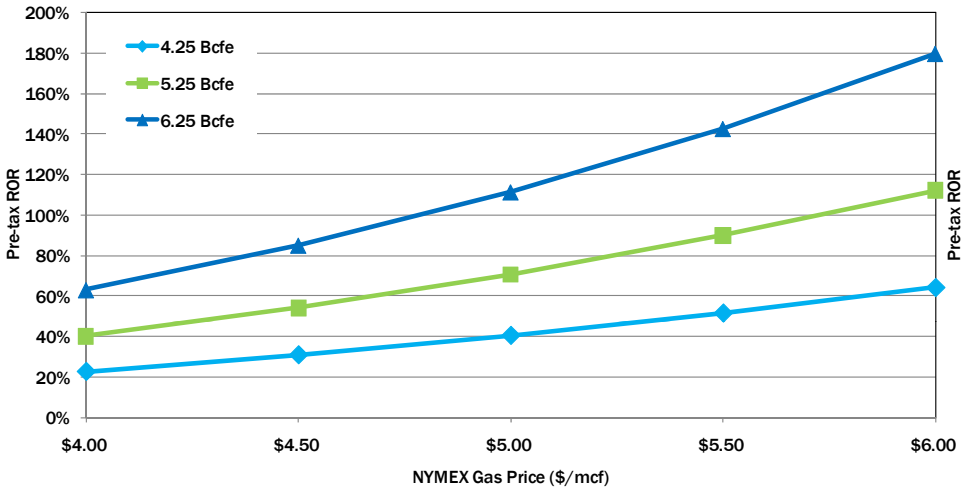
Fayetteville Shale



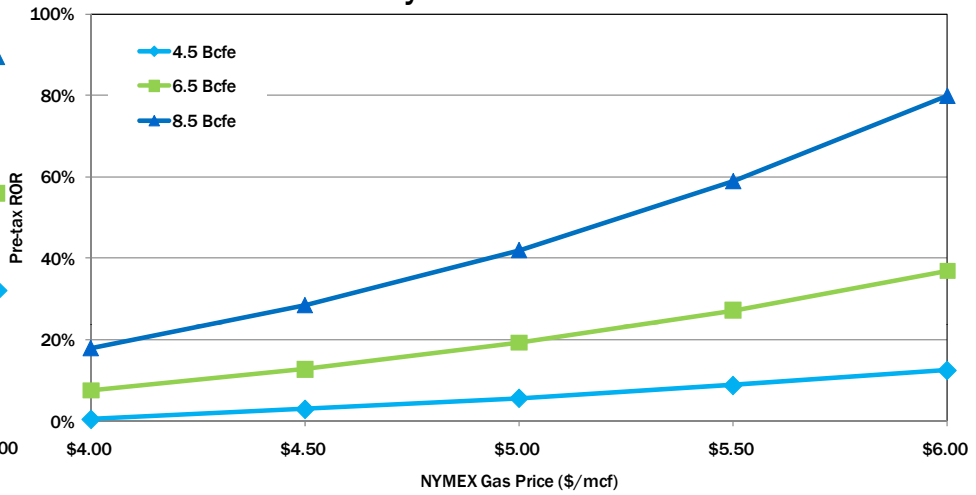
Type curve

Natural Gas Shale Plays – Rates of Return

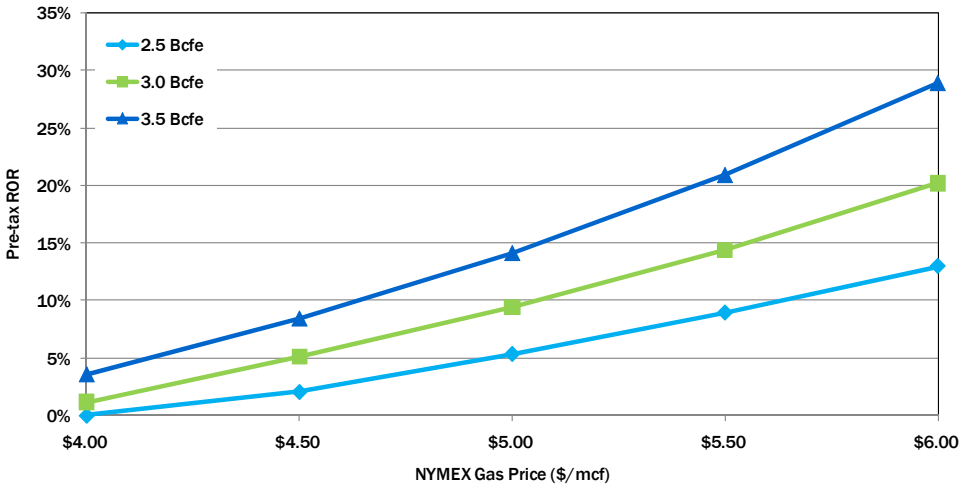
Marcellus Shale



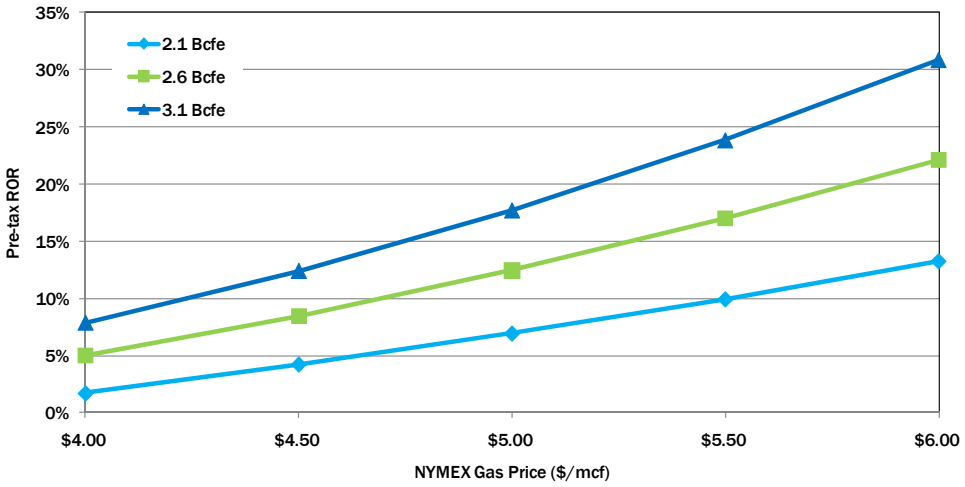
Haynesville Shale



Barnett Shale

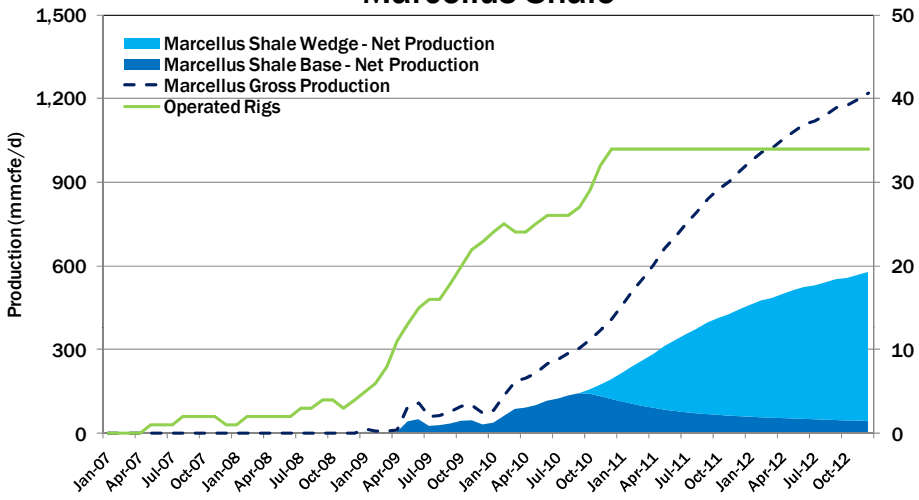


Fayetteville Shale

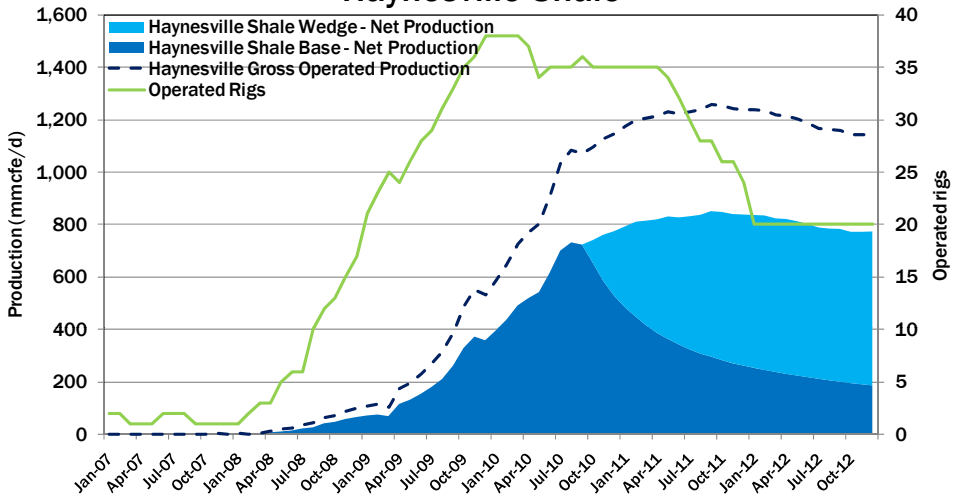


Natural Gas Shale Plays – Production Profile

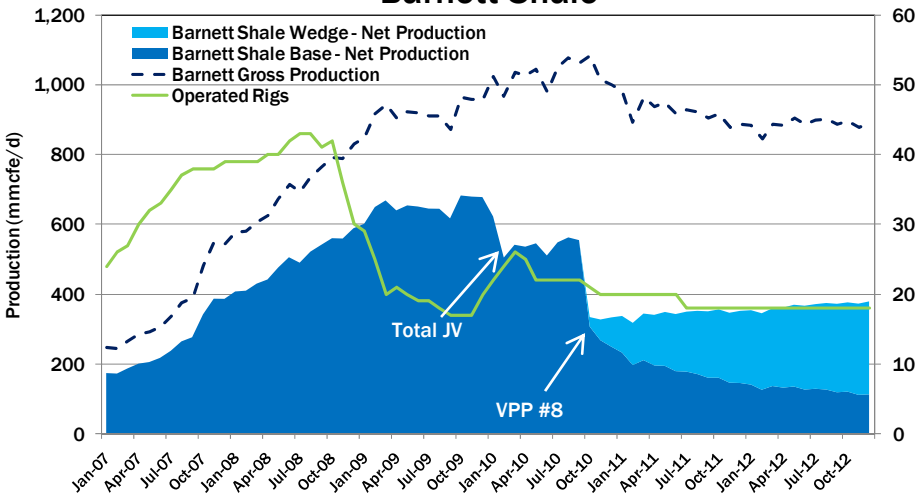
Marcellus Shale



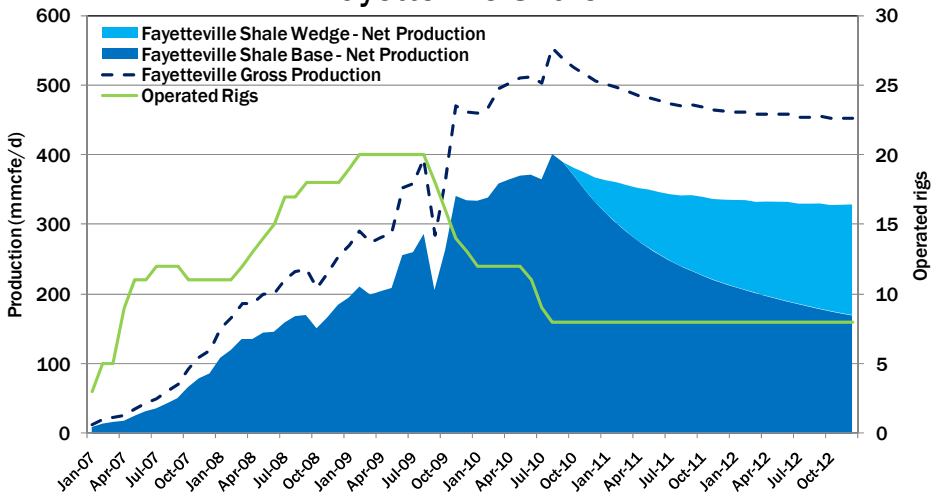
Haynesville Shale



Barnett Shale



Fayetteville Shale

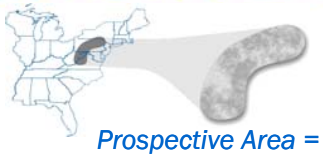


Natural Gas Shale Plays – CHK Advantages

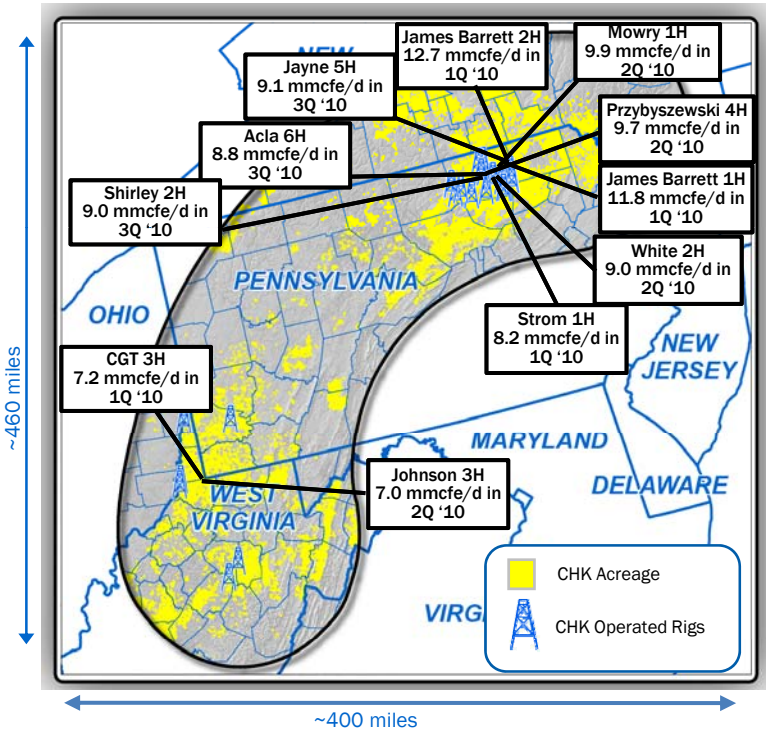
- **Technological experience**
  - Unconventional expertise drives creativity and efficiency
    - Technology transfers to and from other shale plays
    - CRTC provides quick turn around and quality control on log/core data
  - Log, core and 3D seismic database unmatched in the industry
- **Acreage acquisition**
  - First mover advantage
    - Dominant leasing activity in core areas
  - Partner advantage
    - Successful JV's bring capital and technical collaboration
- **Drilling and completion**
  - Most active driller in Big 5 shale plays
    - Over 3,600 wells drilled to date
  - Continued optimization of drilling and completion practices in each play
  - Superior rig fleet and personnel with Nomac
  - Leader in urban development
- **Regulatory**
  - A strong state and federal regulatory team
  - Commitment to excellence in environmental, health and safety

Marcellus Shale Highlights

Marcellus Shale – Overview



Prospective Area = ~15 Million Acres



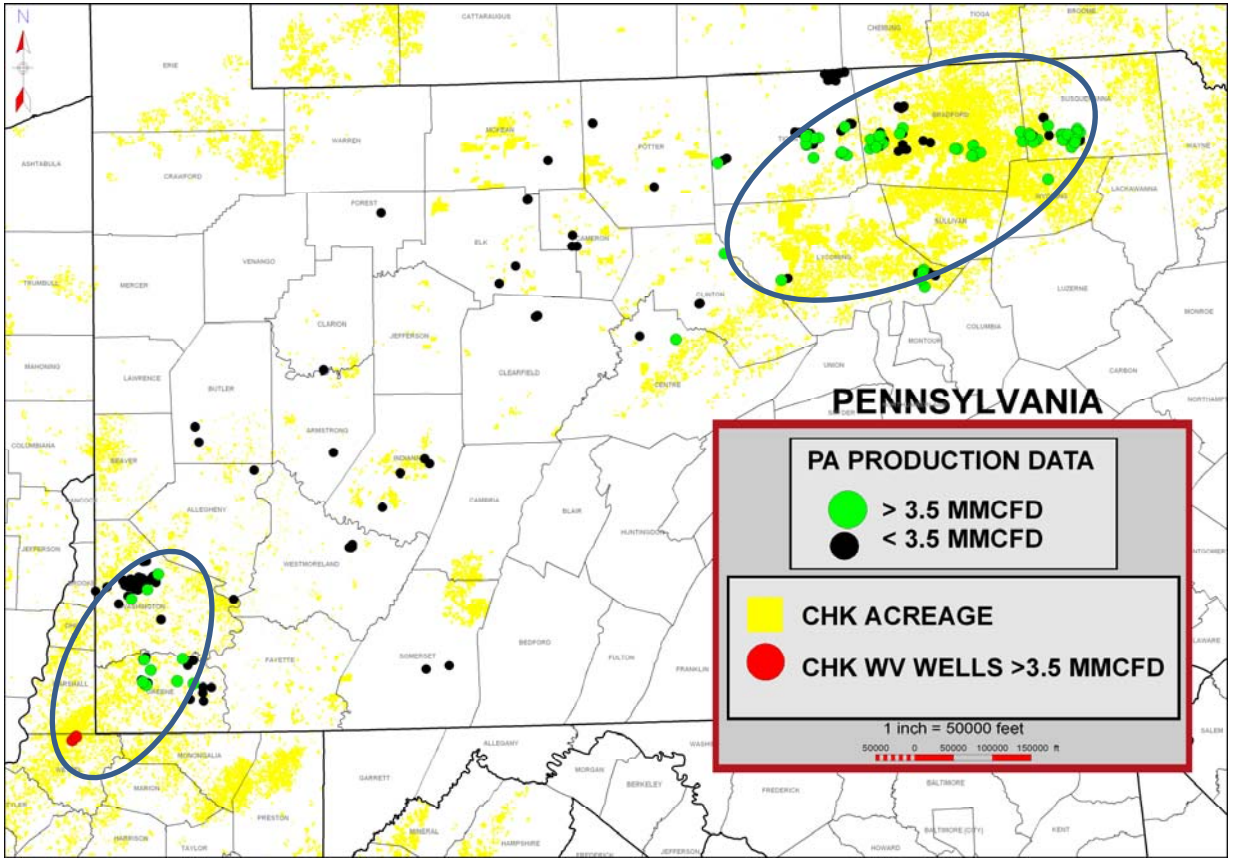
Note: Well results above are peak 24-hour rate

- The Marcellus Shale play is likely to become one of the two largest gas fields in the U.S. (Haynesville the other)
- CHK is the largest producer, the most active driller and the largest leasehold owner in the play with 1.55 mm net acres of leasehold
- 67.5/32.5 JV with Statoil (STO) in 11/08; $3.375 billion in cash and drilling carries
- CHK has 462 bcfe of proved reserves(1), ~34 tcfe of risked unproved resources(2) and ~87 tcfe of unrisked unproved resources(2)
- Current net production of 145 mmcfe/d(3), up ~300% YOY
- CHK has recently raised its targeted average EUR on its acreage by ~25% from 4.2 bcfe per well to 5.25 bcfe per well because of outstanding well performance
- Currently operating 27 rigs in the play; plan to average ~34 rigs in '11 to drill ~190 net wells
  - From July 2010 - 12, CHK should receive ~$1.7 billion in additional drilling carries from STO
- CHK has ~ 75 net producing Marcellus wells; 19,400 net unrisked wells left to drill

1) Based on 10-yr average NYMEX strip prices at June 30, 2010
2) Risk disclosure regarding unproved resource estimates appears on page iii of the meeting presentation package
3) September 2010 average

Marcellus Sweet Spots – Core Areas Starting To Emerge

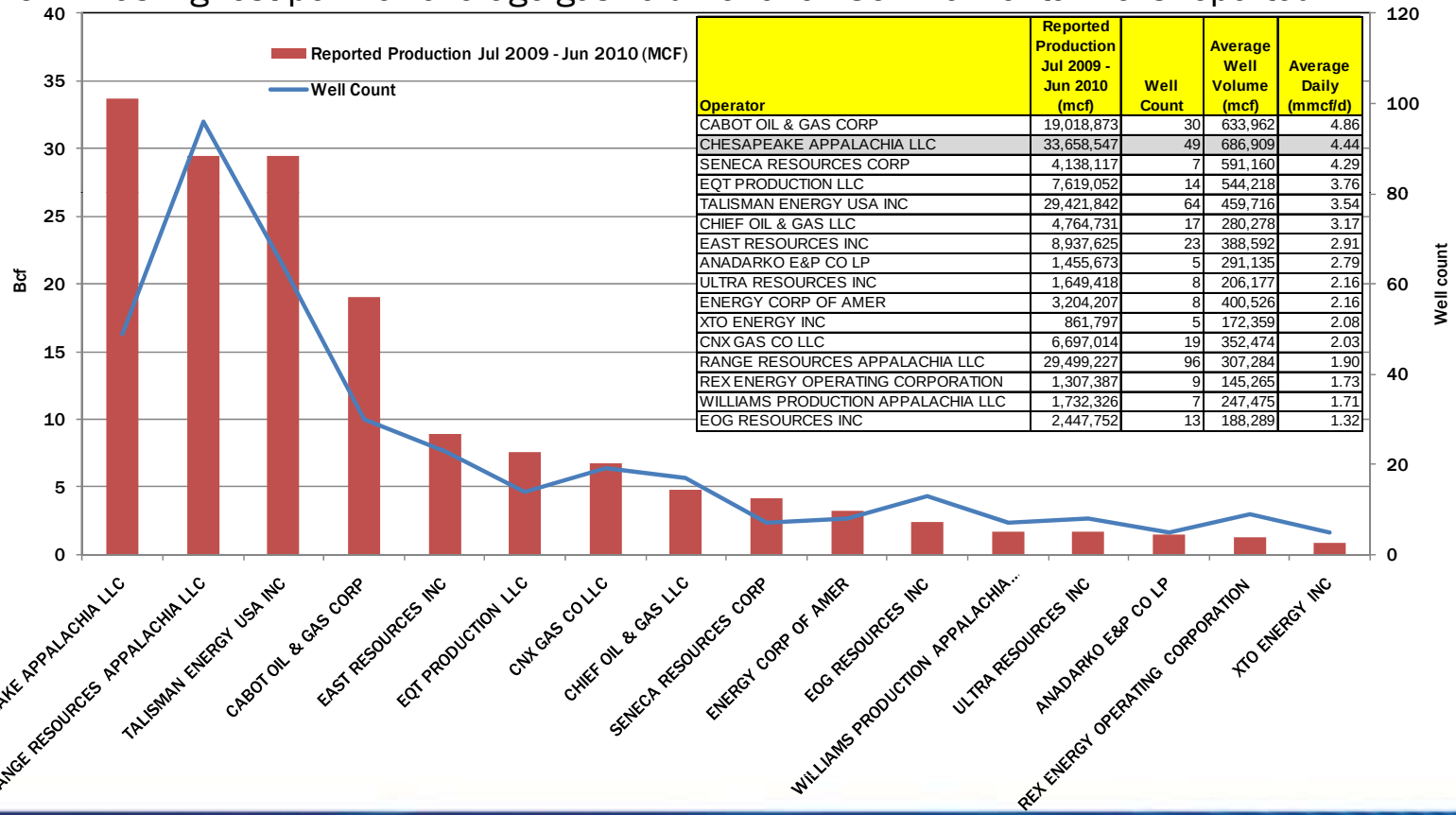
- **Moving from exploration to development phase in two sweet spots**
  - High-graded leasing efforts
  - Well results exceeded expectations
- **NE Pennsylvania Core**
  - Dry gas area
  - 20 rigs active
- **SW PA - WV Core**
  - Wet gas area
  - 7 rigs active
- **Limited exploration and data gathering in remaining areas**



Preliminary production data from DEP website, horizontal wells only, gas production only

PA Marcellus Production Data
(7/1/09 - 6/30/10)

- **CHK is top Marcellus producer in Pennsylvania based on recently released PA state data and the leader in per wells results**
  - CHK has 8 of top 15 horizontal wells with 6-12 months of reported production (179 wells)
  - CHK has highest per well average gas volume for all 392 horizontal wells reported

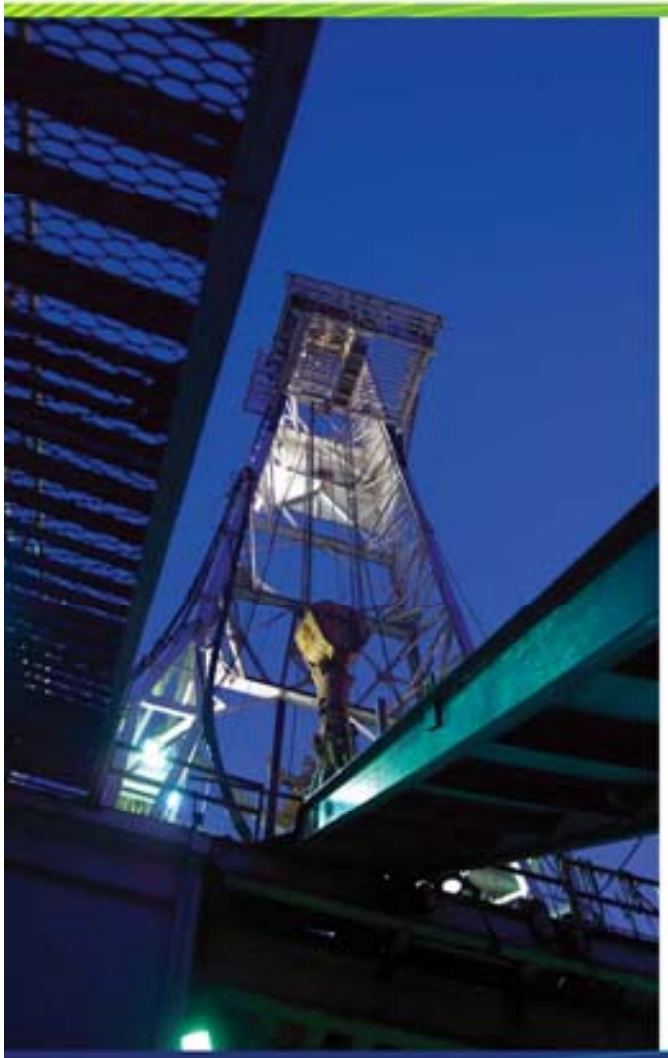


Operator	Reported Production Jul 2009 - Jun 2010 (mcf)	Well Count	Average Well Volume (mcf)	Average Daily (mmcf/d)
CABOT OIL & GAS CORP	19,018,873	30	633,962	4.86
CHESAPEAKE APPALACHIA LLC	33,658,547	49	686,909	4.44
SENECA RESOURCES CORP	4,138,117	7	591,160	4.29
EQT PRODUCTION LLC	7,619,052	14	544,218	3.76
TALISMAN ENERGY USA INC	29,421,842	64	459,716	3.54
CHIEF OIL & GAS LLC	4,764,731	17	280,278	3.17
EAST RESOURCES INC	8,937,625	23	388,592	2.91
ANADARKO E&P CO LP	1,455,673	5	291,135	2.79
ULTRA RESOURCES INC	1,649,418	8	206,177	2.16
ENERGY CORP OF AMER	3,204,207	8	400,526	2.16
XTO ENERGY INC	861,797	5	172,359	2.08
CNX GAS CO LLC	6,697,014	19	352,474	2.03
RANGE RESOURCES APPALACHIA LLC	29,499,227	96	307,284	1.90
REX ENERGY OPERATING CORPORATION	1,307,387	9	145,265	1.73
WILLIAMS PRODUCTION APPALACHIA LLC	1,732,326	7	247,475	1.71
EOG RESOURCES INC	2,447,752	13	188,289	1.32

Preliminary production data from DEP website, horizontal wells only, gas production only

Best science + best acreage + best operations = best wells!

Marcellus Shale – Last 12 Months



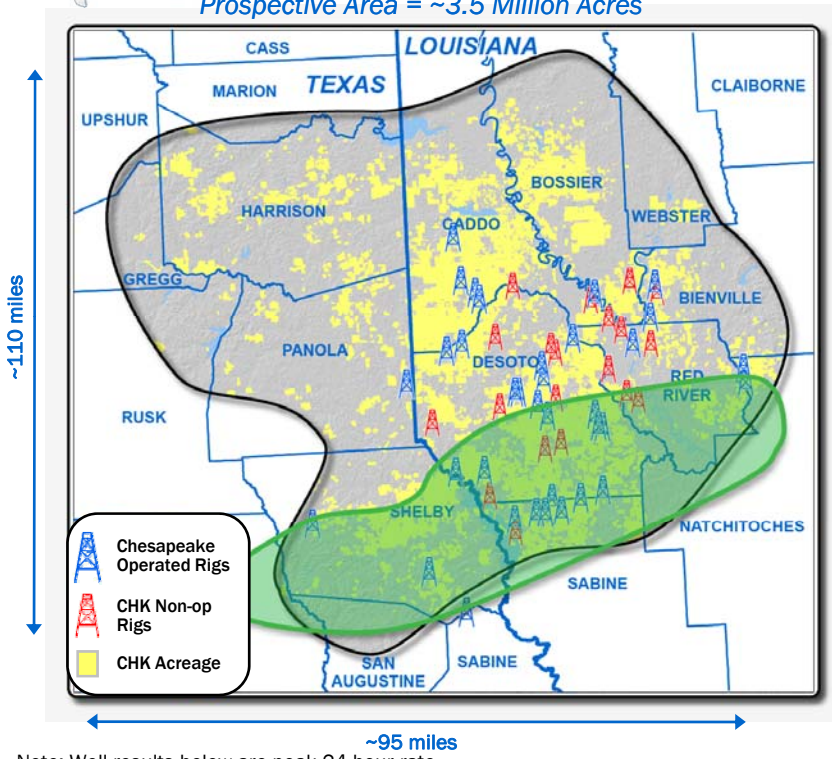
- **Important developments**
  - Ramped up to 27 rigs in play
  - Major trunk line taps and gathering system designs in place
  - Identified two sweet spots and began consolidating acreage position
- **Significant accomplishments since 2009 Investor and Analyst Meeting**
  - Raised average EUR from 4.2 bcfe to 5.25 bcfe
  - Increased land position to 1.55 mm net acres
  - Drilling carry yields 2010 field finding costs of < $0.50/mcfe
- **Opportunities for future productivity and efficiency gains**
  - Compression projects initiated
  - Allocation of rigs to best areas
  - Data gathering and surveillance
  - Pad drilling after acreage is HBP
  - Consolidation of acreage through trades for efficient development

Transitioning from land grab to de-risk to development

Haynesville and Bossier Shales Highlights

Haynesville Shale – Overview

Prospective Area = ~3.5 Million Acres



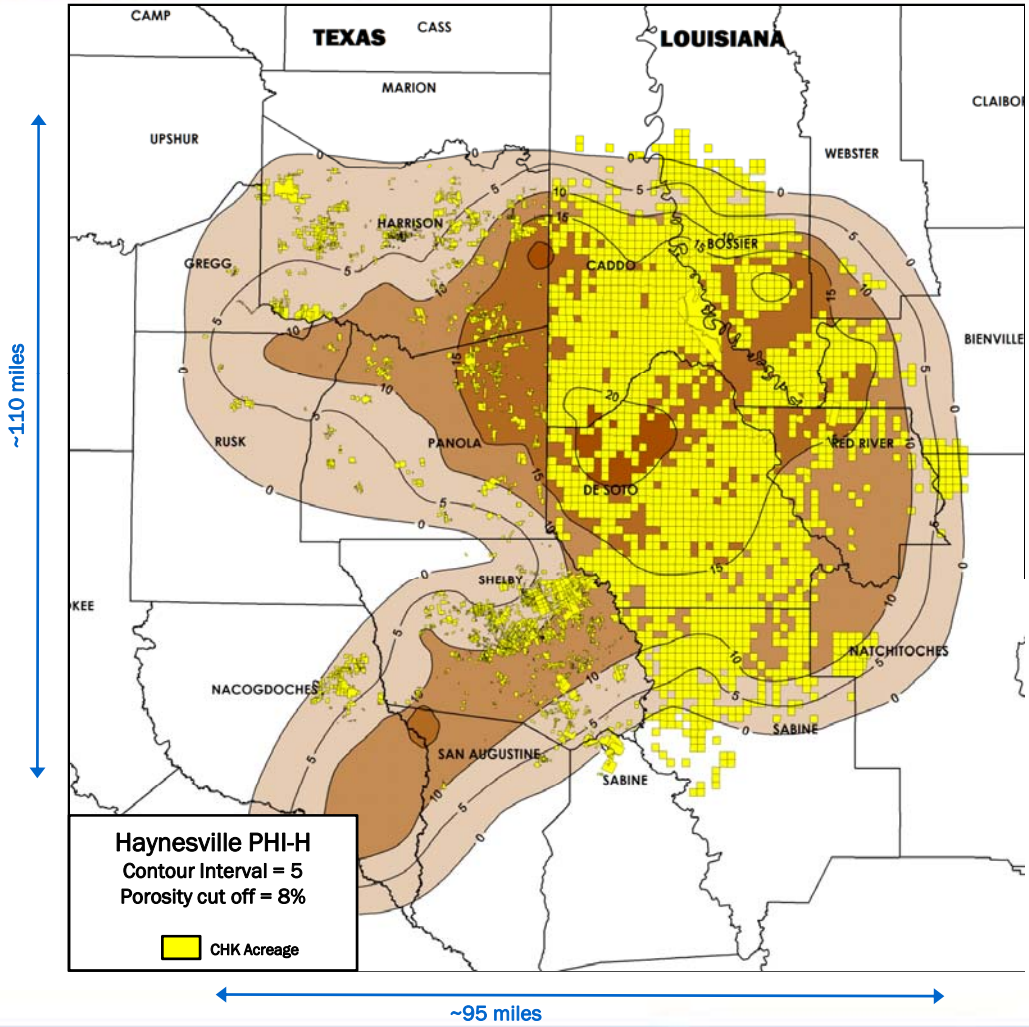
Note: Well results below are peak 24-hour rate

1Q '10 Wells	2Q '10 Wells	3Q '10 Wells
Fuller 8-13-13 H-1 23.7 mmcf/d	Brasch Family 3-13-13 H-1 22.0 mmcf/d	Nabors Properties 31 H-1 19.5 mmcf/d
Pankey 23-14-15 H-1 18.9 mmcf/d	Sloan 9-13-13 H-1 22.2 mmcf/d	Renfro 15-13-13 H-1 17.8 mmcf/d
Sloan 4-13-13 H-1 21.9 mmcf/d	Wren 10-13-13 H-1 21.6 mmcf/d	Welborn 15-10-12 H-1 19.1 mmcf/d

- Discovered by CHK in 2007, the Haynesville Shale is likely to become one of the two largest natural gas fields in the U.S. (Marcellus the other)
- CHK is the largest leasehold owner and largest producer in the play with ~530,000 net acres, primarily focused in the core
- 80/20 JV with PXP in 7/08; received $3.2 billion in cash and drilling carries for 20% sale
- CHK has 2.9 tcfe of proved reserves(1), ~20 tcfe of risked unproved resources(2) and ~29 tcfe of unrisked unproved resources(2)
- Current net production of 725 mmcfe/d(3),up ~ 175% YOY
- CHK anticipates having the vast majority of its Haynesville Shale leasehold HBP by YE 2011
- Currently operating 35 rigs in the play; plan to average ~31 rigs in '11
- CHK has ~215 net producing Haynesville wells; ~6,400 net unrisked wells left to drill

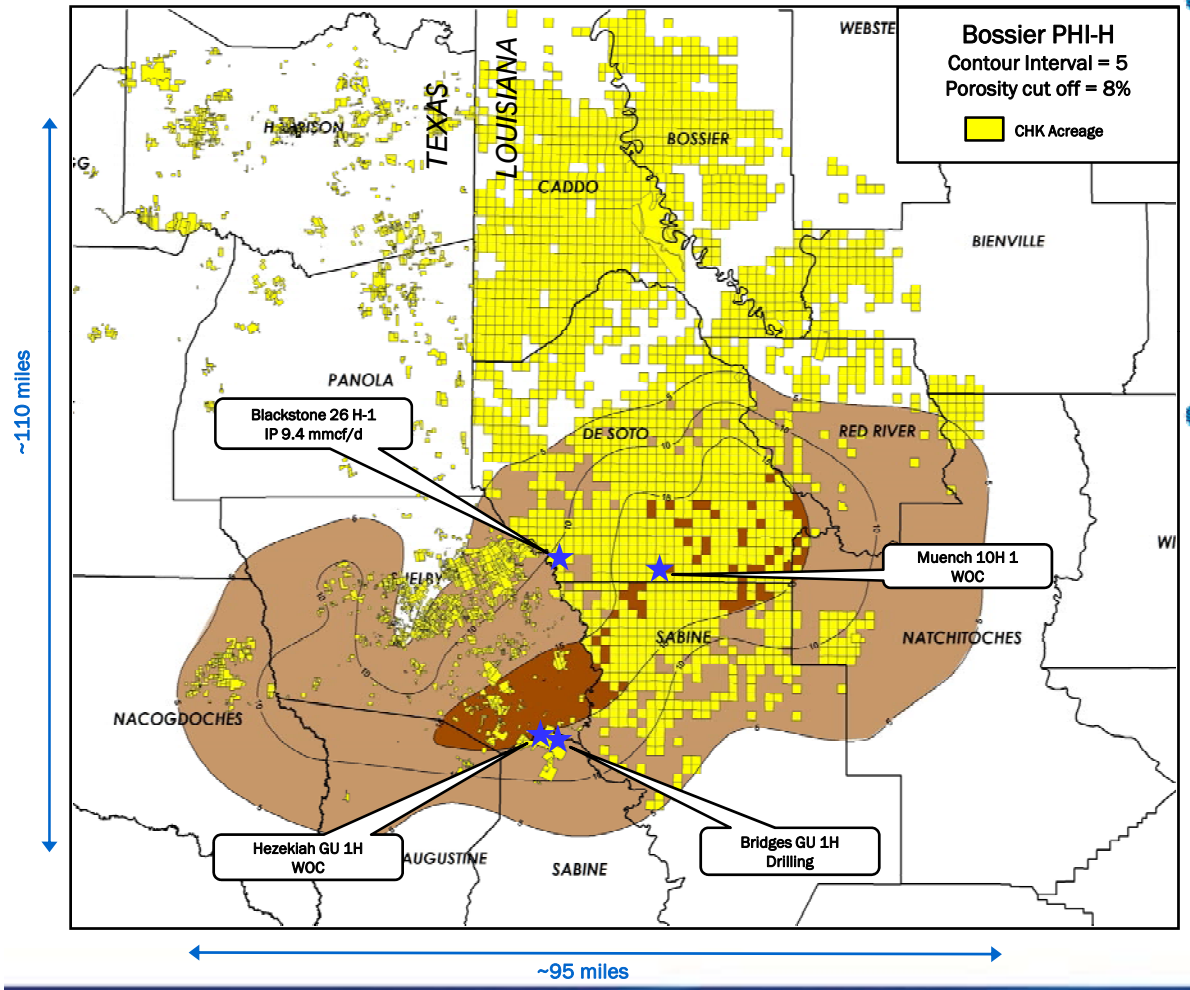
1) Based on 10-yr average NYMEX strip prices at June 30, 2010
2) Risk disclosure regarding unproved resource estimates appears on page iii of the meeting presentation package
3) September 2010 average

Haynesville Shale – Geology



- **Reservoir and geology**
  - Thick over pressured reservoirs
  - High gas-in-place and high initial recoveries
  - Good frac barriers and no water problems
  - Geologically stable area – structurally uncomplicated
  - Stacked Haynesville and Bossier potential
  - Low-risk with repeatable results
- **CHK always goes for the Core!**

Bossier Shale – Geology



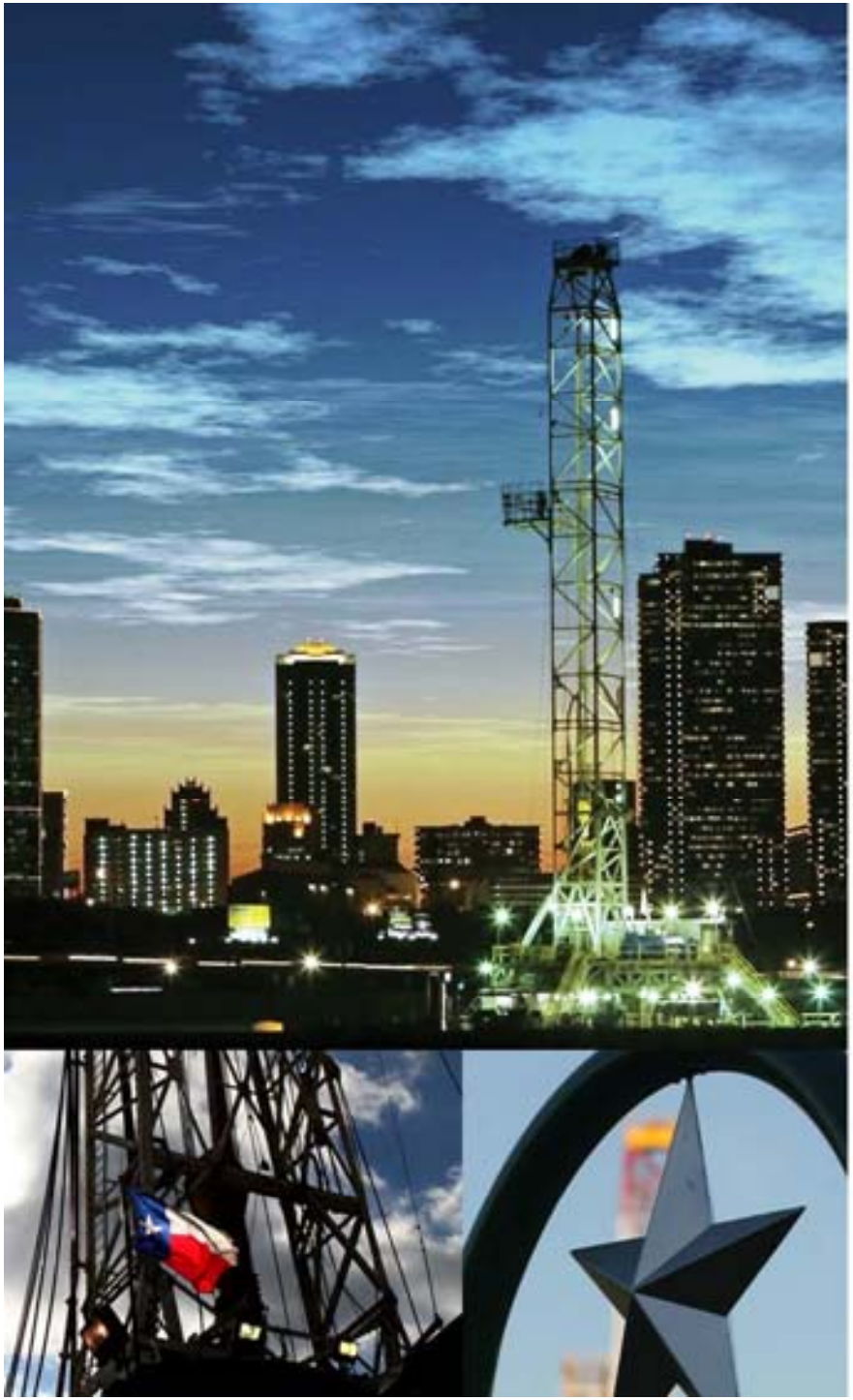
- **Quick facts**
  - Reservoir characteristics similar to Haynesville
  - Approximately 20 producing wells and an additional 20 completed or WOPL
  - 14 horizontal rigs active in play
  - Represents a low risk "gas bank" that can be developed at pace that CHK desires and when natural gas prices incentivize
- **CHK's Bossier position:**
  - Currently controls ~195,000 net acres
  - Risked unproved resources of ~4.0 tcfe
  - Unrisked unproved resources of ~10.0 tcfe

World-class reservoir held by Haynesville HBP activity for development in a better price environment

Haynesville Shale – Last 12 Months

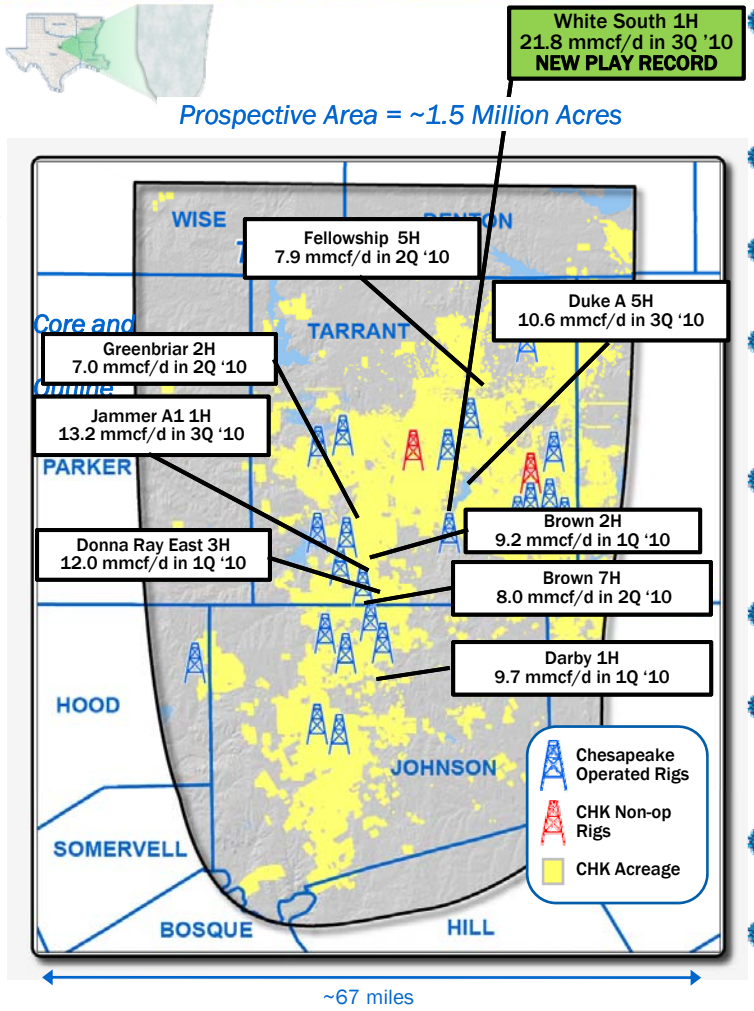
- **Important developments**
  - Secured additional frac crews
  - Significantly reduced WOPL (waiting on pipeline) inventory
  - Exceeded targeted production goals
  - Expanded Bossier footprint in East Texas
- **Significant accomplishments since 2009 Investor and Analyst Meeting**
  - Reduced spud to release from 47 to 44 days while increasing average lateral length
  - Increased proved reserves(1) from 0.7 tcfe to 2.9 tcfe
  - Increased net production from 290 to 725 mcfe/d(2)
  - Secured 525 mmcfe/d of firm transport capacity for total of 1.85 bcfe/d
  - Created 200 mmcfe/d of gathering system capacity for total of 1.3 bcfe/d
- **Opportunities for future productivity and efficiency gains**
  - Total resource definition through geo-modeling and reservoir simulation
  - Completion design refinements
  - Drilling efficiencies
  - Pad development

1) Based on 10-yr average NYMEX strip prices at June 30, 2010
2) September 2010 average



Barnett Shale Highlights

Barnett Shale – Overview



- CHK is the largest leasehold owner, most active driller and largest producer in the Core and Tier 1 sweet spot of Tarrant and Johnson Counties
- 75/25 JV with TOT in 1Q '10; $2.25 billion in cash and drilling carries
- Sold 390 bcfe of proved reserves for proceeds of $1.15 billion in VPP #8
- CHK has 2.9 tcfe of proved reserves(1),~3.4 tcfe of risked unproved resources(2) and ~4.4 tcfe of unrisked unproved resources(2)
- Current net production of 555 mmcfe/d(3)
  - The sale of VPP #8 will reduce 2011E net production by ~280 mmcfe/d
- CHK has drilled four out of the five best wells ever drilled in the Barnett
- Recently raised its targeted average EUR on its acreage by ~13% from 2.65 bcfe/well to 3.0 bcfe/well because of outstanding well performance
- Currently operating 21 rigs in the play; plan to average 19 rigs in '11
- CHK has ~1,255 net producing Barnett wells; ~2,400 net unrisked wells left to drill

Note: Well results above are peak 24-hour rate

1) Based on 10-yr average NYMEX strip prices at June 30, 2010
2) Risk disclosure regarding unproved resource estimates appears on page iii of the meeting presentation package
3) September 2010 average

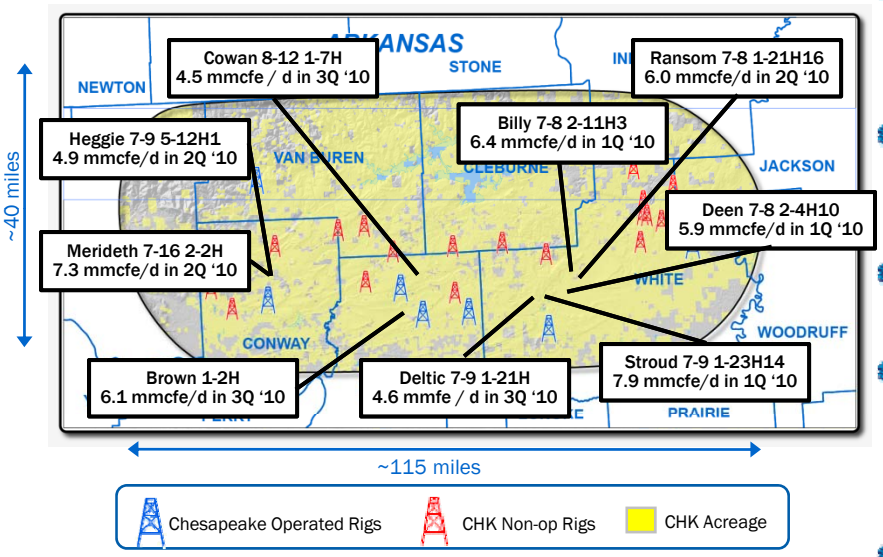
Barnett Shale – Last 12 Months

- **Important developments**
  - Executed JV agreement with Total; sold 25% interest in Barnett for $2.25 billion
  - Monetized 390 bcfe of reserves for $1.15 billion via VPP #8
  - Tarrant County sweet spot confirmed by well results
  - Best wells in play have come on in last 6 months
  - Increased highest to date IP rate to 21.8 mmcfe/d (White South 1H)
  - Limited competition for new acreage in best areas of Tarrant County
  - CHK's scale, surface control, existing pads and midstream infrastructure are a huge advantage
- **Significant accomplishments since 2009 Investor and Analyst Meeting**
  - Drilled a total of 415 wells
  - Reduced spud to rig release average by 1.7 days to 16.3 days
  - Decreased average well drilling costs by $0.16 mm to $1.24 mm
  - Increased total 3D seismic coverage to 1,143 square miles

Fayetteville Shale Highlights

Fayetteville Shale – Overview

Prospective Area = ~1.7 Million Acres



Note: Well results above are peak 24-hour rate

- CHK is the second-largest producer in the Fayetteville Shale and the second-largest leasehold owner in the Core area of the play
- 75/25 JV with BP in 9/08; $1.9 billion in cash and drilling carries
  - Drilling carries were 100% collected by YE 2009
- CHK has 2.4 tcfe of proved reserves(1),~7.7 tcfe of risked unproved resources(2) and ~10.0 tcfe of unrisked unproved resources(2)
- Current net production of 390 mmcfe/d(3), up 90% YOY
- CHK recently raised its targeted average EUR on its acreage by ~8% from 2.4 bcfe/well to 2.6 bcfe/well because of outstanding well performance
- Currently operating ~8 rigs; plan to average ~8 rigs in '11
- Should reach HBP objectives soon and reduce drilling activity in response to low natural gas prices; will preserve greater future value
- CHK has ~400 net producing Fayetteville wells; ~5,300 net unrisked wells left to drill

1) Based on 10-yr strip pricing at June 30, 2010
2) Risk disclosure regarding unproved resource estimates appears on page iii of the meeting presentation package
3) September 2010 average

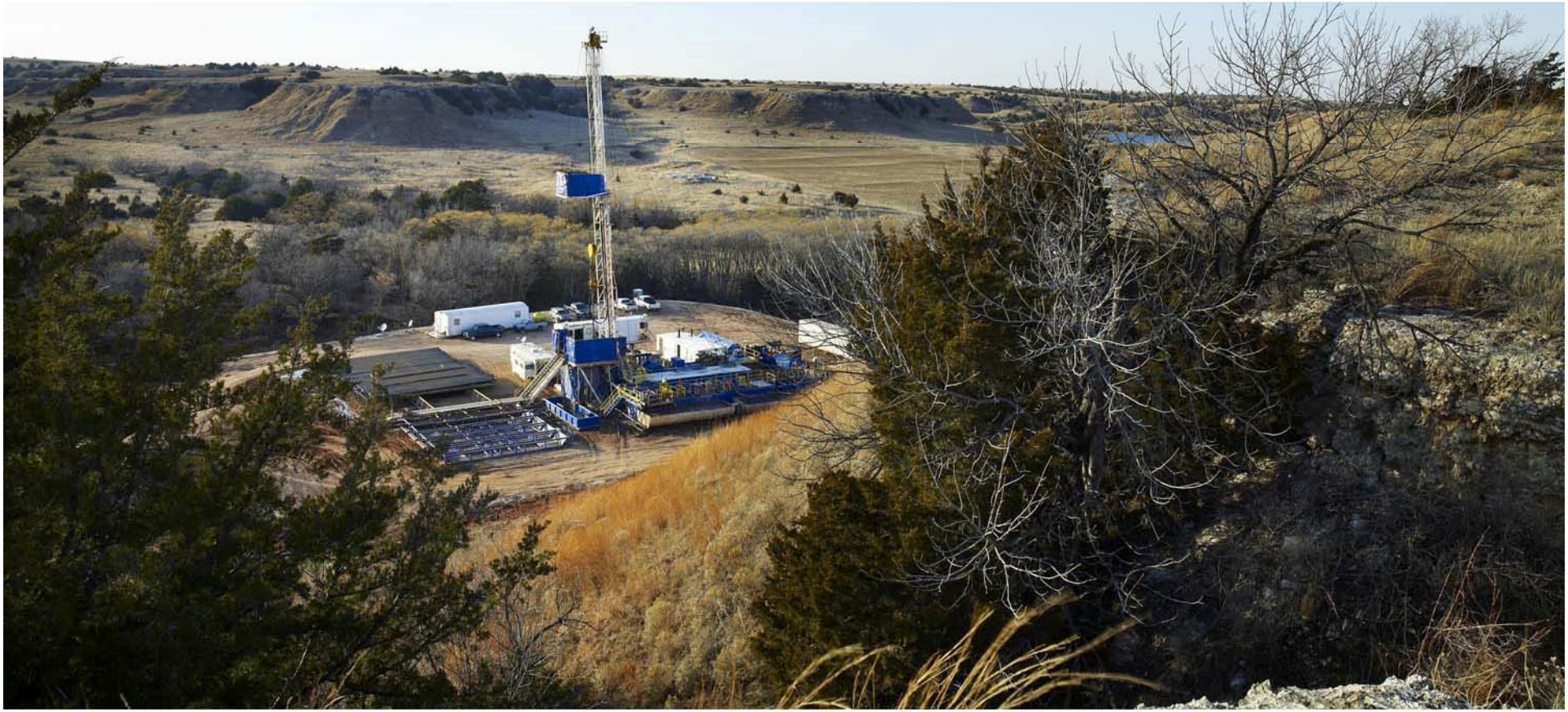
Fayetteville Shale – Last 12 Months

- **Important developments**
  - HBP 68,300 acres
  - Alleviated stranded pipeline areas
  - Deleted backlog of wells WOC or WOPL
  - Drilled and cored well on Arkansas Game and Fish lands
    - Working closely with state officials to secure “green” drilling procedures
- **Significant accomplishments since 2009 Investor and Analyst Meeting**
  - Increased proved reserves from 1.0 to 2.4 tcfe
  - Increased net production from ~205 mmcfe/d to ~390 mmcfe/d
  - Set gross production record of 565 mmcf/d on 9/5/10
  - Increased highest to-date IP rate from 6.5 mmcfe/d to 9.2 mmcfe/d (Nicholson 7-8 4-10H9)
  - Increased horizontal producers from 509 to 686
  - Increased 3D seismic acquired from 1,205 to 1,507 square miles
    - Currently permitting or shooting 61 square miles of additional 3D seismic
- **Opportunities for future productivity and efficient gains**
  - Added use of LWD for better targeting and more efficient frac design
    - Helps alleviate ambiguous steering interpretations
    - Pad increased drilling density

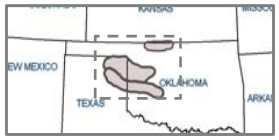
Anadarko Basin Plays

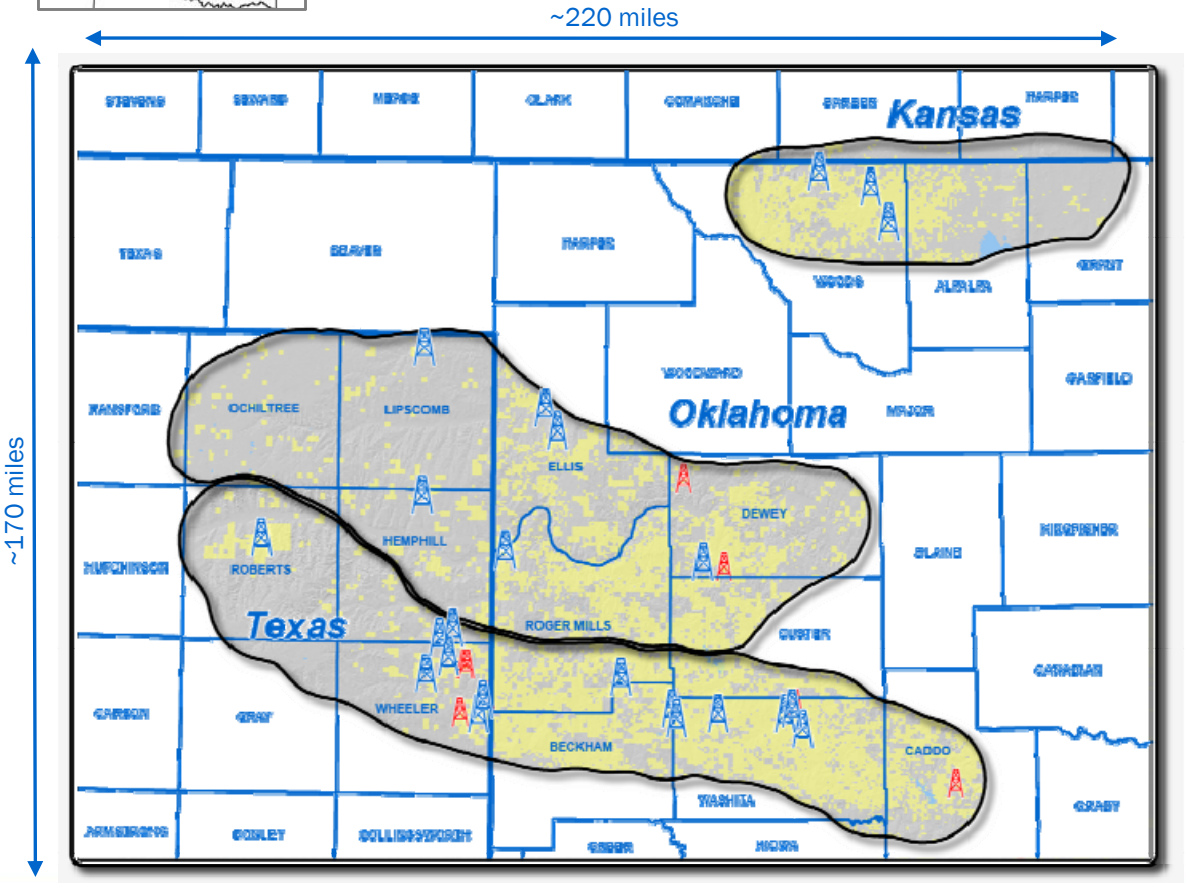
Granite Wash, Cleveland/Tonkawa and Mississippian

Scott Sachs, Vice President - Geoscience, Northern Division



Anadarko Basin – Horizontal Liquids Play Overview

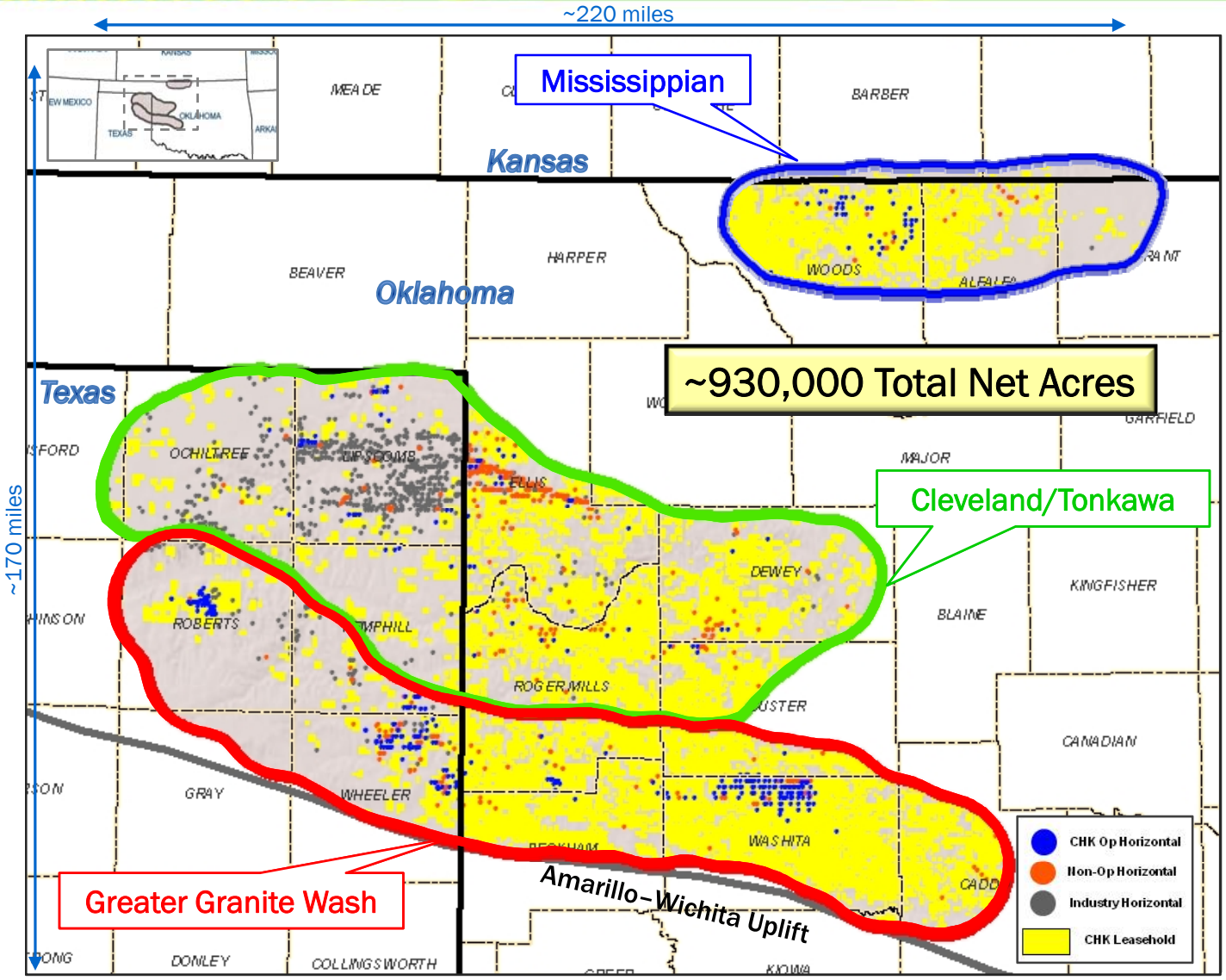




- Anadarko Basin is the largest non-shale resource play in the Mid-Continent
- CHK was the first to utilize modern horizontal drilling and has lead technology improvements
- CHK has assembled an unrivaled 930,000 net acre leasehold position in numerous horizontal liquids-rich plays
- CHK is the most active horizontal driller with 23 operated rigs
- Successful track record in all key horizontal plays
  - Granite Wash
  - Cleveland/Tonkawa
  - Mississippian

Vast acreage position to develop in the lucrative liquids-rich plays; CHK dominates the Mid-Continent!

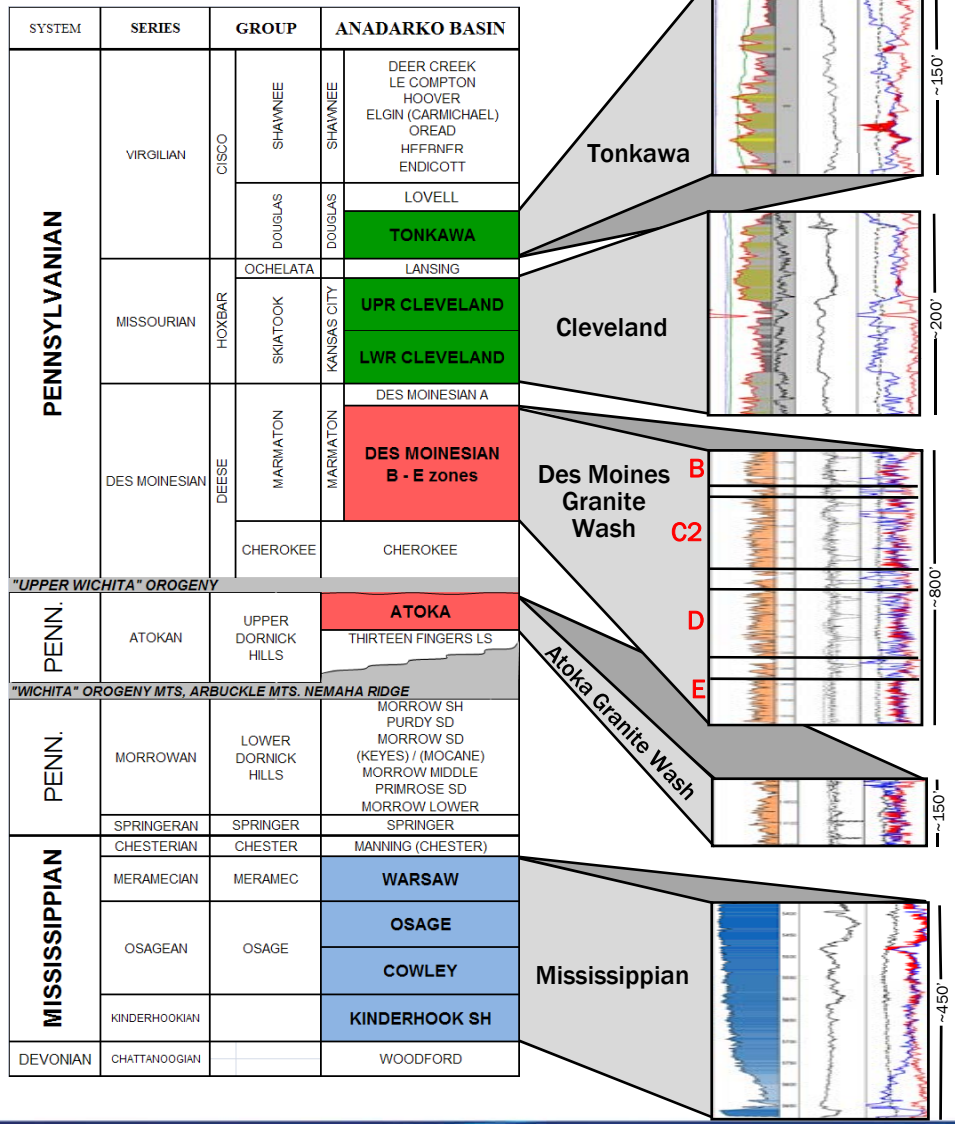
Anadarko Basin and CHK Domination

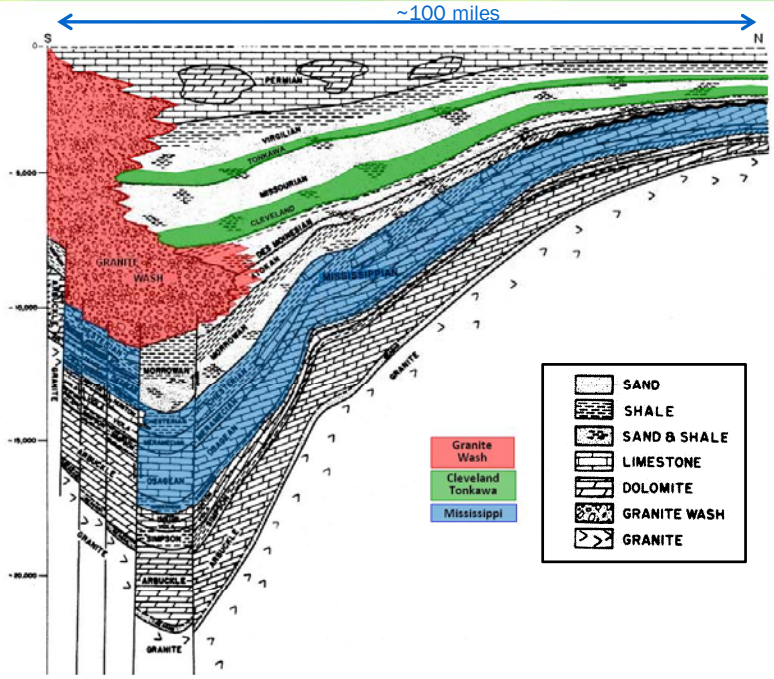


- **Abundant well and seismic data**
  - >2.4 MM acres of 3D data
- **Target-rich environment for tight sand objectives**
- **Strong oil and NGL components drive superior economics**
- **Vertical to horizontal evolution**
  - Drilling conventional & unconventional reservoirs
- **Extensive leasehold**
  - Greater Granite Wash: ~200,000 net acres
  - Cleveland/Tonkawa: ~500,000 net acres
  - Mississippian: ~230,000 net acres

CHK has a massive advantage over all peers, particularly in western Oklahoma

Anadarko Basin–Reservoir Architecture

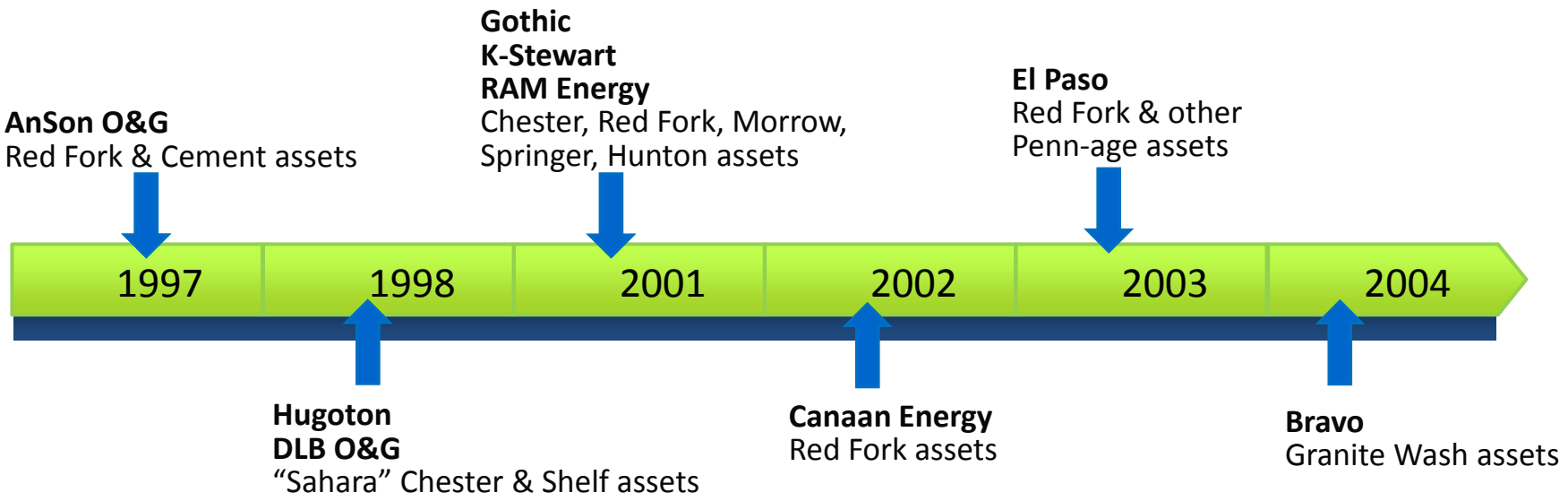




- **Colony Granite Wash**
  - 2 to 3 prospective Granite Wash zones
- **Texas Panhandle Granite Wash**
  - 2 to 5 stacked prospective Granite Wash zones
- **Cleveland/Tonkawa**
  - Thick marine shelf silty sandstone targets
- **Mississippian**
  - "Stair-stepped" unconformity enhanced porosity zones

Anadarko Basin – CHK's Playground

- CHK has been drilling in the Anadarko Basin since 1990
- Key Anadarko acquisitions which, along with our own leasing efforts, built the unique Anadarko Basin asset base that has propelled CHK's growth in the basin



- Initial efforts on the shelf were focused on vertical drilling on the Mississippian Chester limestone, Pennsylvanian Red Fork and Springer sandstones
- Later, the deep basin emerged with success on the Pennsylvanian Morrow/Springer sandstones and the Devonian Hunton limestone
  - CHK's only active Anadarko Basin vertical program is the successful 3D seismic-based deep Morrow/Springer

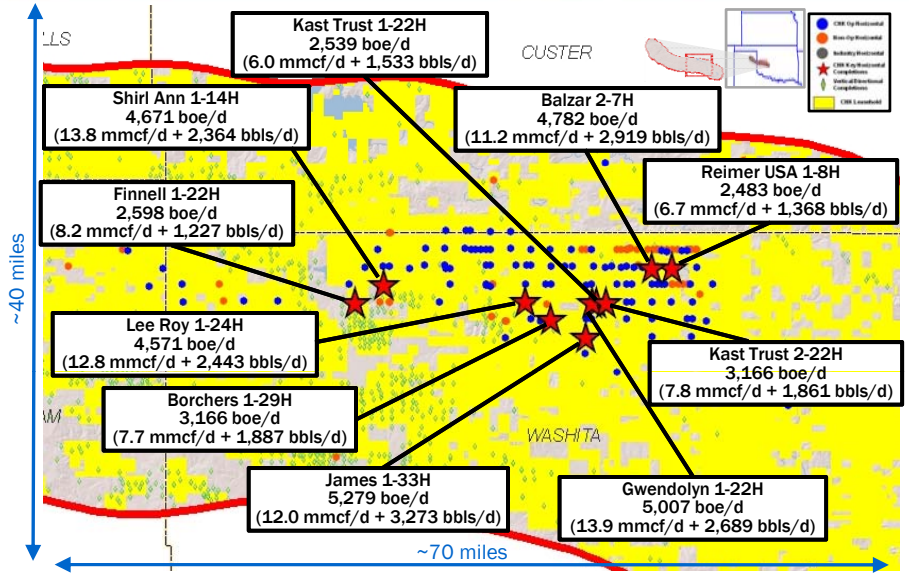
Anadarko Basin Liquids – Leader in the Play

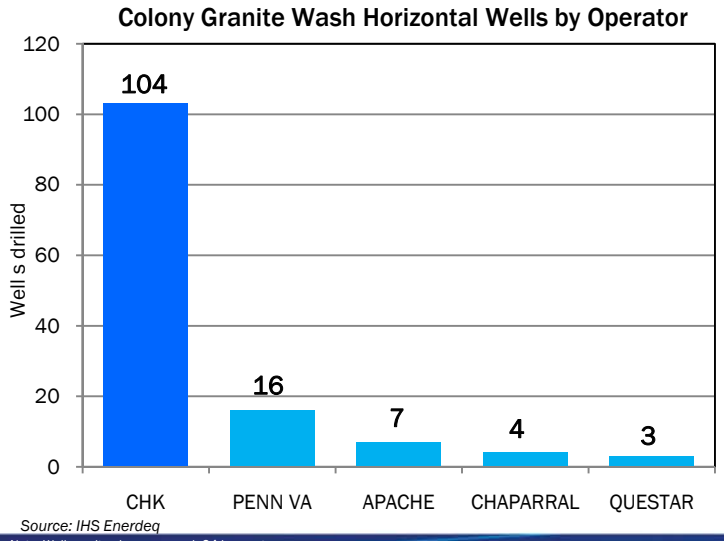
- **CHK: Earliest and largest unconventional Anadarko Basin liquids player**
  - CHK has been drilling horizontal Anadarko Basin wells for 20 years
- **Transfer of shale completion experience and technology**
  - Utilizing enhanced drilling technologies, better mud systems and improved downhole configuration has resulted in quicker and cheaper drilling
    - Lower cost, better returns and lower economic threshold
  - Application of advanced frac technologies
    - Through more stages, we are accessing more rock and enhancing recoveries
- **To date, CHK has completed:**
  - 104 Colony Wash horizontal wells; 1st well completed in February 2007
  - 68 Texas Panhandle horizontal wells; 1st well completed in June 2007
  - 30 Mississippian horizontal wells; 1st well completed in April 2007
  - 55 Cleveland horizontal wells; 1st well completed in December 2005
  - 7 Tonkawa horizontal wells; 1st well completed in March 2008

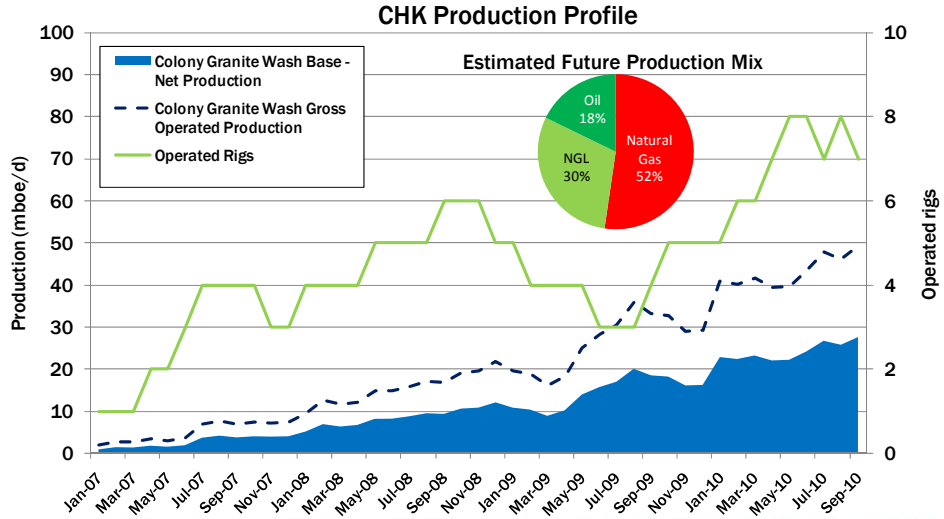
Highest rates of return in CHK's portfolio – CHK's quiet giant

Anadarko Basin – Colony Granite Wash Completions

- **Colony Granite Wash**
  - CHK has 130,000 net acres
  - Reserve and resource potential
    - 100 mmboe of proved reserves(1)
    - ~450 mmboe of risked unproved resources(2)
    - ~620 mmboe unrisked unproved resources(2)
  - Current net production of 28 mboe/d(3)
  - Currently operating 7 rigs in the play; plan to average 9 rigs in '11 to drill ~50 net wells





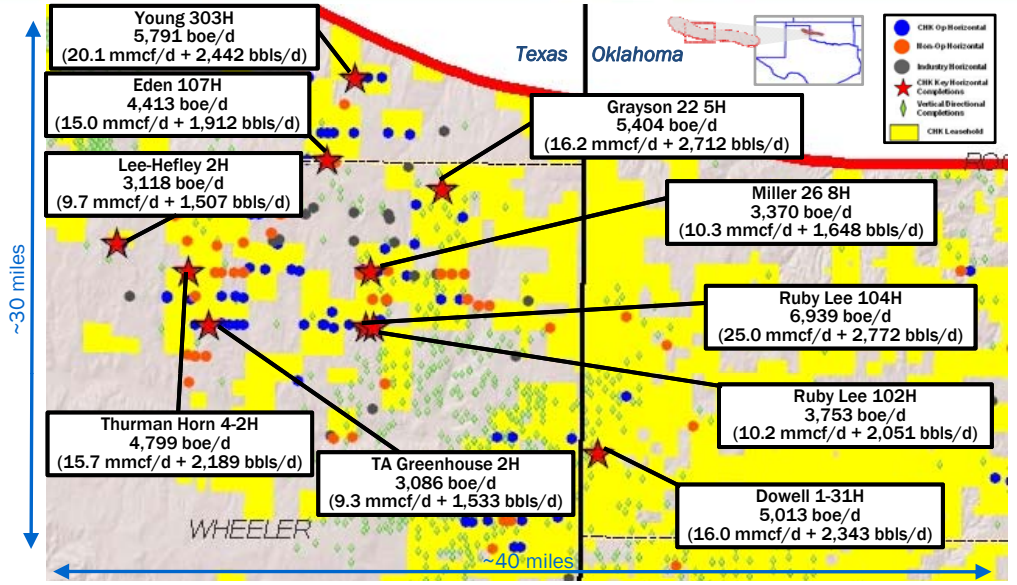


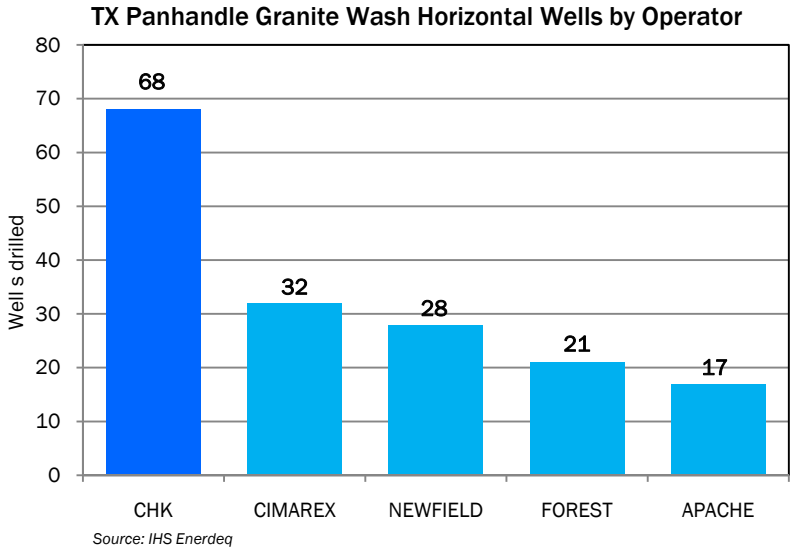
Source: IHS Enerdeq

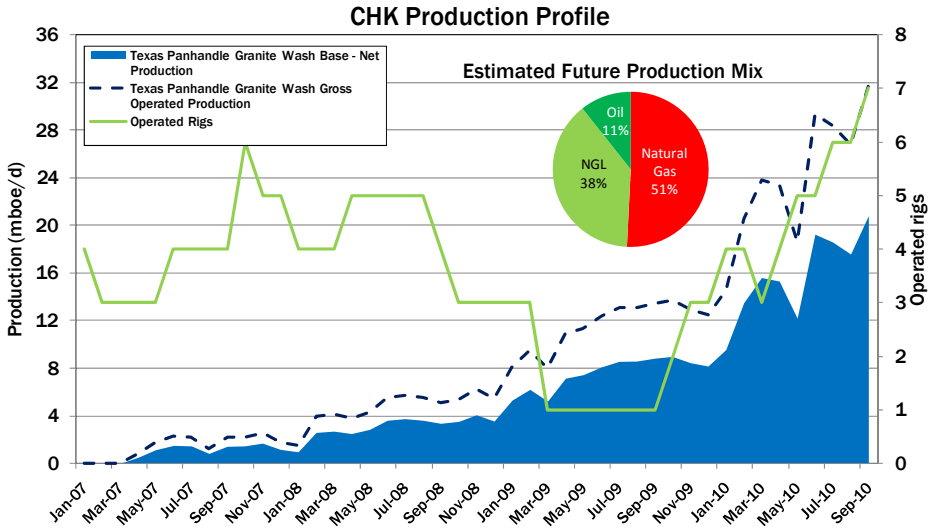
Note: Well results above are peak 24-hour rate
1) Based on 10-yr average NYMEX strip prices at June 30, 2010
2) Risk disclosure regarding unproved resource estimates appears on page iii of the meeting presentation package
3) September 2010 average

Anadarko Basin – TX Panhandle Granite Wash Completions

- **TX Panhandle Granite Wash**
  - CHK has 70,000 net acres
  - Reserve and resource potential
    - 110 mmboe of proved reserves(1)
    - ~490 mmboe of risked unproved resources(2)
    - ~685 mmboe unrisked unproved resources(2)
  - Current net production of 21 mboe/d(3)
  - Currently operating 7 rigs in the play; plan to average 7 rigs in '11 to drill ~50 net wells





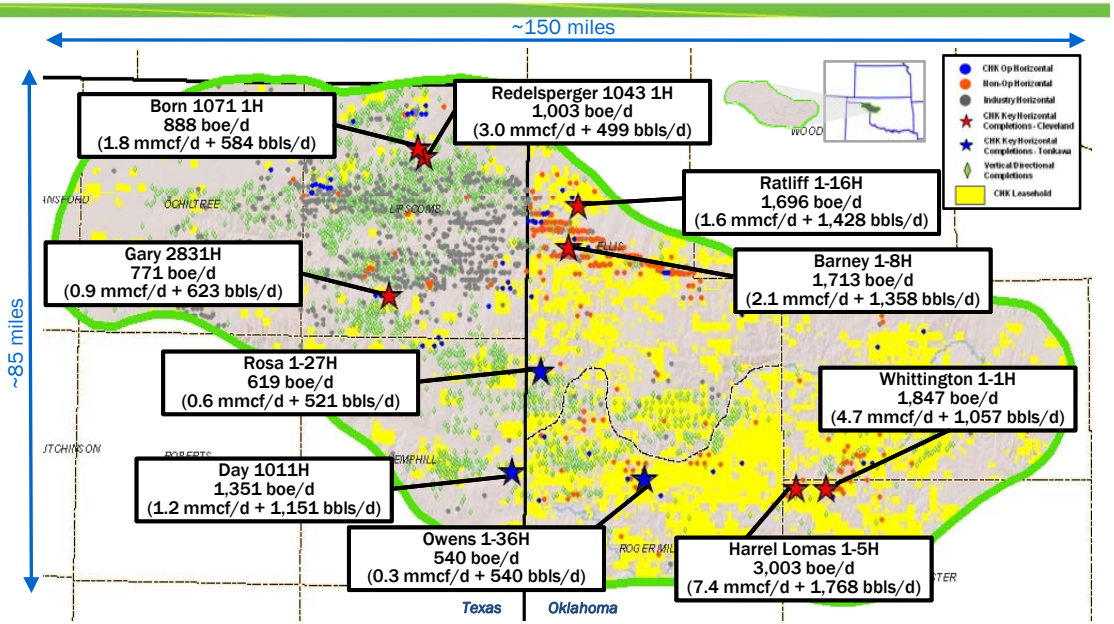


Note: Well results above are peak 24-hour rate
1) Based on 10-yr average NYMEX strip prices at June 30, 2010
2) Risk disclosure regarding unproved resource estimates appears on page iii of the meeting presentation package
3) September 2010 average

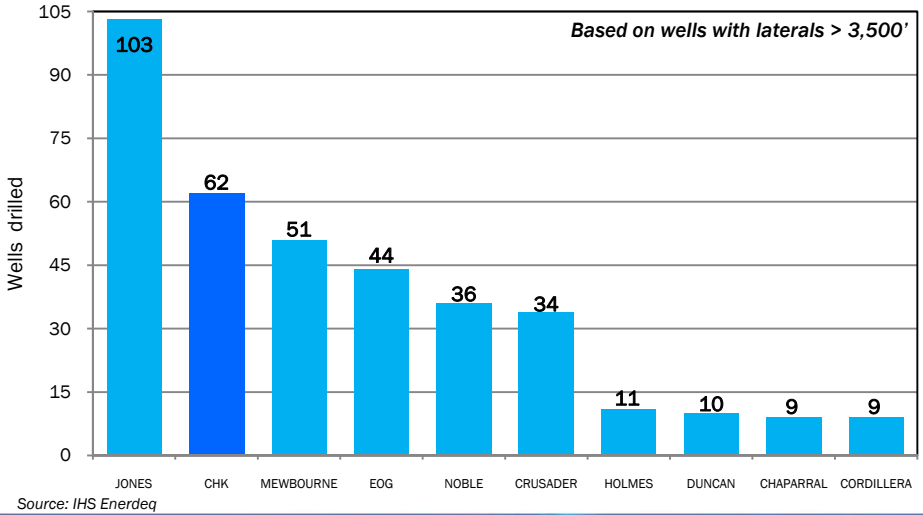
Anadarko Basin – Cleveland/Tonkawa Completions

Cleveland/Tonkawa

- CHK has 500,000 net acres
- Reserve and resource potential
  - 30 mmboe of proved reserves(1)
  - ~435 mmboe of risked unproved resources(2)
  - ~1,800 mmboe unrisked unproved resources(2)
- Current net production of 8 mboe/d(3)
- Currently operating 6 rigs in the play; plan to average 9 rigs in '11 to drill ~85 net wells

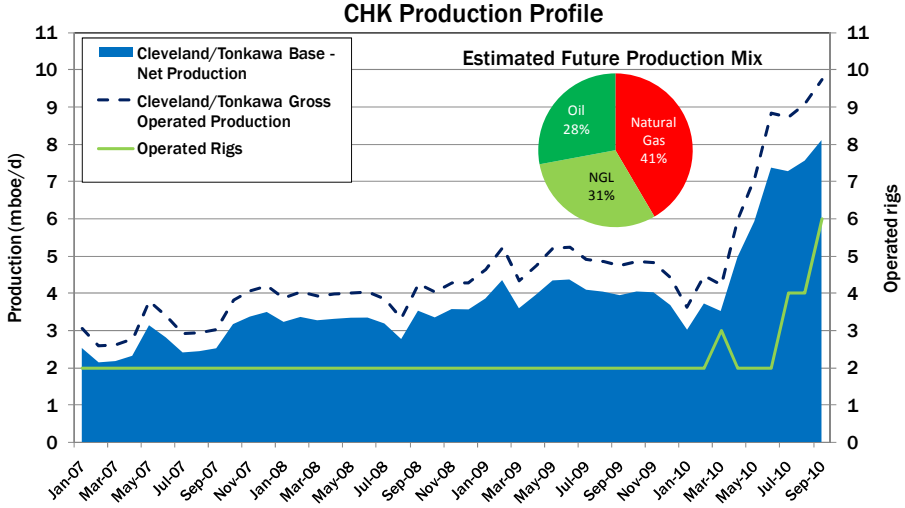


Cleveland/Tonkawa Horizontal Wells by Operator



Source: IHS Enerdeq

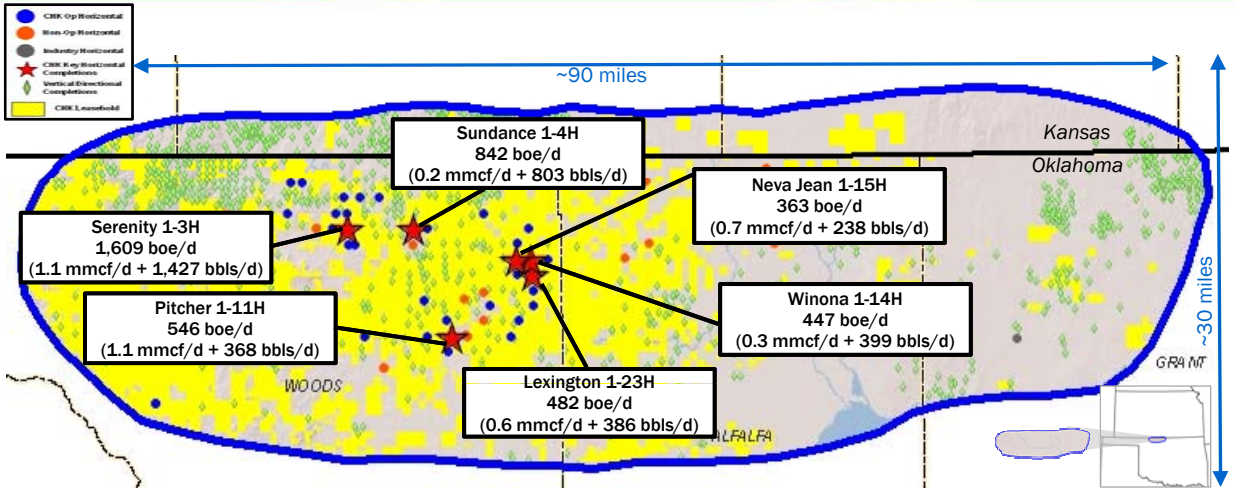
CHK Production Profile

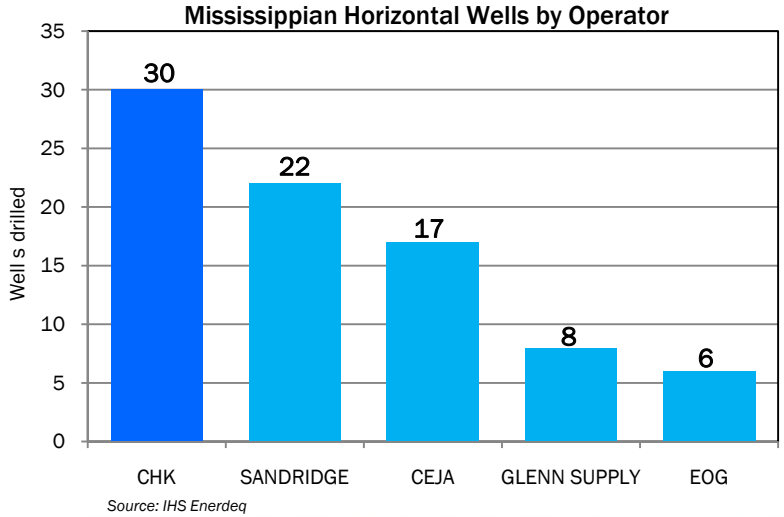


Note: Well results above are peak 24-hour rate
1) Based on 10-yr average NYMEX strip prices at June 30, 2010
2) Risk disclosure regarding unproved resource estimates appears on page iii of the meeting presentation package
3) September 2010 average

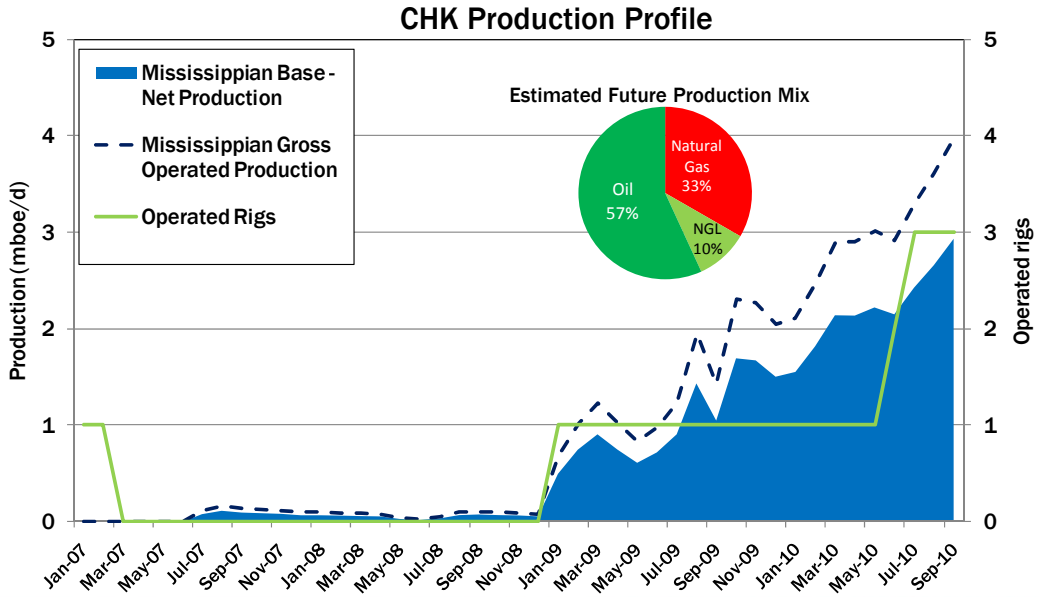
Anadarko Basin – Mississippian Completions

- **Mississippian**
  - CHK has 230,000 net acres
  - Reserve and resource potential
    - 21 mmboe of proved reserves(1)
    - ~145 mmboe of risked unproved resources(2)
    - ~385 mmboe unrisked unproved resources(2)
  - Current net production of 3 mboe/d(3)
  - Currently operating 3 rigs in the play; plan to average 4 rigs in '11 to drill ~40 net wells





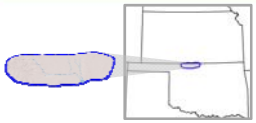
Source: IHS Enerdeq

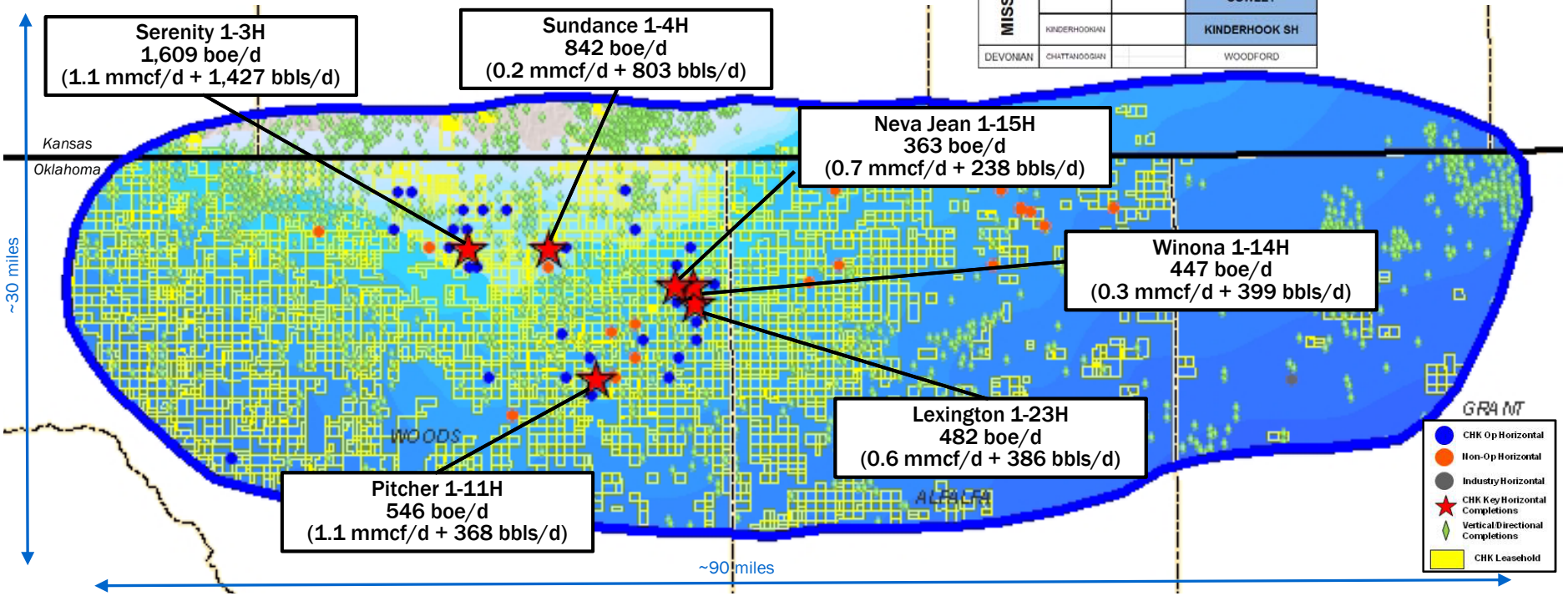


Note: Well results above are peak 24-hour rate
1) Based on 10-yr average NYMEX strip prices at June 30, 2010
2) Risk disclosure regarding unproved resource estimates appears on page iii of the meeting presentation package
3) September 2010 average

Anadarko Basin – Mississippian Vertical to Horizontal Evolution

SYSTEM	SERIES	GROUP	ANADARKO BASIN
"WICHITA" OROGENY MTS, ARBUCKLE MTS. NEMAHA RIDGE			
PENN.	MORROWAN	LOWER DORNICK HILLS	MORROW SH PURDY SD MORROW SD (KEYES) / (MOCANE) MORROW MIDDLE PRIMROSE SD MORROW LOWER
	SPRINGERAN	SPRINGER	SPRINGER
MISSISSIPPIAN	CHESTERIAN	CHESTER	MANNING (CHESTER)
	MERAMECIAN	MERAMEC	WARSAW
	OSAGEAN	OSAGE	OSAGE
			COWLEY
	KINDERHOOKIAN		KINDERHOOK SH
DEVONIAN	CHATTANOOGIAN		WOODFORD

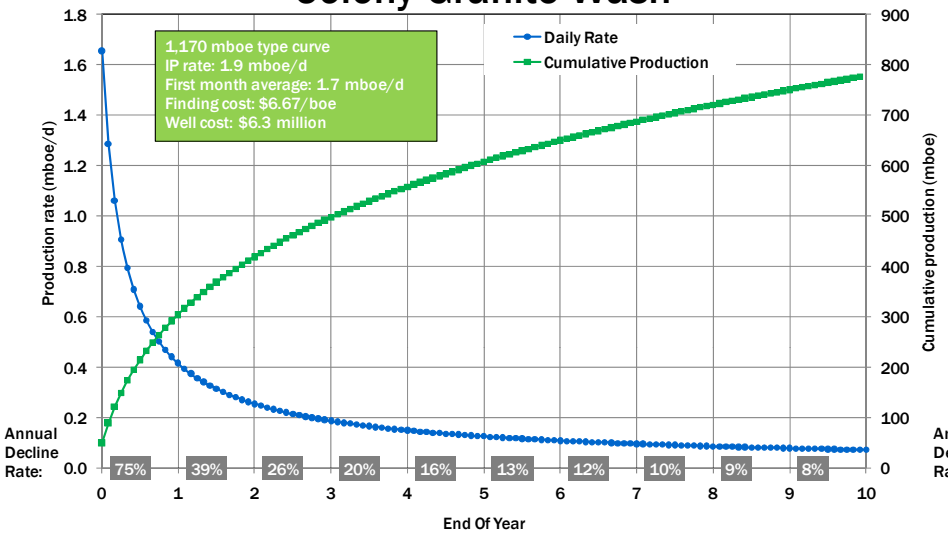




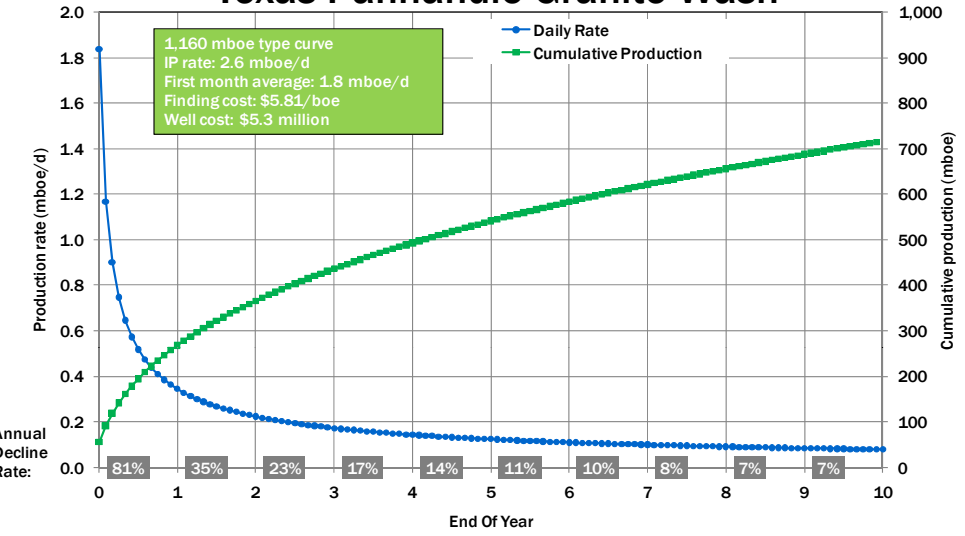
Note: IP defined as peak 24-hour rate

Anadarko Basin – Targeted Well Profiles

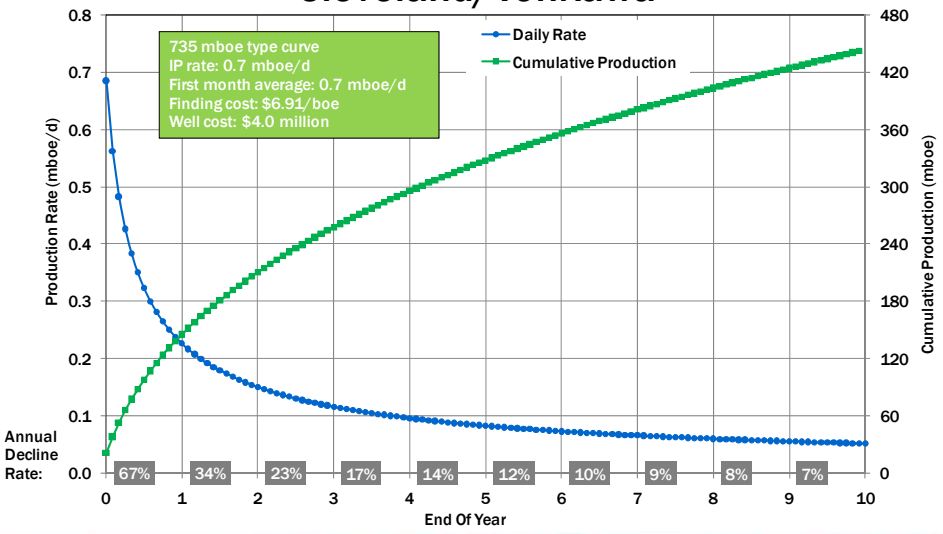
Colony Granite Wash



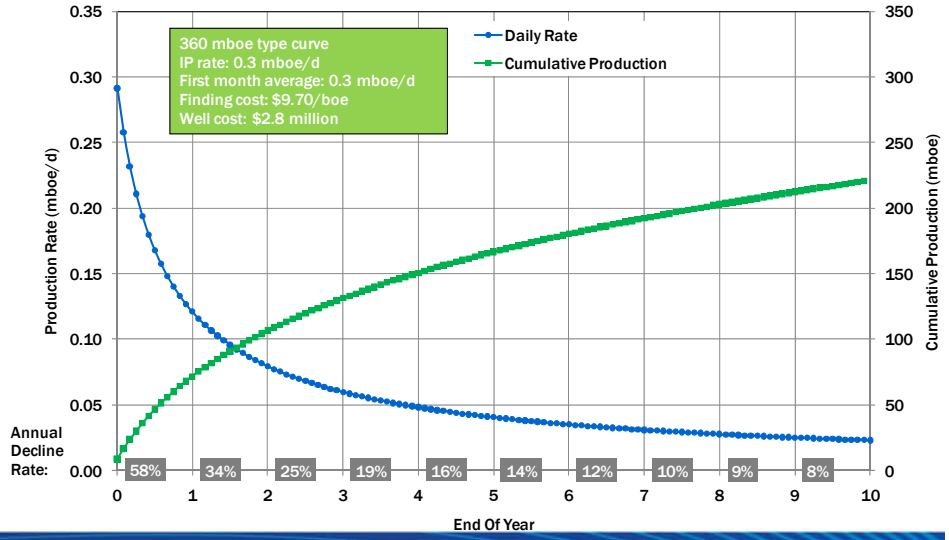
Texas Panhandle Granite Wash



Cleveland/Tonkawa

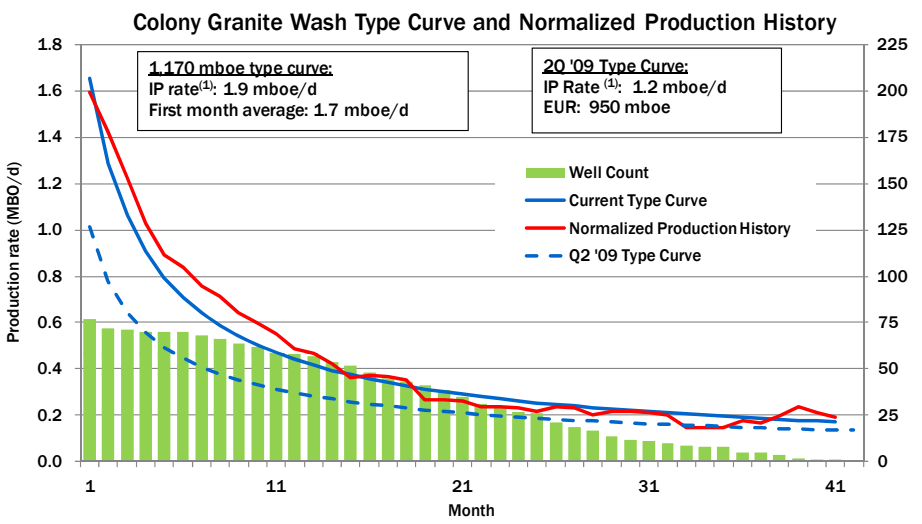


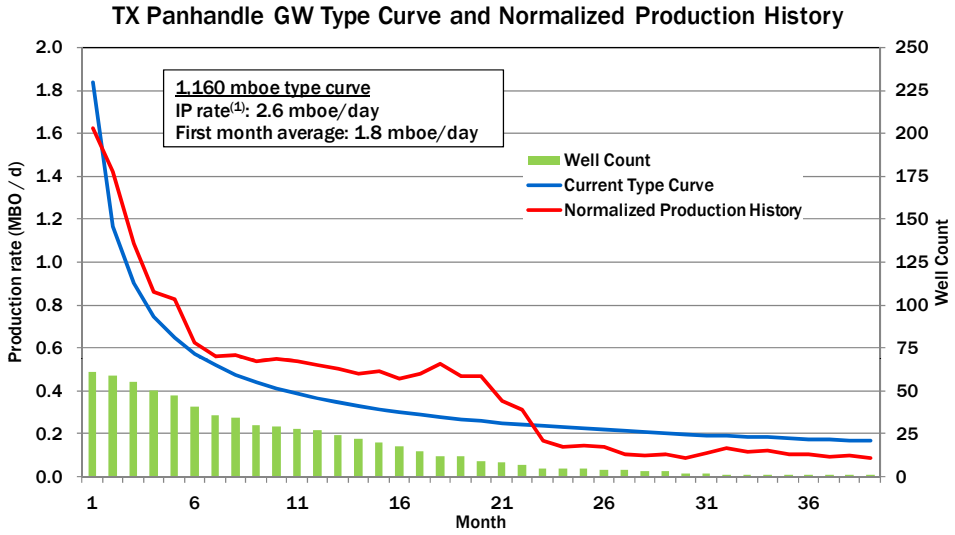
Mississippian

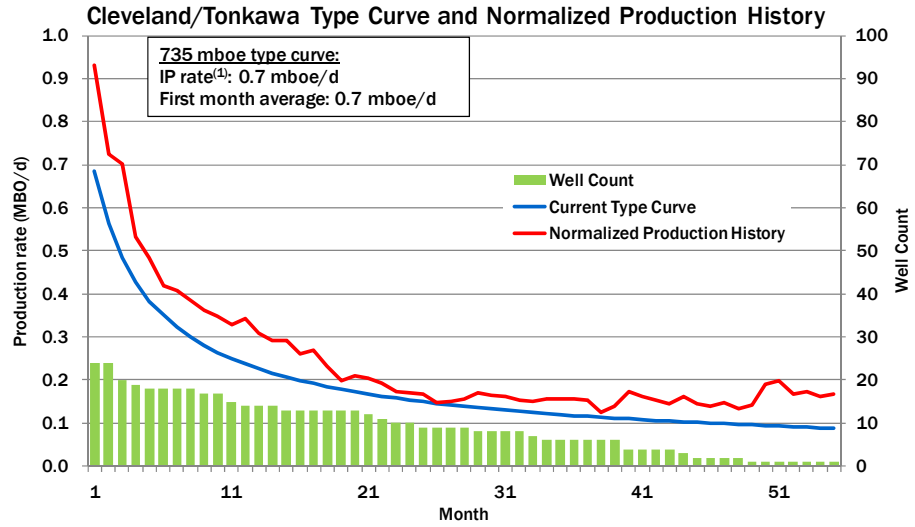


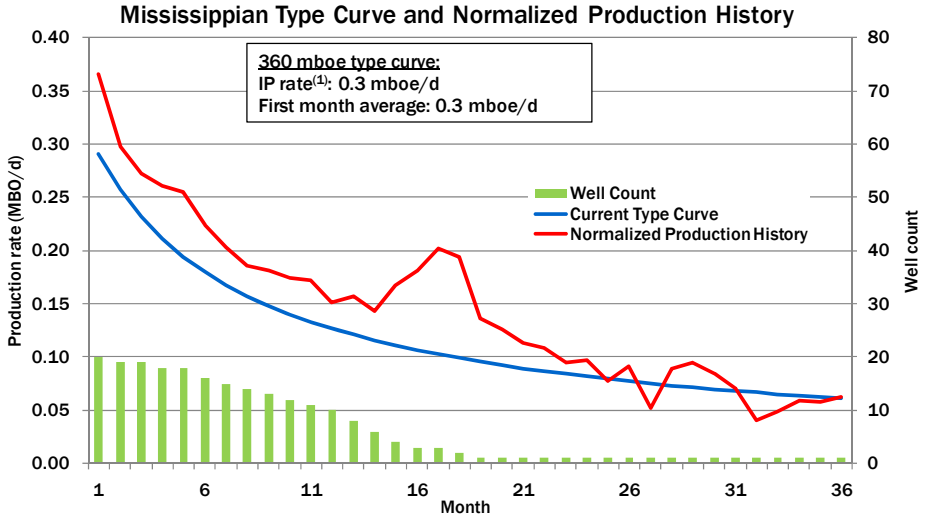
Note: IP defined as peak 24-hour rate

Anadarko Basin – Results to Date





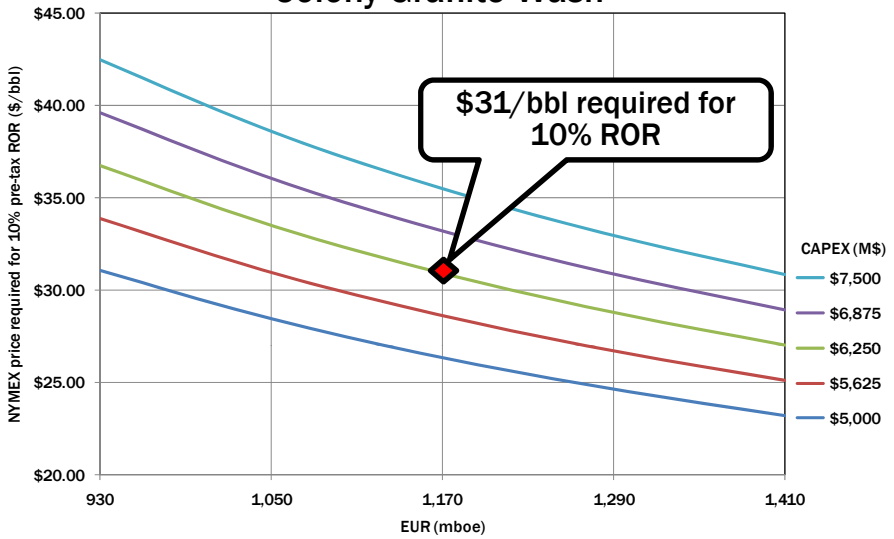




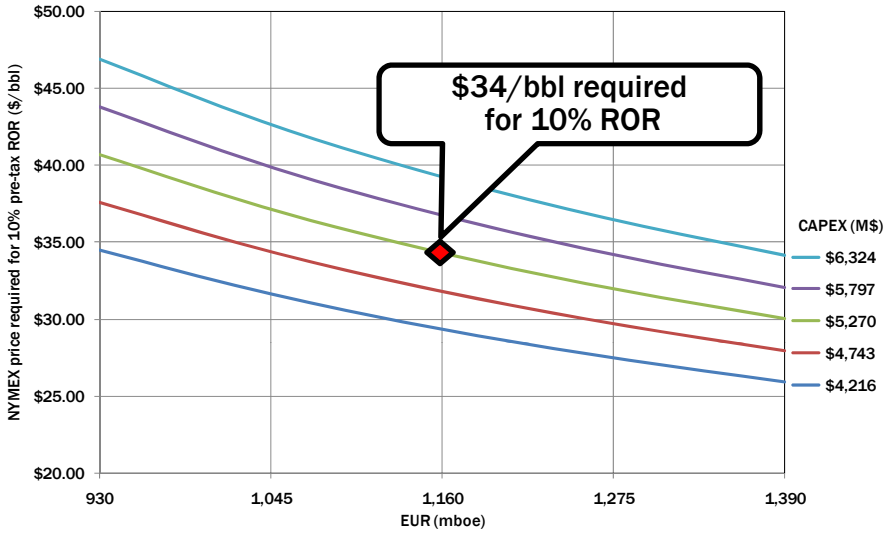
(1) Peak 24-hour rate

Anadarko Basin – PV10 Sensitivity

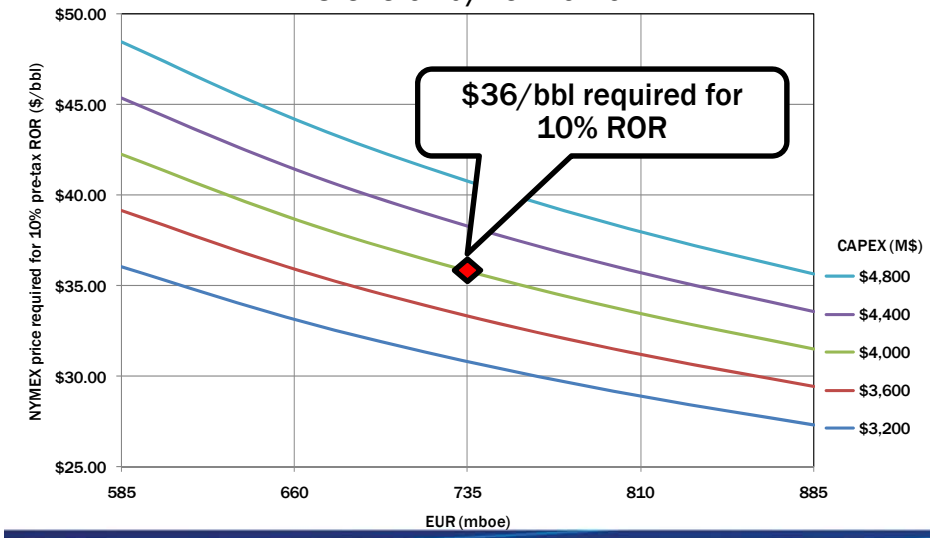
Colony Granite Wash



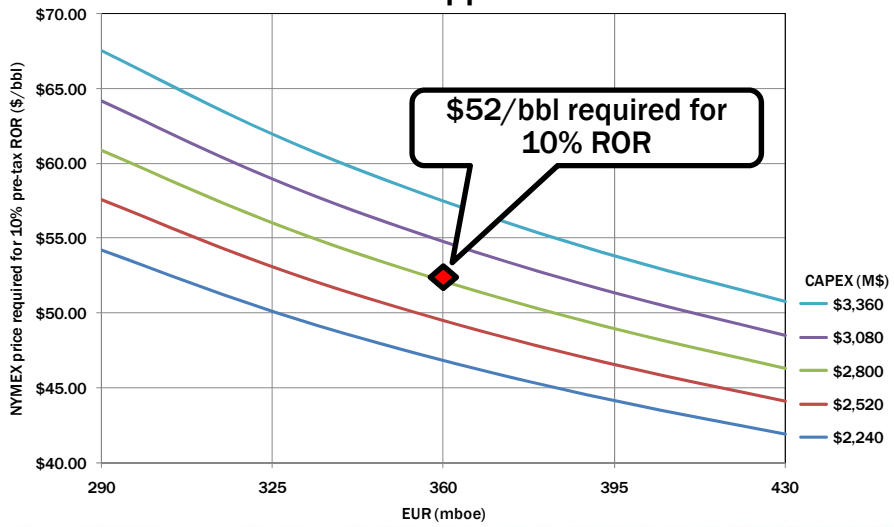
Texas Panhandle Granite Wash



Cleveland/Tonkawa



Mississippian

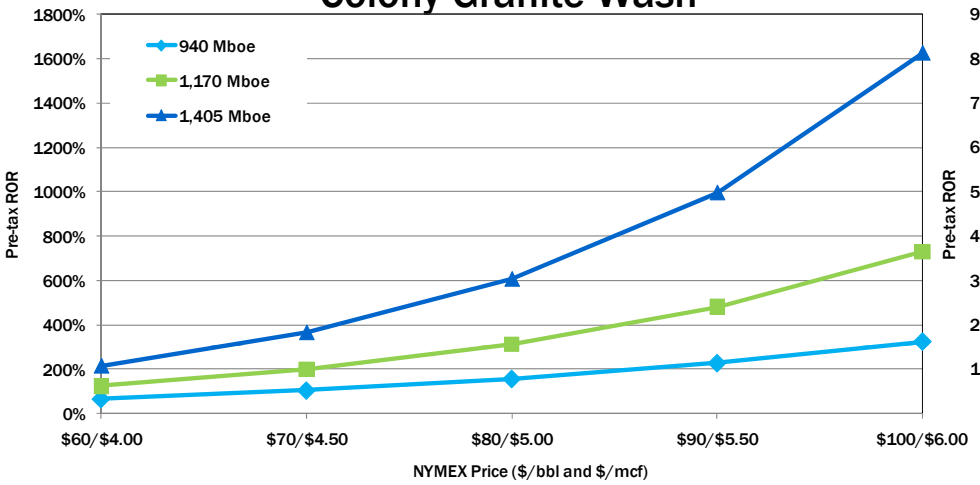


Note: assumes natural gas prices of $5.00/mcf

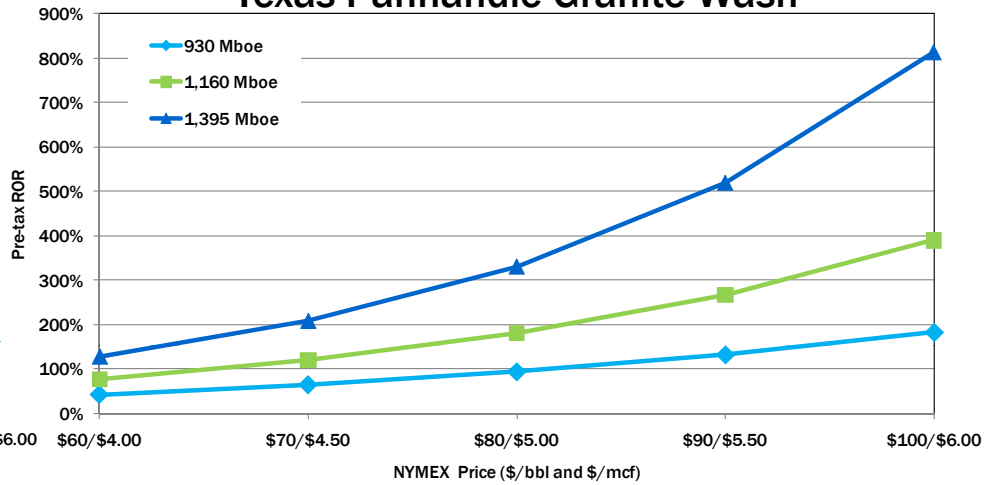
Type curve

Anadarko Basin – Rate of Return Profiles

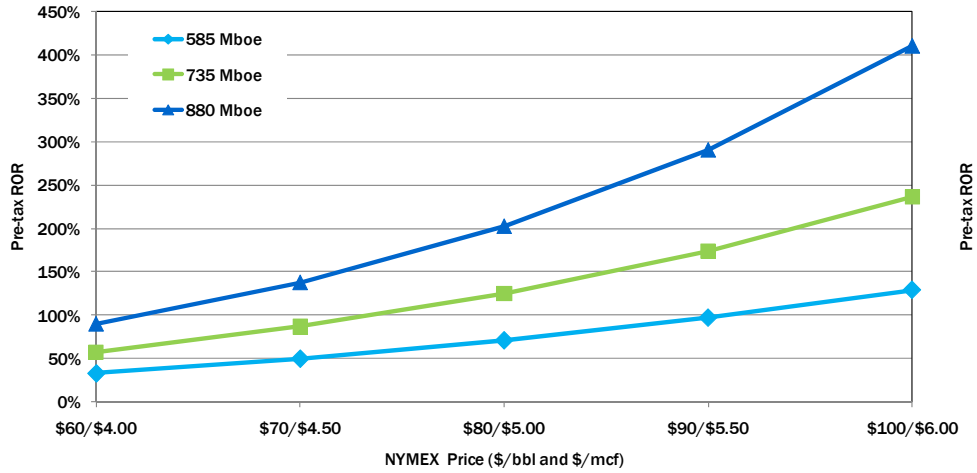
Colony Granite Wash



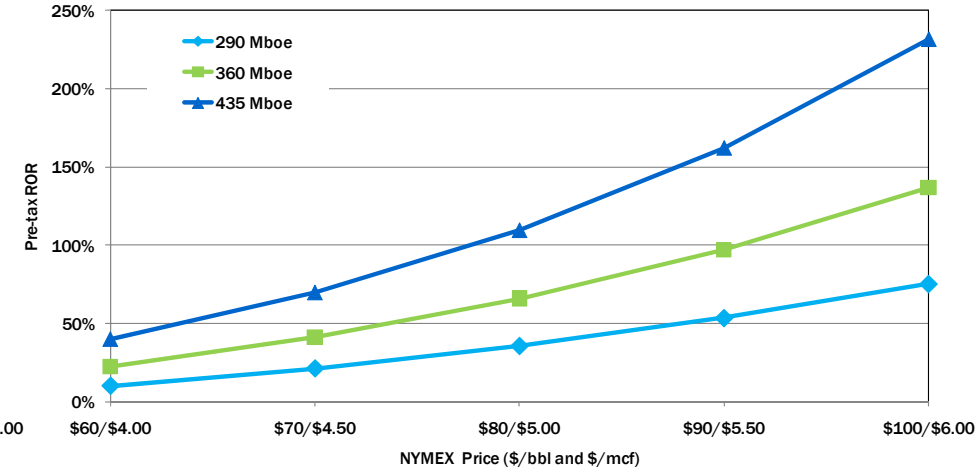
Texas Panhandle Granite Wash



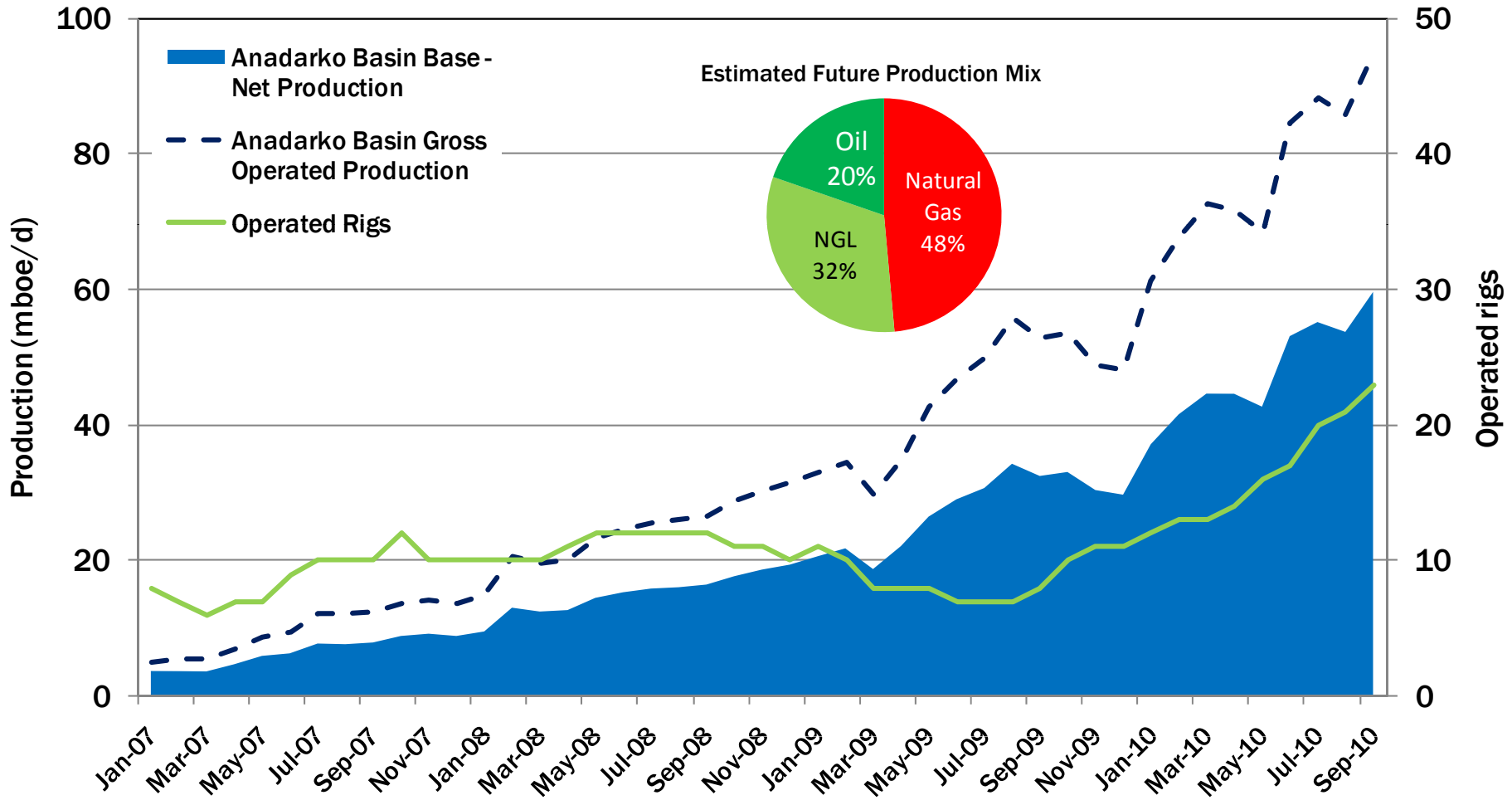
Cleveland/Tonkawa



Mississippian



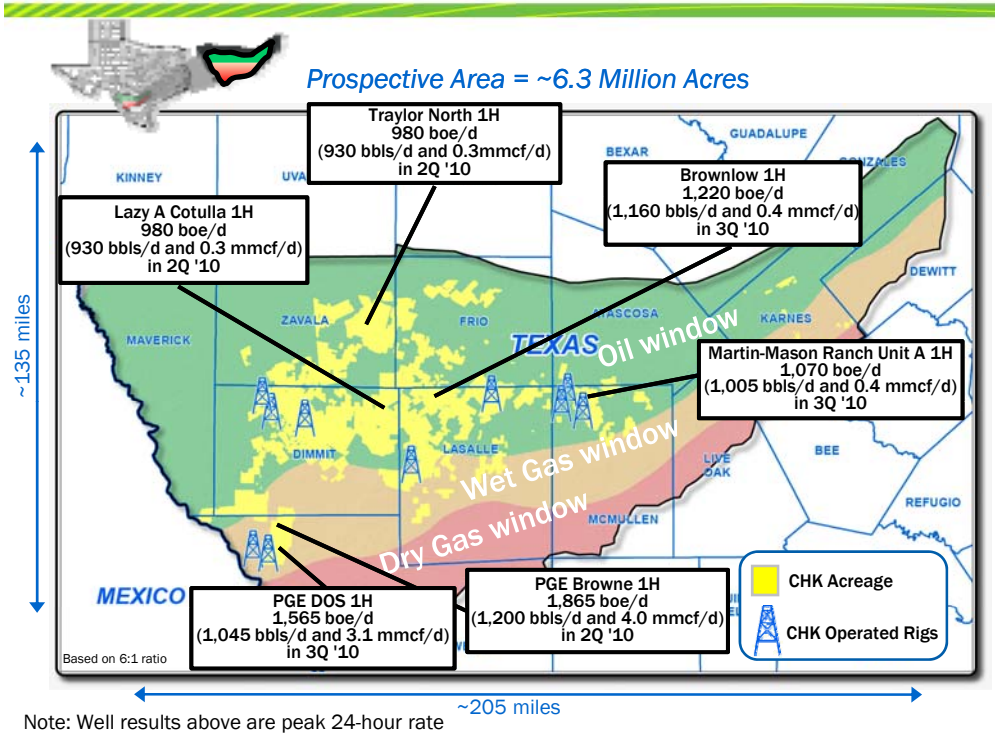
Anadarko Basin – Production Profile & Rig Count



Eagle Ford Shale Play

Skye Callantine, Geoscience Manager - South Texas District

Eagle Ford Shale – Overview



Note: Well results above are peak 24-hour rate

- **World-class liquids-rich play**
  - ~3.5 billion boe unrisked unproved resources net to CHK in the Eagle Ford Shale
  - Substantial additional upside potential in the deeper Pearsall formation

- **The Eagle Ford Shale is quickly developing into the most profitable of all shale plays**
- **CHK began leasing in August 2009 and has since captured the largest position in the industry with ~625,000 net acres**
  - Focused leasehold position in oil and wet gas windows and within areas that have optimal mix of permeability and thermal maturity
- **Very attractive rates of return**
  - Relatively shallow formation results in low drilling and completion costs
  - High value production from oil and wet gas
- **Currently have 10 horizontal wells on production**
- **Currently operating 10 rigs in the play and plan to drill ~65 gross wells in 2010**
- **Plan to exit 2012 with ~40 rigs**
- **New JV with CNOOC (NYSE: CEO)**

The Eagle Ford will quickly become a key component of CHK's liquids production

CHK/CNOOC Eagle Ford Shale Joint Venture Summary

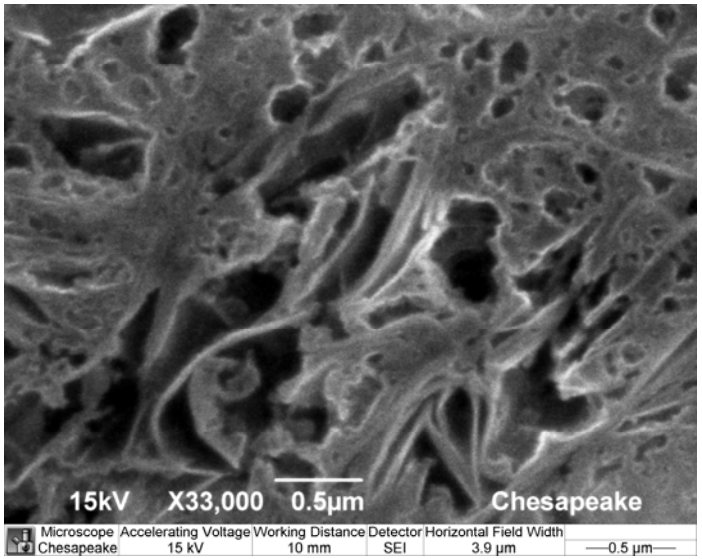
- **CHK has sold a 33.3% interest in 600,000 net acres in the Eagle Ford Shale to CNOOC International Limited for $2.16 billion or $10,800 per net acre, on a 50/50 cash/carry basis; an additional 25,000 acres to be offered after closing**
- **CNOOC will pay $1.08 billion in cash at closing and will pay an additional $1.08 billion by funding 75% of CHK's share of drilling and completion expenditures until the $1.08 billion carry obligation has been funded**
  - Closing of the transaction is anticipated in 4Q '10
  - CHK expects to utilize the drilling carry by YE 2012
- **CHK will serve as the operator of the JV and plans to continue acquiring leasehold in the Eagle Ford Shale**
  - CNOOC will have the option to acquire its 33.3% share of the new acreage on mutually attractive terms
  - CNOOC will also have the option to participate with CHK for a 33.3% interest in the development of midstream infrastructure in the Eagle Ford Shale

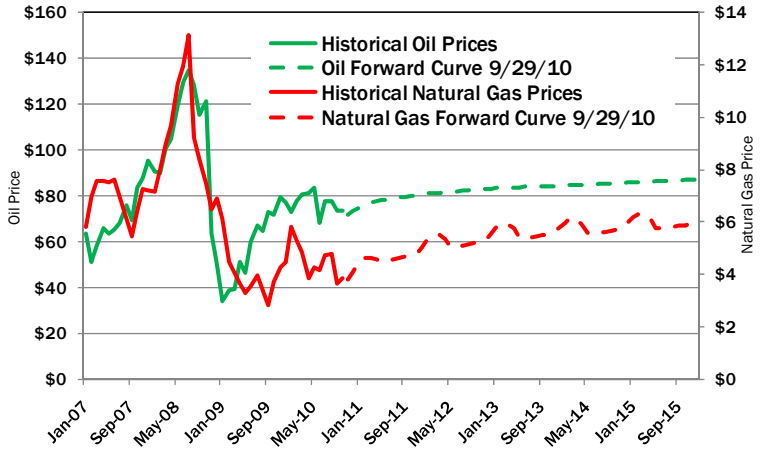
This JV values CHK's 625,000 net acres of leasehold in the Eagle Ford Shale at $6.75 billion

Why Did CHK Target the Eagle Ford?

- CHK pursues all unconventional plays that it believes will work – we have only missed the Bakken so far
- CHK is shifting its focus to liquids and decided not to play the down-dip dry gas portion of the Eagle Ford
- Value of liquids is 3x more valuable than natural gas on a BTU basis, so CHK targeted the wet gas and oil portions of the Eagle Ford
- BTU value greater than any other shale play, therefore, CHK expects the Eagle Ford to be the most profitable U.S. shale play
- Great oil-in-place: ~50 mmbbls/section
- Optimal thermal maturity
- Best rock properties
- Big ranch country and, therefore, small number of leases does not require drilling to become as frenzied as in other shale plays
- Good gas gathering and processing infrastructure nearby

Microscopic image from CRTC





What Makes the Eagle Ford Shale Special?

- **Great returns**
  - >80% of revenue from liquids, reducing dependence on natural gas price
  - Only 8% recovery of oil-in-place modeled – significant upside for improved performance
- **Shallower depth (compared to other shale plays) keeps costs down and reduces cycle time**
- **Adequate formation pressure and drive**
- **Manageable stimulation pressure minimizes service equipment wear and keeps costs lower**
- **Large tracts**
  - Average leases contain ~350 net acres compared to 1.3 and 14 net acres in the Barnett and Haynesville, respectively
  - Rural – less than 1% in incorporated cities
- **In an established producing state with defined procedures, regulatory bodies and midstream access**
- **Easily managed from OKC headquarters**

Eagle Ford Shale is a foundational asset for CHK's focus shift to liquids-rich plays

Eagle Ford Operations – Accelerating The Learning Curve

- **Rapidly transferred and fully integrated lessons from other unconventional plays within CHK**
- **Numerous technical discussions and idea sharing with other Eagle Ford operators**
- **Previous shale experience led to immediate drilling of long laterals**
  - On only its third well, CHK set a new record for lateral length for an Eagle Ford well
- **Employed Chesapeake Reservoir Technology Center (CRTC) and petrophysical expertise to better understand rock mechanics and completion parameters**
  - Utilized rock mechanical data and performed numerous frac simulations to better understand frac geometries
  - Based on experience in other unconventional liquid-rich plays, immediately utilized tighter perforation cluster spacing, greater number of stages and optimized fracture conductivity
- **Well performance supporting design criteria**

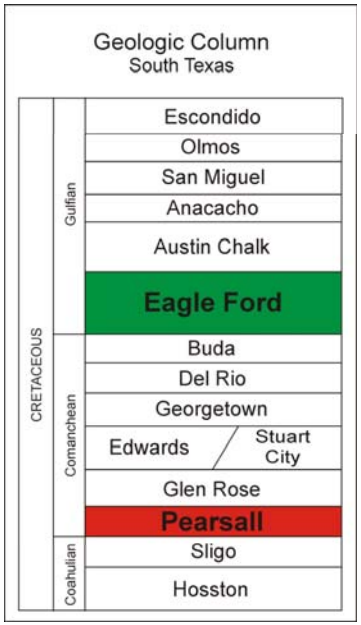
Leveraging knowledge from most active drilling program in America has quickly made CHK a top-tier operator in the Eagle Ford

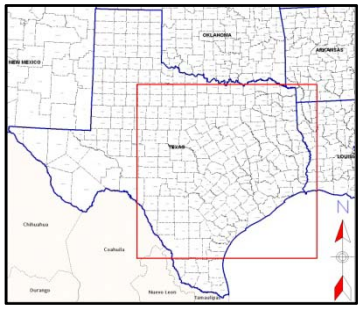
Competitive Advantage – Technology

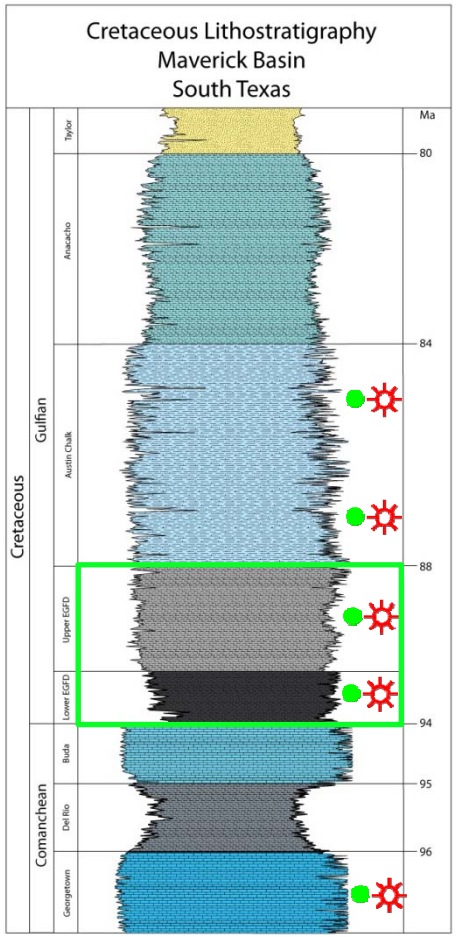
- **CHK's comprehensive reservoir characterization drives the Eagle Ford development**
  - Maximize value by increasing recovery factor at lower costs
- **Industry-leading subsurface technical team has transferred focus to development optimization**
  - Vertical placement of laterals
  - Stimulation techniques
  - Drilling efficiencies
  - Well spacing
- **CHK's commitment to technology exemplified by its aggressive subsurface data acquisition program**
  - 10 cored wells (~2,800') with full open-hole log suites
  - >4,500 linear miles of 2D seismic and 830 square miles of 3D seismic with an additional 1,000 square miles of 3D seismic being acquired
  - Several micro-seismic tests planned
    - Downhole monitoring
    - CHK's first buried array allowing monitoring of many wells over several years with same geophones

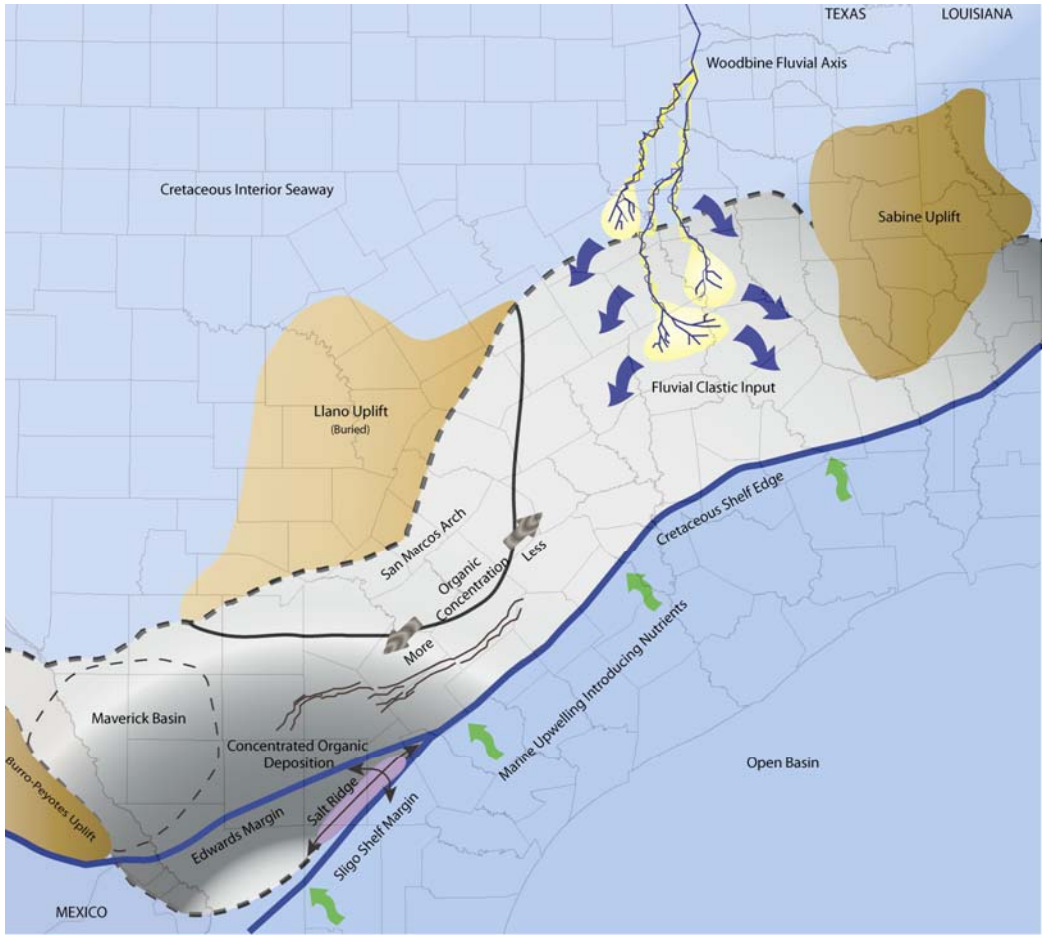
Aggressive information gathering in Eagle Ford combined with leading technological position in most U.S. oil and gas shales will make CHK the most efficient developer of Eagle Ford acreage

Eagle Ford Shale – Geology



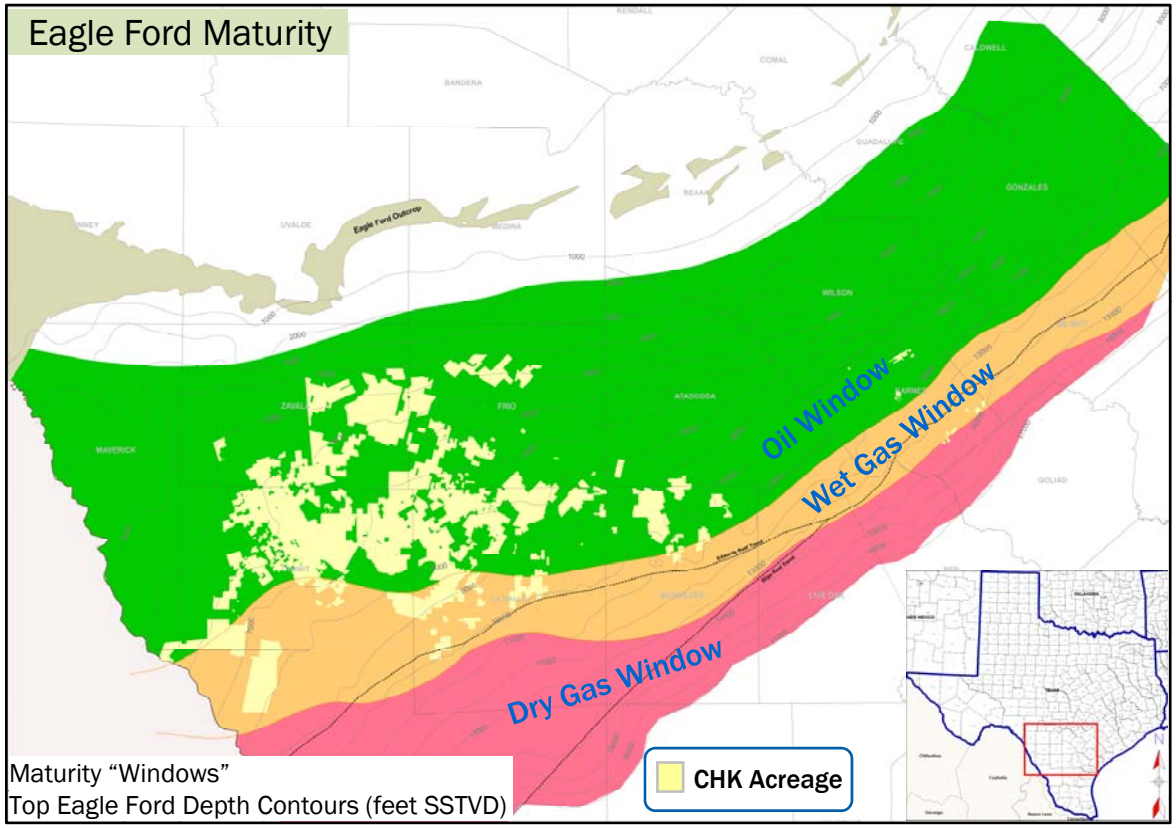






During Eagle Ford geologic time, the environment in South Texas was superior to the rest of the Gulf Coast for deposition and preservation of organic shale

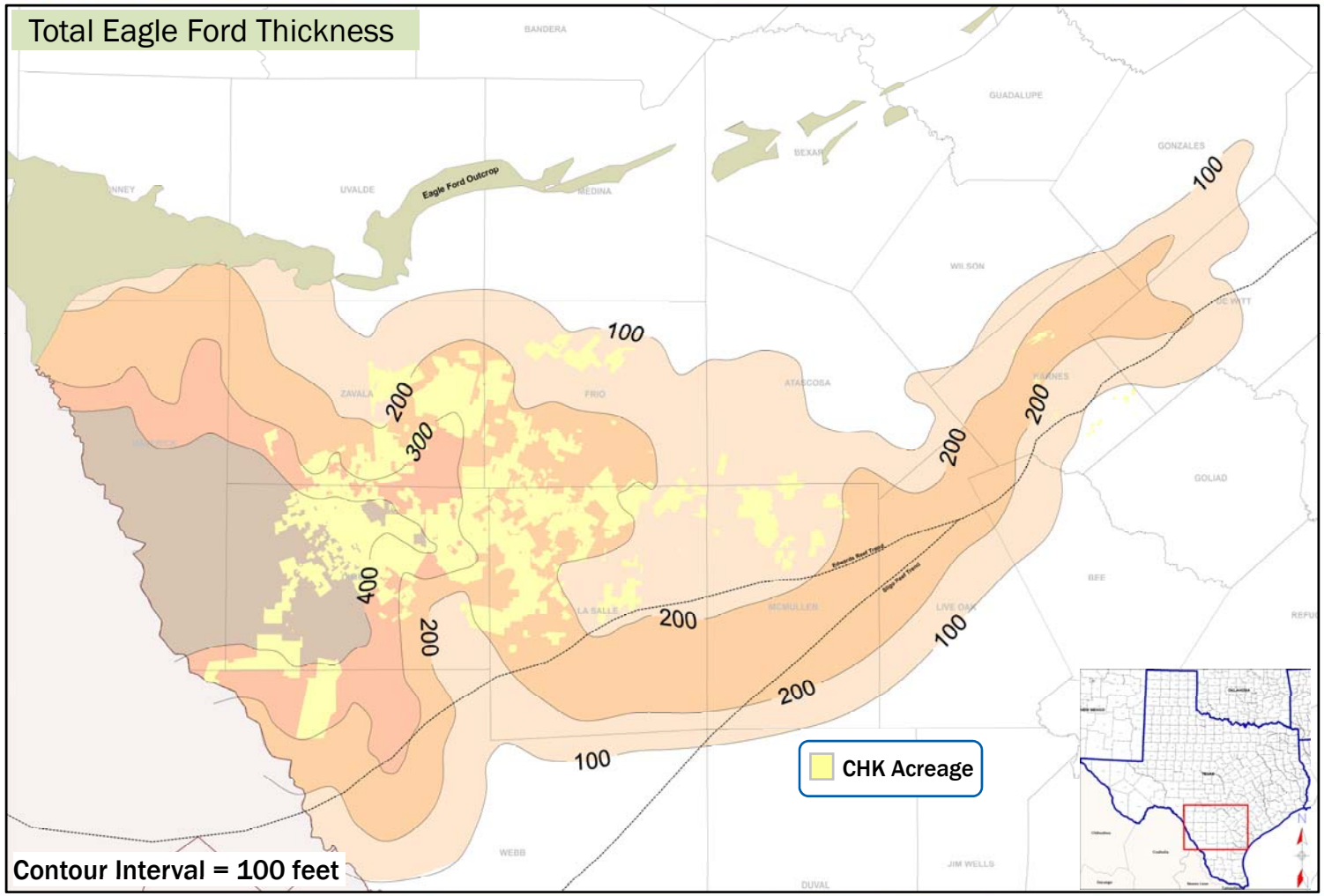
Eagle Ford Maturity



- **CHK targeted acreage with:**
  - Maturity between peak oil and wet gas windows
  - Thick Eagle Ford section
  - High oil in place
  - Excellent porosity and permeability
  - Adequate reservoir pressure
- **~2,800 feet of analysis core and >200 petrophysical control points confirm reservoir quality**

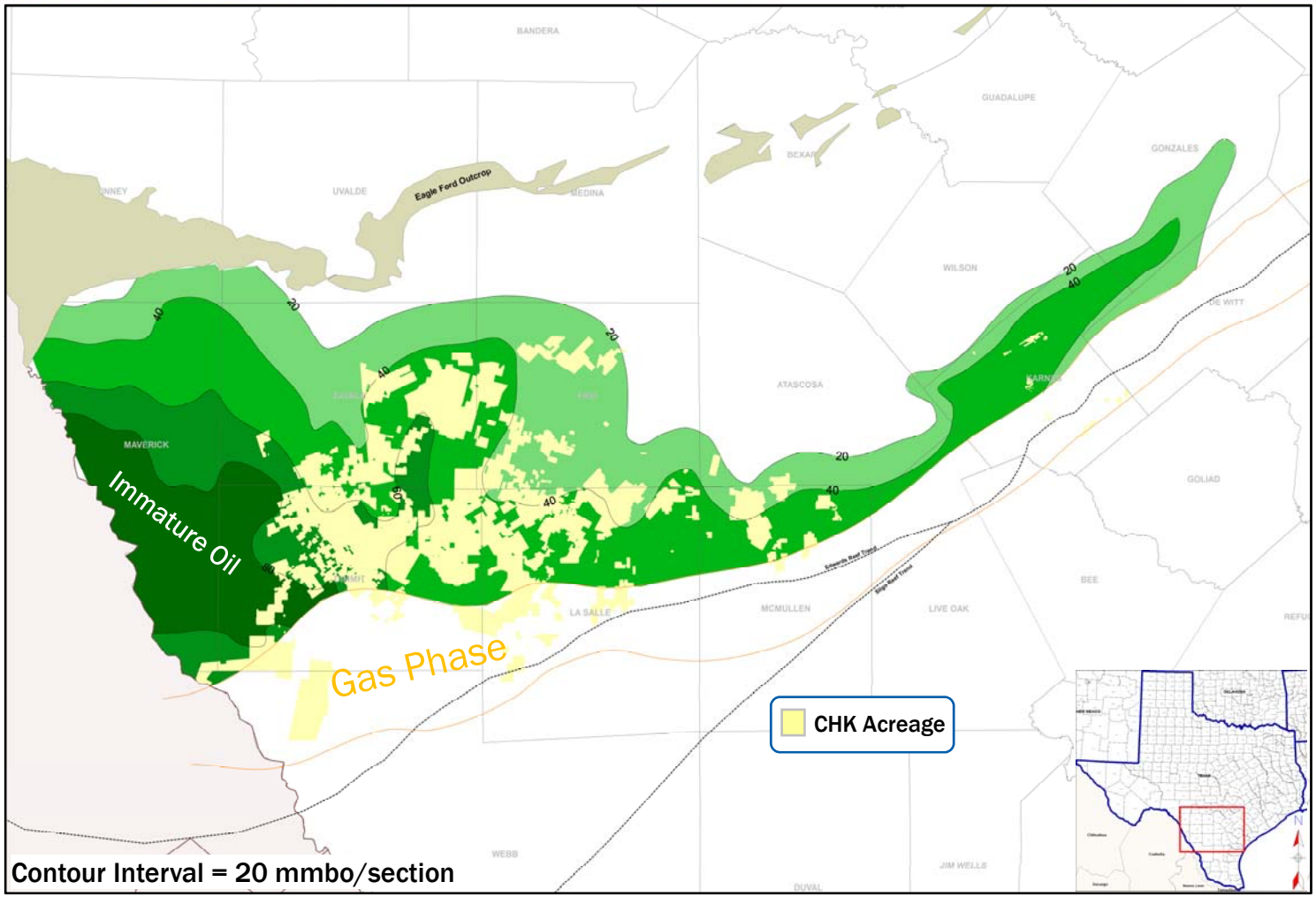
CHK acreage is optimally located within the peak oil and wet gas maturity windows

Eagle Ford Isopach



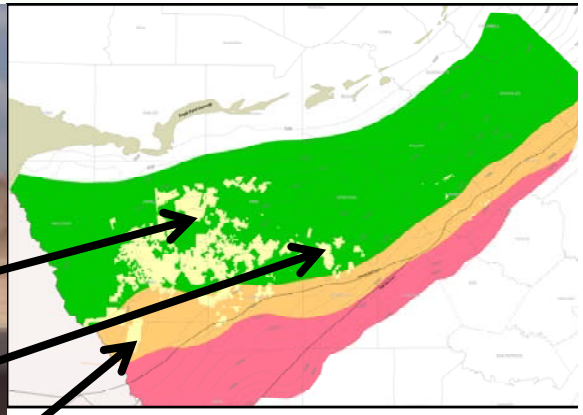
CHK acreage is concentrated on the edge of the Maverick Basin where a very thick section of organic shale was deposited

Eagle Ford Oil in Place



CHK acreage has excellent oil in place (thickness and porosity), allowing for tremendous upside with continuously improving recovery factor

Eagle Ford Oil Specs

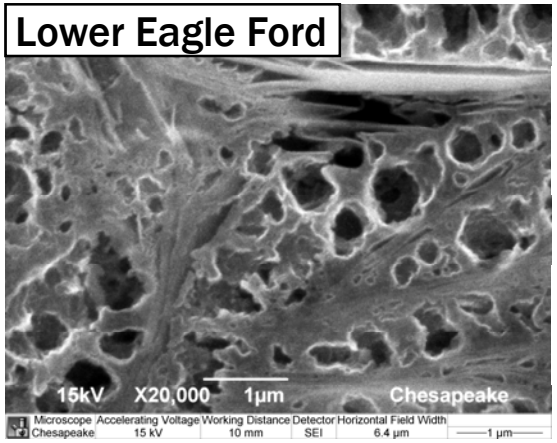


- **Black oil to condensate**
  - API gravity trending higher
  - Oil viscosity trending lower
  - Solution GOR trending higher

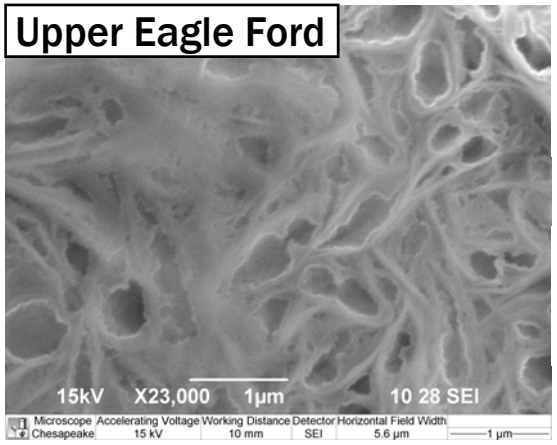
Eagle Ford Shale – Characteristics

Microscopic images from CRTC

Lower Eagle Ford



Upper Eagle Ford



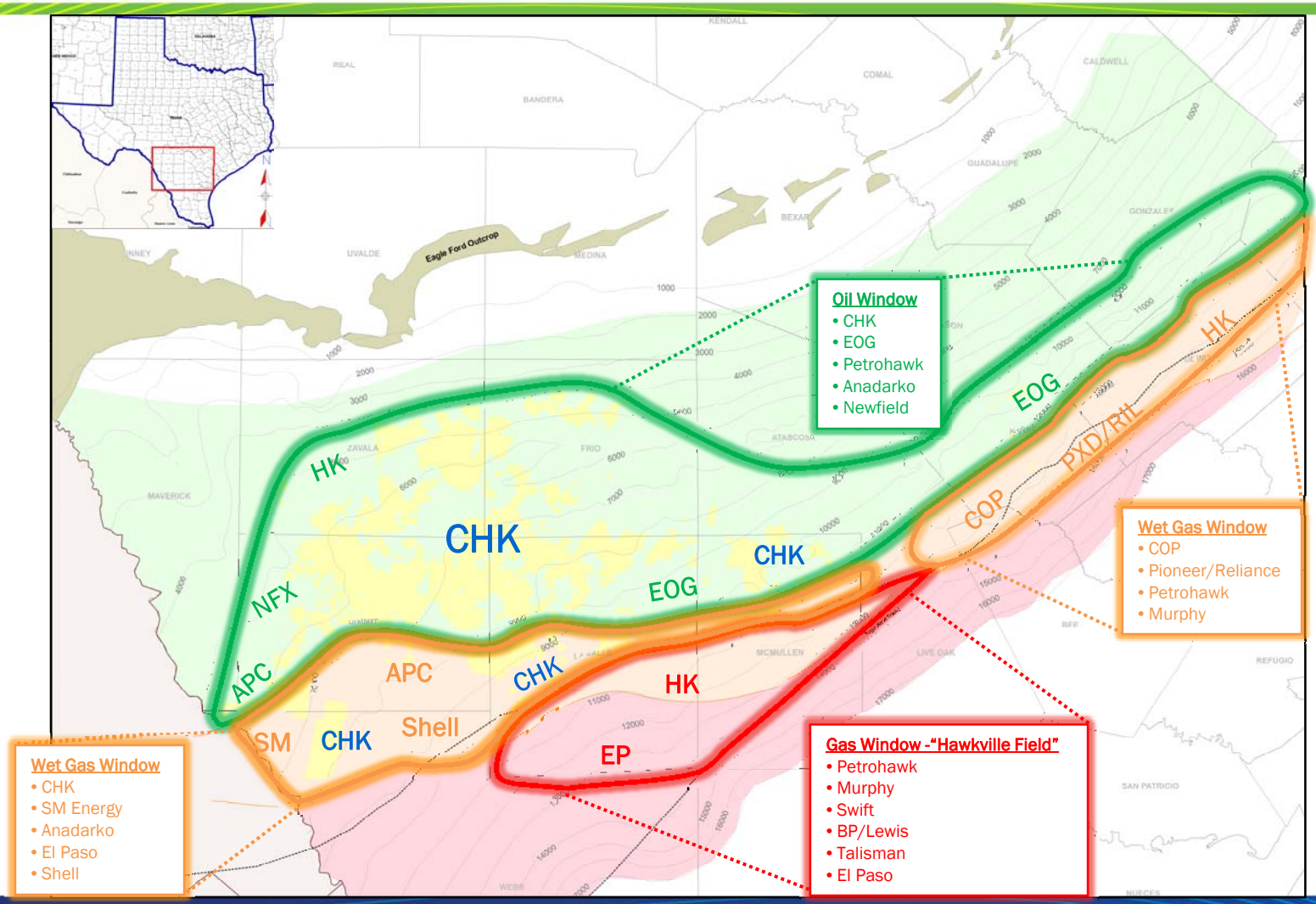
Porosity is distributed between intergranular and intrakerogen

Depth TVD (feet)	5,000 – 11,500
Well total depth (feet)	10,000 – 17,500
Net thickness (feet)	140 – 450
Total organic content (TOC)	3% – 7%
Log porosity	6% – 9%
Permeability (nD)	700 – 3000
Pressure gradient (psi/foot)	0.4 – 0.7
Water saturation	13% – 25%
Average lateral length (feet)	5,000 – 8,000
Oil-in-place/section (mmbo/section)	40 – 70
Gas-in-place/section (bcf/section)	140 – 150
Anticipated recovery factor – oil	6% – 10%
Anticipated recovery factor – wet gas	30% – 40%
Average EUR/horizontal well (mboe)	595

- Blend of oil and wet gas

Eagle Ford Shale has some of the best rock properties of all U.S. shale plays

Eagle Ford Shale Industry Activity



CHK & EOG are the primary players in the oil window

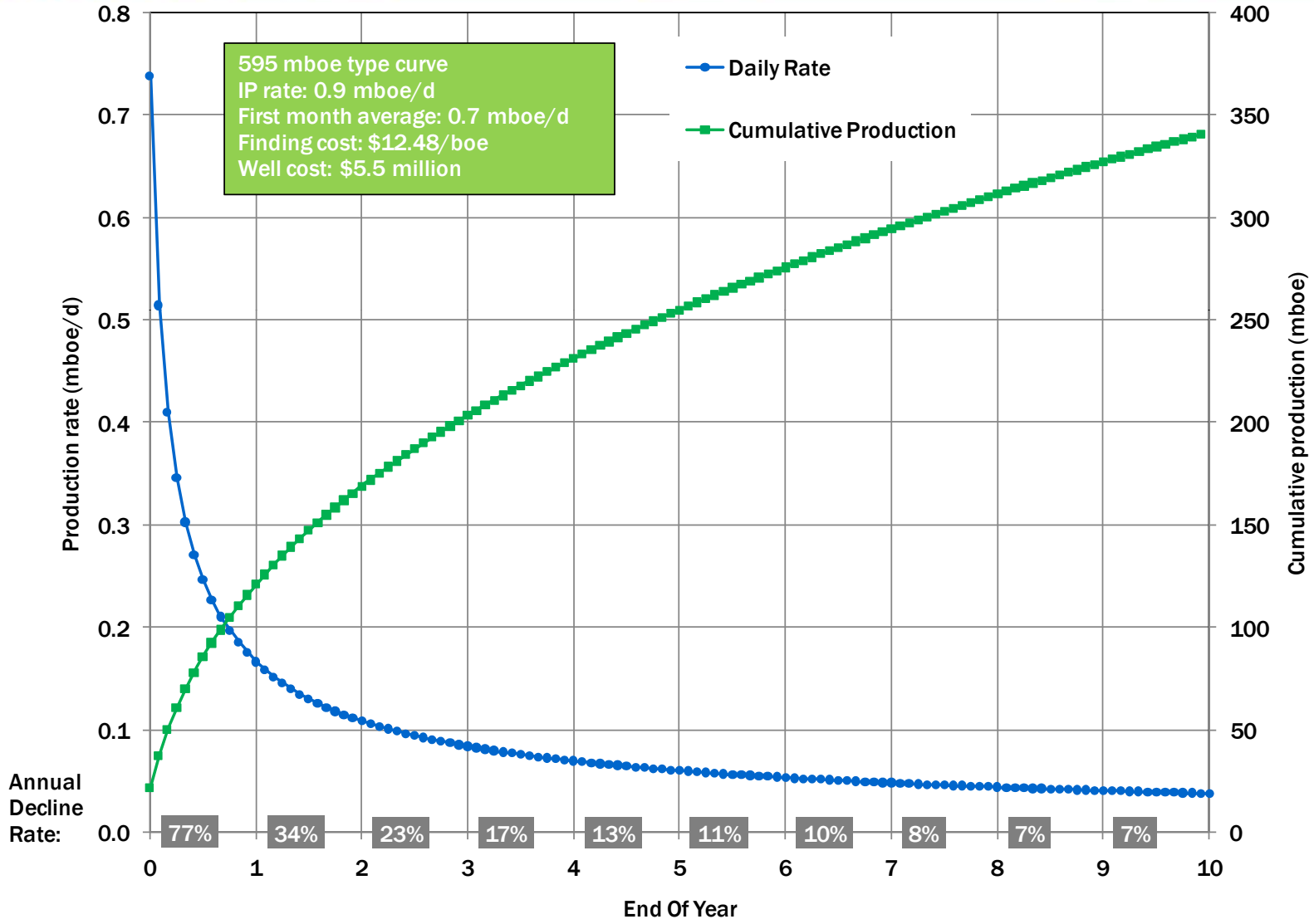
Eagle Ford Shale – Development Plan

- CHK leasehold of ~625,000 net acres
  - ~600,000 net acres initially part of 67/33 JV with CEO
- 8 - 10 wells from single surface pad
- Lateral length: 5000' - 8000'
- Nominal spacing: 500' - 660' between wells
- Targeted EUR
  - 595 mboe (blended oil and wet gas)
- Drilling and completion costs of ~$5.5 mm per well
- Days to drill well (spud to spud): 20-24 days
- Total unrisked unproved resource potential: ~3.5 billion boe
- Average operated rig count:
  - Year-end 2010: 12 rigs
  - Year-end 2011: ~31 rigs
  - Year-end 2012: ~40 rigs

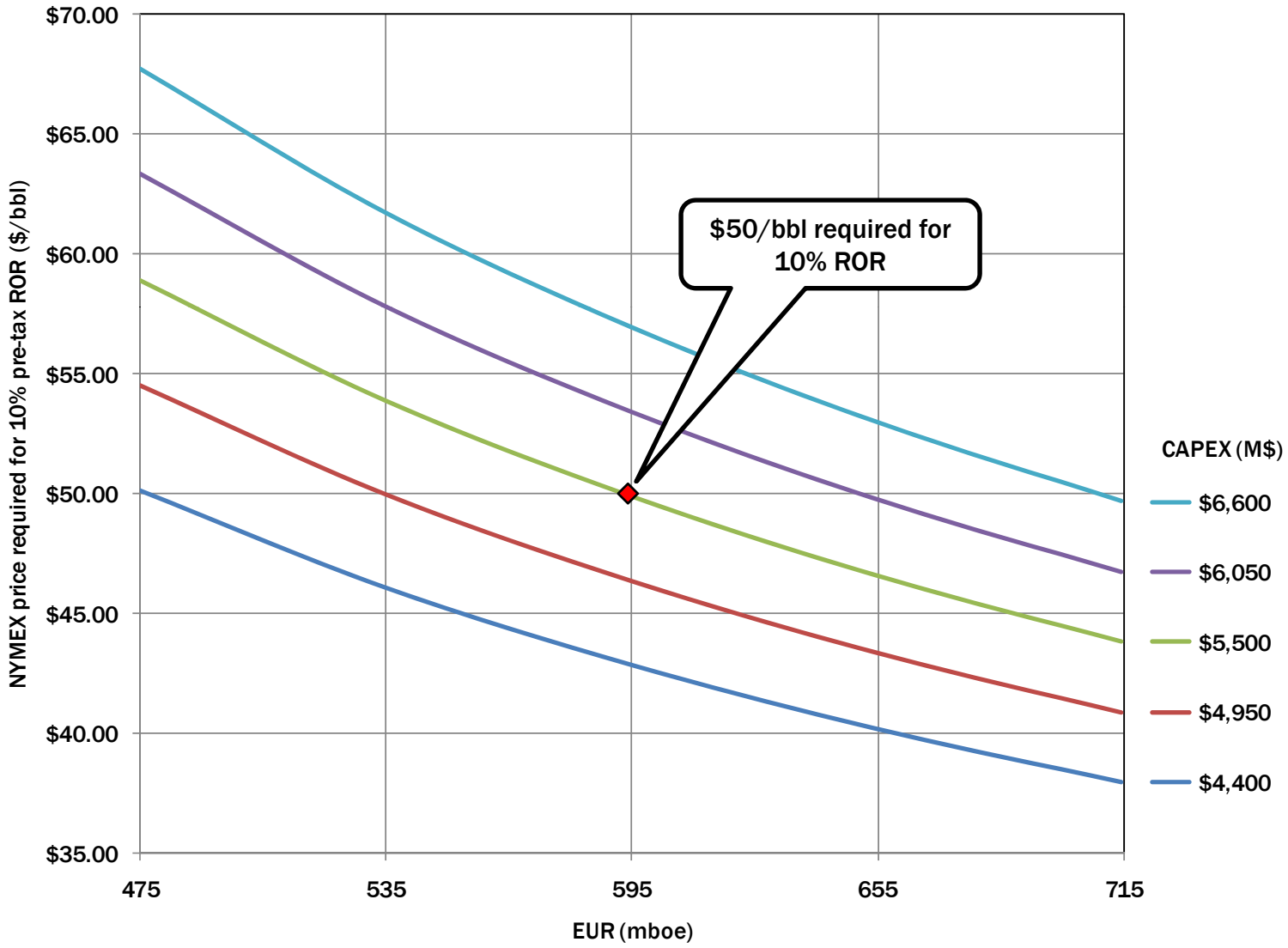
Note: resource potential assumes 80-acre spacing

Unparalleled growth plan in the Eagle Ford

Eagle Ford Shale – Targeted Well Profile

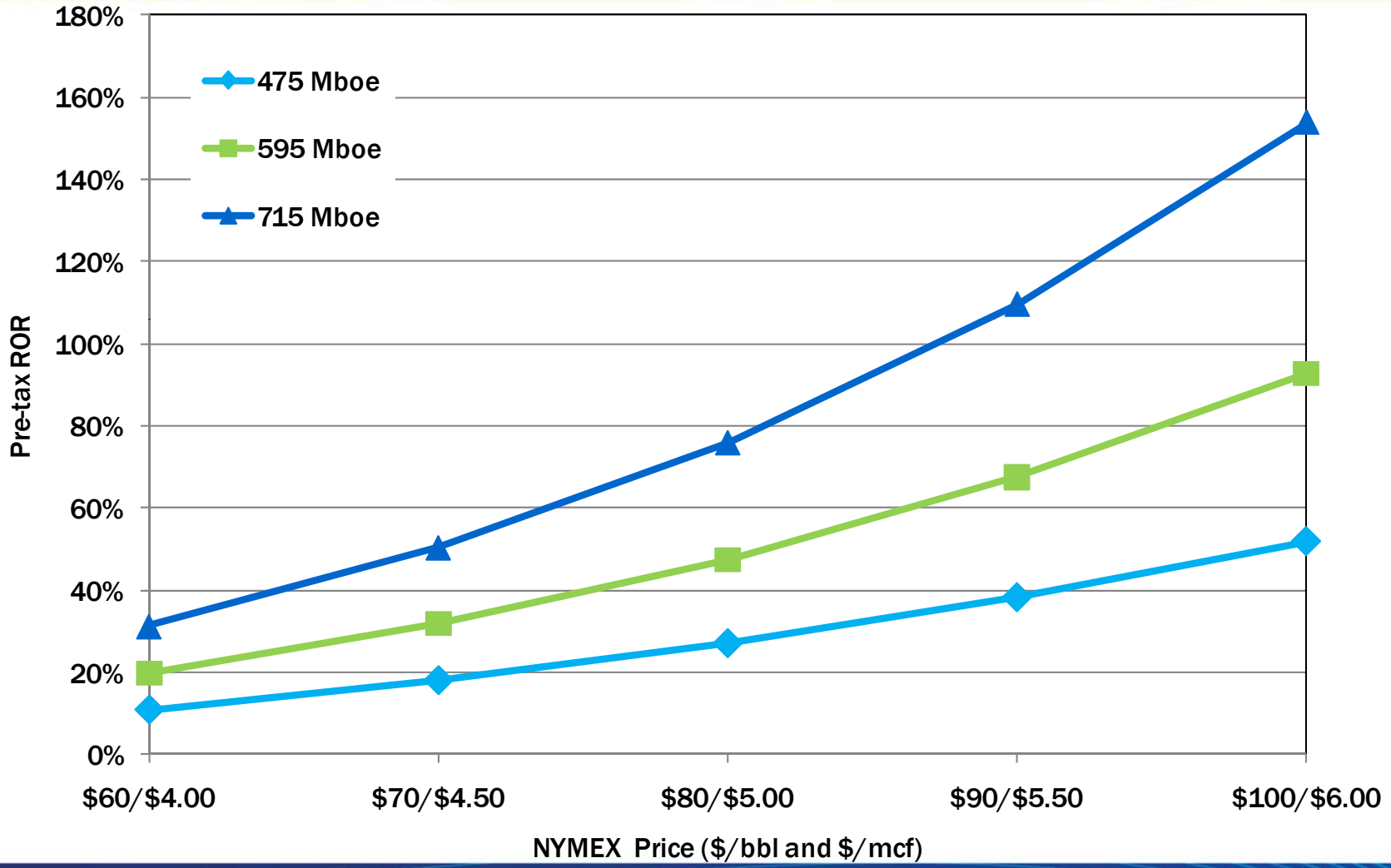


Eagle Ford Shale – PV10 Sensitivity



Note: assumes natural gas price at $5.00/mcf
◆ Type curve

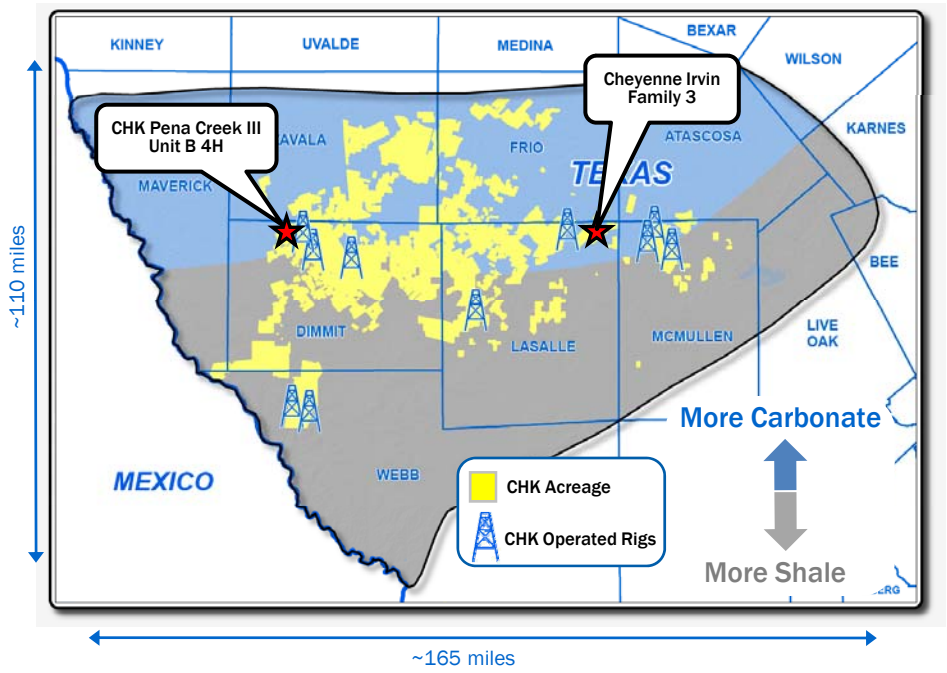
Eagle Ford Shale – Rate of Return Profile



Oil window >90% of revenue from liquids

Wet gas window >70% of revenue from liquids

Pearsall Shale – Overview



- The Pearsall Shale holds a tremendous upside across much of CHK Eagle Ford acreage
- CHK leasehold of ~345,000 net acres prospective; one of the biggest Pearsall position in the industry
- Interbedded organic shale and limestone
- Industry activity has proven the Pearsall Shale formation to be productive in CHK core area
- Currently drilling and coring first CHK operated Pearsall well
  - Participating in 1 non-operated well
  - Additional wells planned to further delineate productivity on CHK acreage
- Pearsall and Eagle Ford plays are stacked
  - Cost savings and efficiencies on shared surface facilities

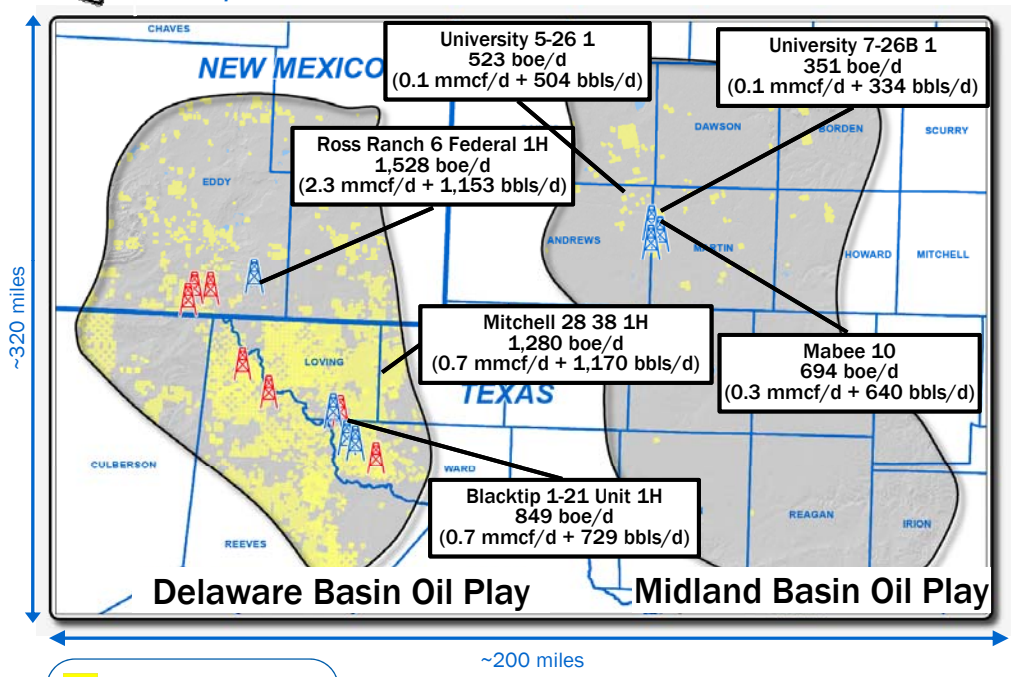
CHK has the largest combined resource potential in the Eagle Ford and Pearsall Shales

Permian and Rockies Plays

Steve Dixon, EVP – Operations and COO

Permian Basin – Overview

Prospective area = ~4.5 mm acres in DB and ~5.9 mm acres in MB

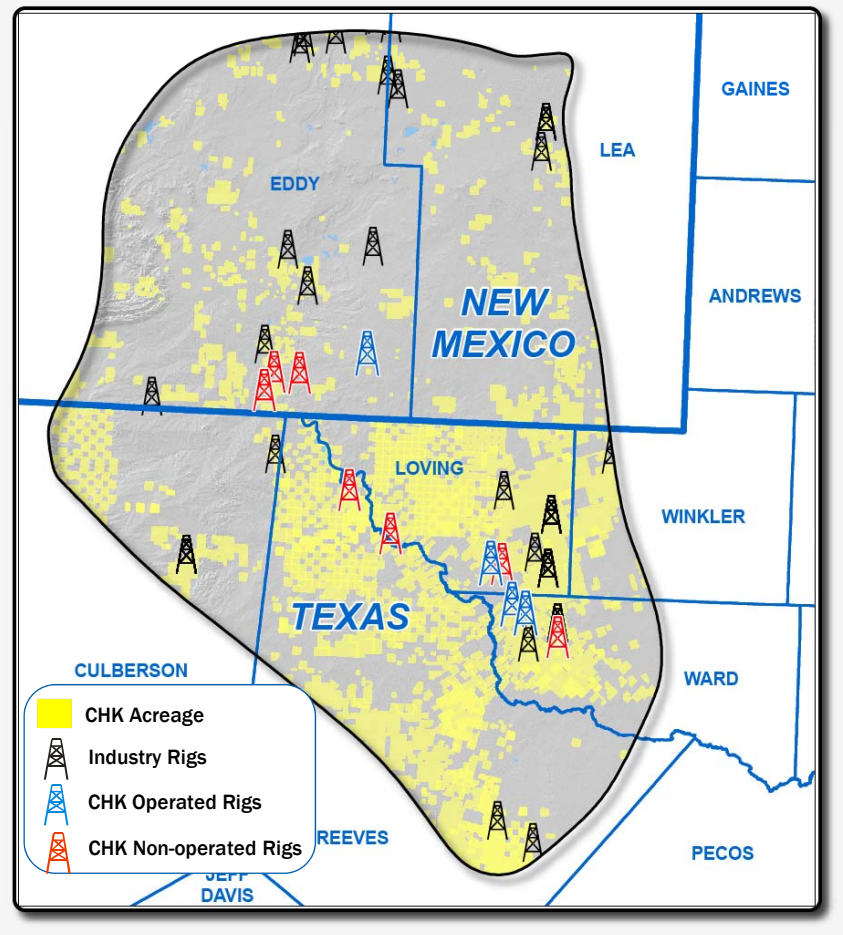


Note: Well results above are peak 24-hour rate

- In the Permian Basin, CHK historically has focused on drilling vertically for natural gas in the Deep Haley play and both vertically and horizontally for natural gas in the Delaware Shale plays
- Strong oil prices, advances in drilling and completion techniques and advanced analysis has shifted CHK's focus to horizontal Delaware Basin (DB) plays and vertical Midland Basin (MB)plays
- CHK drilled its first Bone Spring horizontal well in 2006 and the industry's first Avalon Shale well in 4Q '08
- CHK's combined leasehold for unconventional Permian Basin plays is ~615,000 net acres
  - ~570,000 in DB oil plays
  - ~45,000 in MB oil plays

CHK's Permian Basin assets provide abundant liquids-rich opportunities supported by well-established service industry and takeaway infrastructure

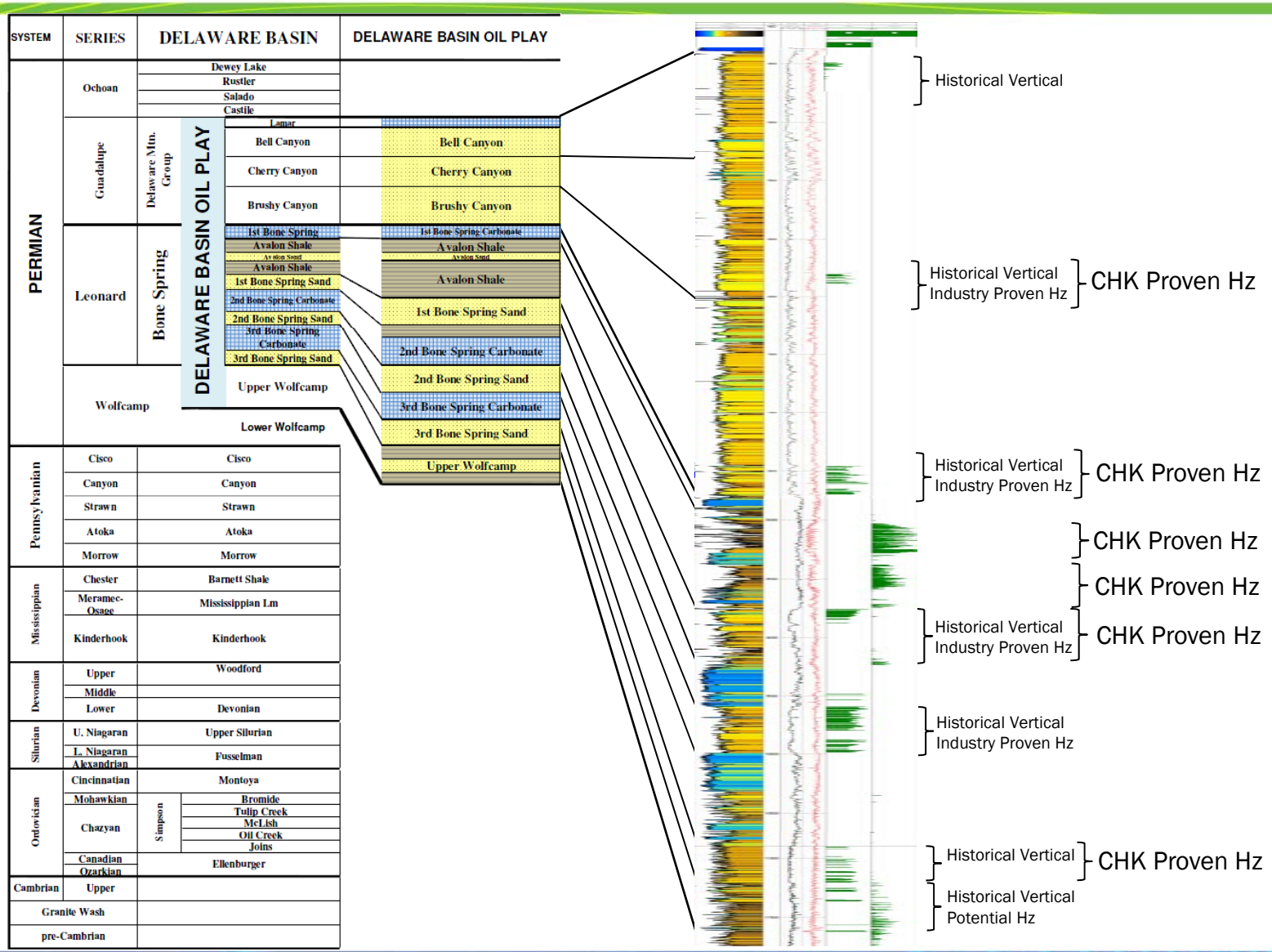
Delaware Basin Oil Play



- CHK operated and non-operated gross horizontal wells in the Delaware Basin oil play include:
  - ~105 horizontal producing wells
    - Delaware Sand
    - Avalon Shale
    - Bone Spring Sand
    - Wolfcamp
    - Barnett
    - Woodford
  - ~20 wells completing
- 4 operated and 7 non-operated rigs currently drilling
- Multiple wells with IP rates above 1,000 boe/d
- Average EUR's above 500 mboe
- Several organic rich formations with great rock properties all located in the oil window
- Very high oil-in-place

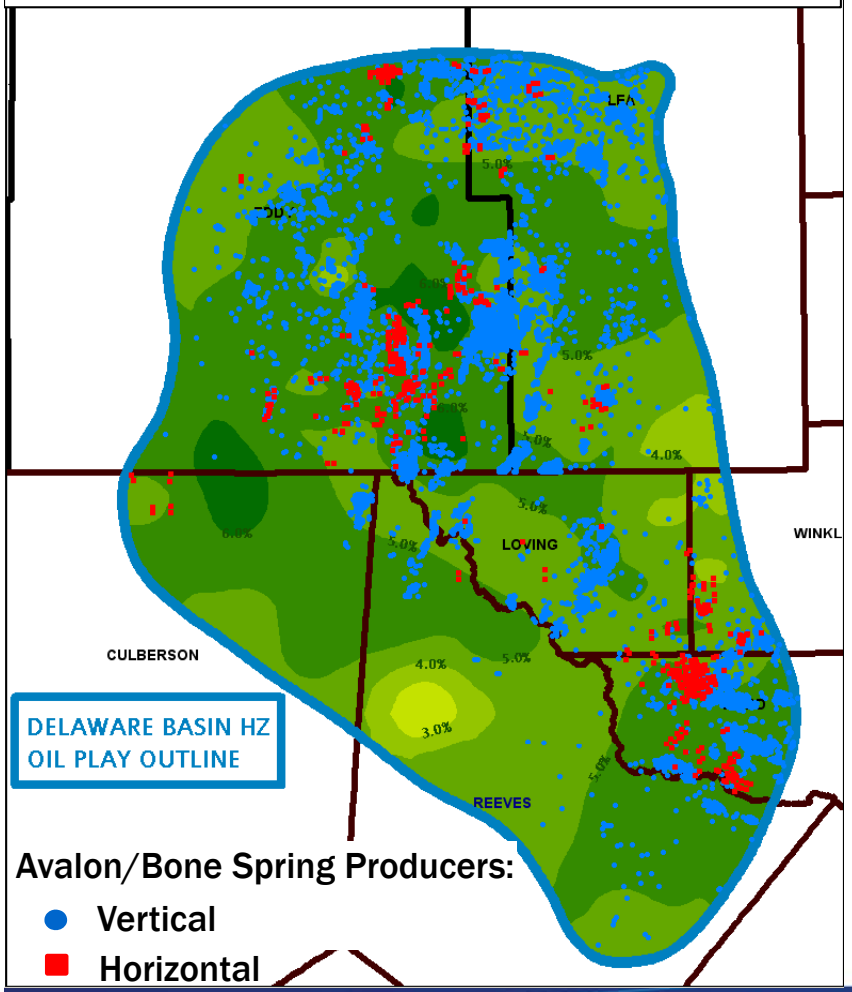
CHK has ~105 horizontal producing wells, or ~25%, of the industry's ~430 horizontal producing wells

Delaware Basin Oil Play



Delaware Basin Oil Play

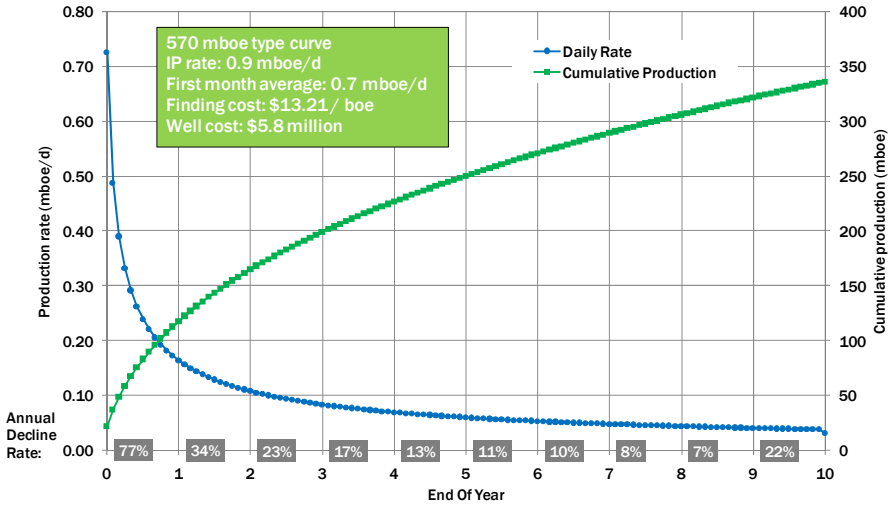
Isopach Color-fill of average TOC for Avalon Shale

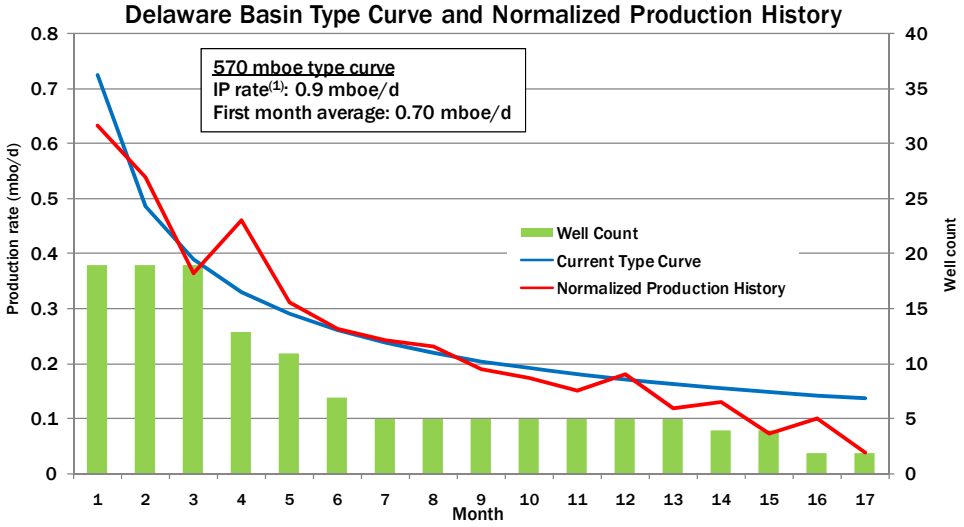


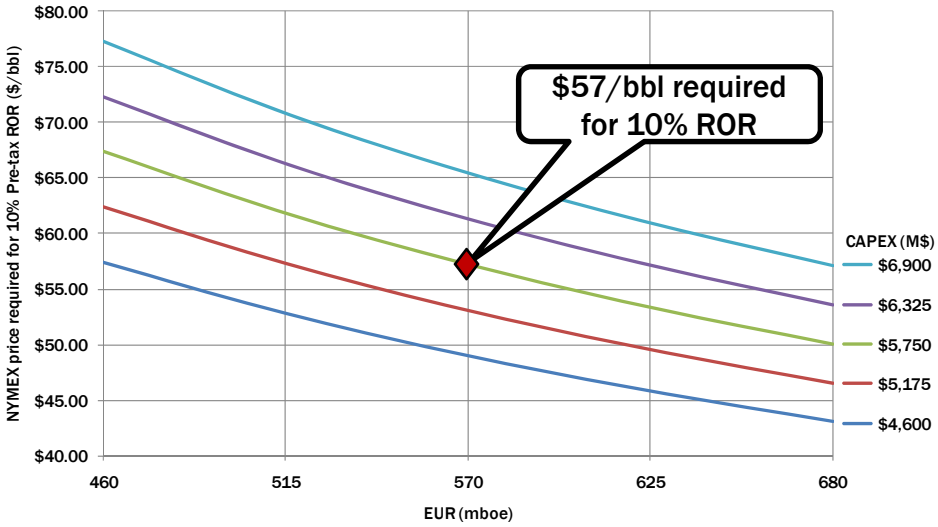
- **Oil-rich basin with:**
  - A thick sequence of basin-filling sedimentation composed of interbedded sandstones, siltstones, organic rich mudstones, non-organic shales, and detrital limestones and dolostones
  - Overall thickness ranges from less than 3,000’ to more than 4,500’
  - Structure which steeply dips along the basin margins becoming relatively consistent and uncomplicated as it dips into the basin axis west of the central basin platform
  - Actual drill depth (TVD of lateral) ranges from shallower than 6,000’ on the western flanks of the basin to below 12,000’ in the deepest portion of the play
  - Slightly over pressured in basin center

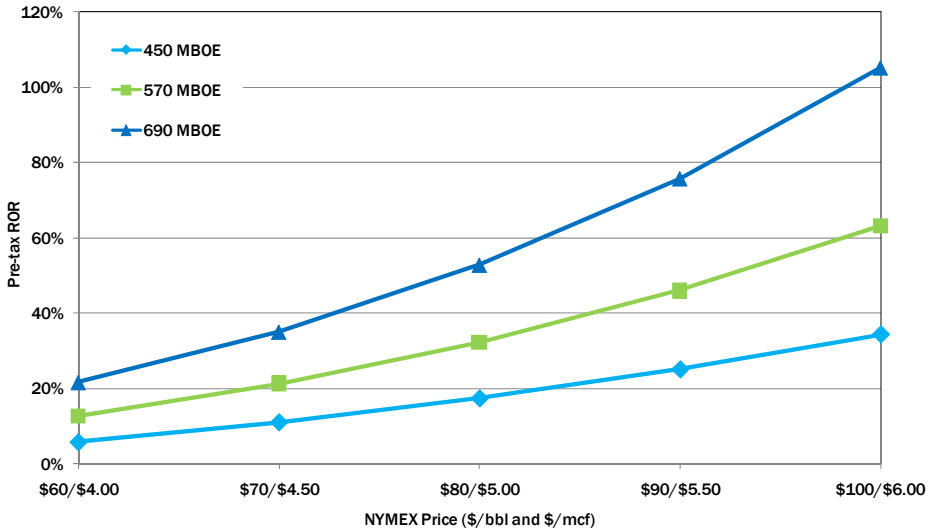
Perfect environment for exploiting multiple horizontal oil targets

Delaware Basin – Targeted Well Profiles and Economics



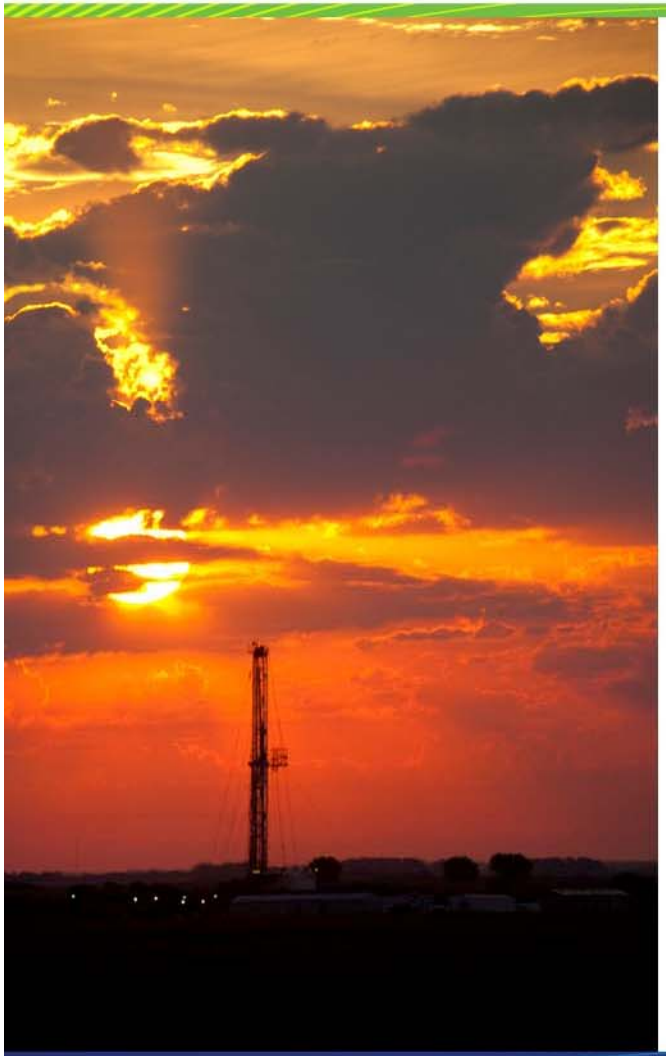




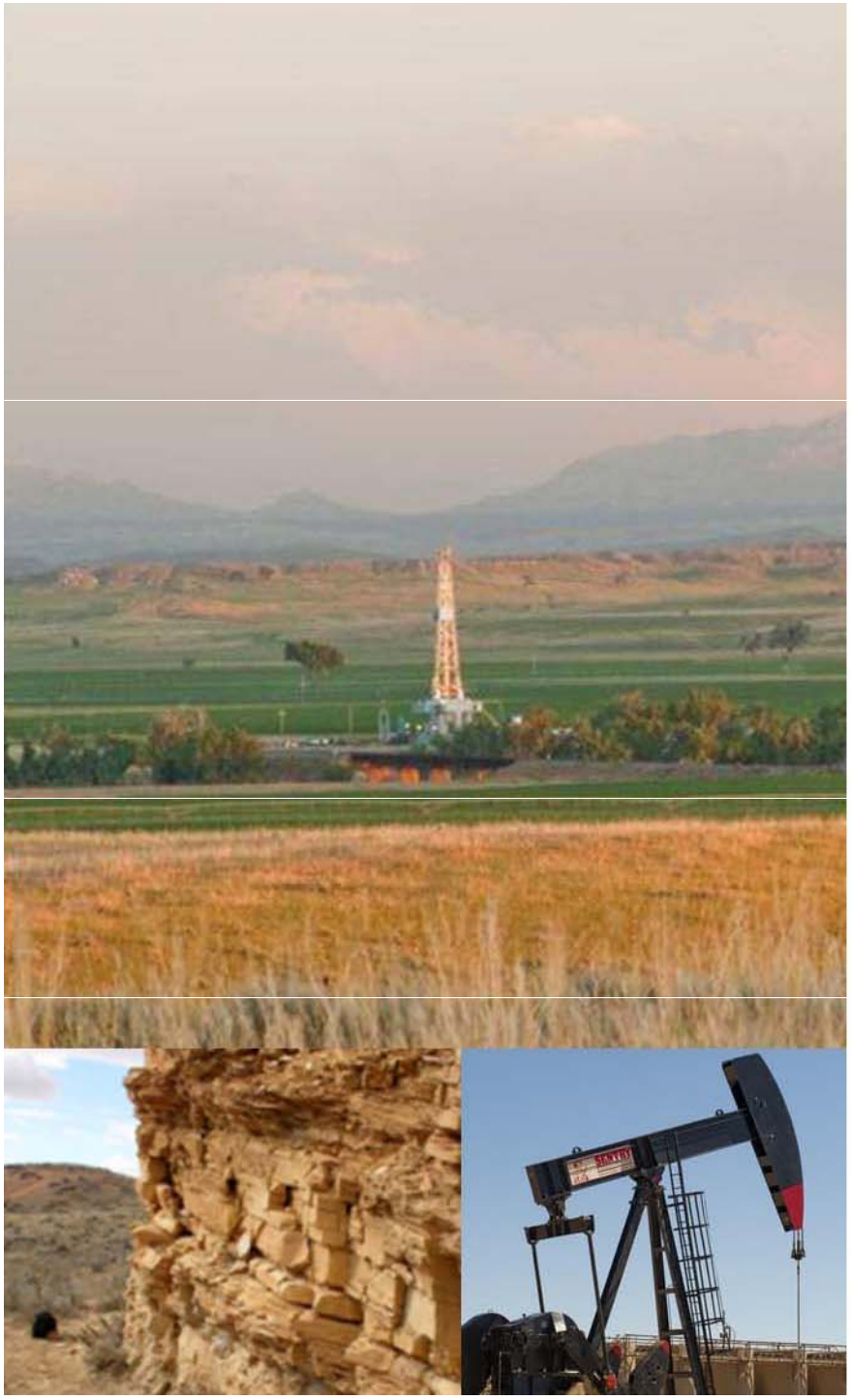


(1) Peak 24-hour rate
◆ Pro forma well

Permian Basin – Upside Opportunities

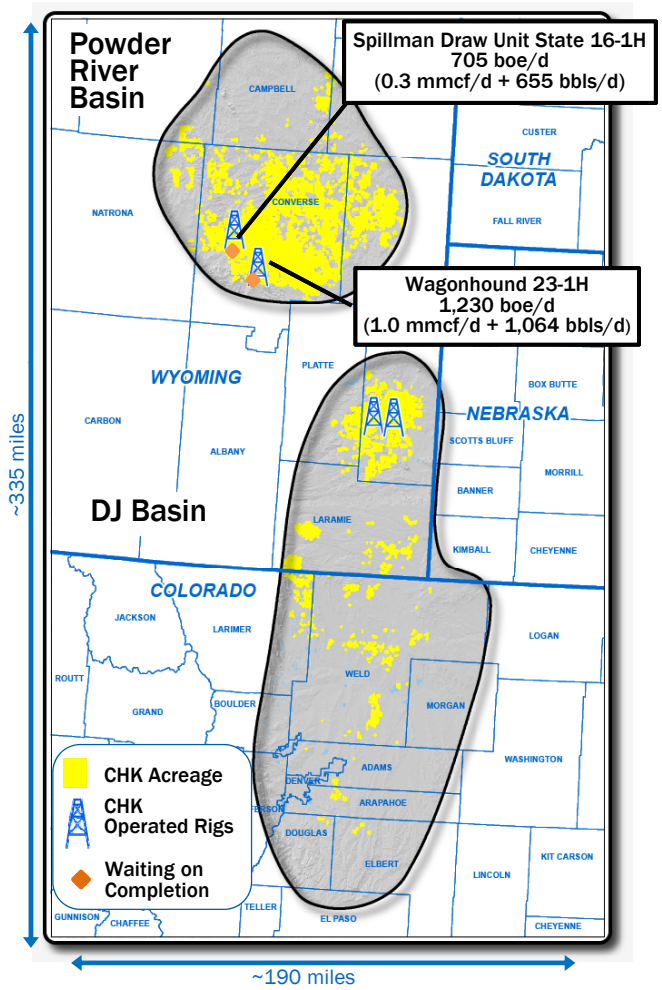


- Program drilling will decrease well costs
- Completion experience will improve reserves
- CHK has identified ~4,500 unrisked net undrilled wells
- CHK has potential unrisked unproved resources of ~1.7 Bboe
- Additional upside in stacked multi-lateral wells
- Over 11,000 square miles of 3D seismic
- Planning to average ~7 operated rigs in 2011
  - CHK's 615,000 net acres could accommodate much more



Rockies

Rockies – Overview

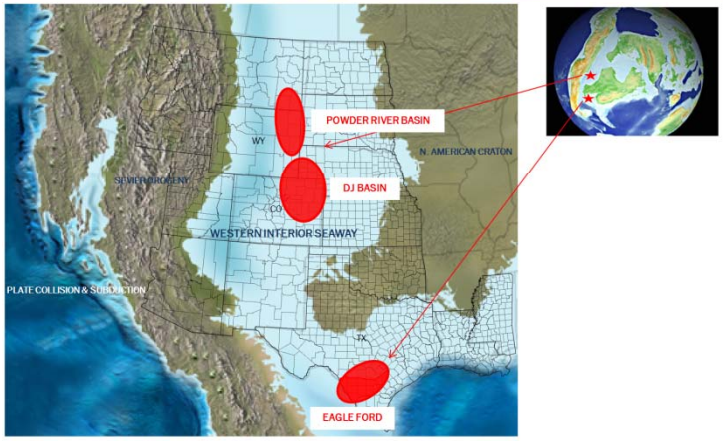


- CHK has developed the industry's leading position in the horizontal Niobrara and Frontier plays in the Powder River Basin (PRB), in Wyoming with ~405,000 net acres
- CHK has also recently entered the Niobrara and Codell plays in the DJ Basin (DJB) of northern Colorado and southern Wyoming with ~280,000 net acres
- CHK has drilled and completed 3 wells to date in these plays, 4 wells currently drilling, 2 wells waiting on completion
- In 2011 and 2012, the company plans to increase its Niobrara and Frontier operated rig count to an average of ~6 operated rigs, may rapidly increase with a JV partner
- Early success by CHK and others with IPs ranging from 500 boe/d to 1,700 boe/d
- Average EUR per well is >500 mboe

Note: Well results above are peak 24-hour rate

CHK has established a leading position in the emerging unconventional liquids-rich plays in the Rockies

Rockies Stratigraphy



WESTERN NORTH AMERICA AT TIME OF NIOBRARA DEPOSITION; U. CRETACEOUS ~85 mya (Blakey)

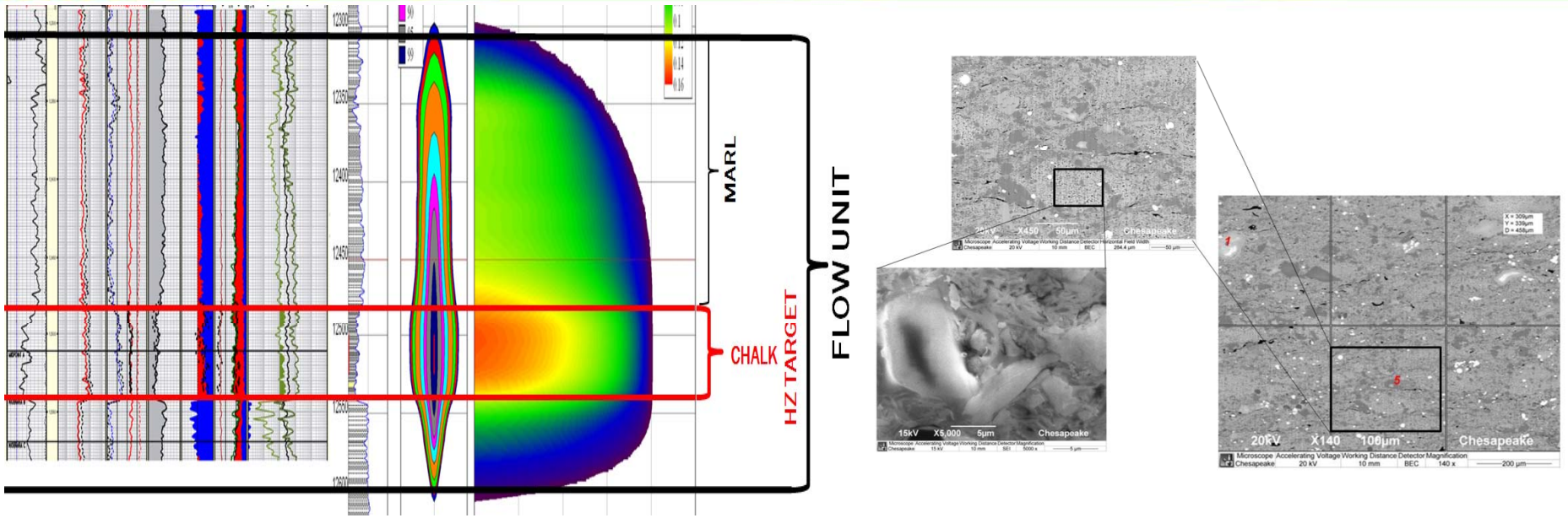
MYA	PERIOD	POWDER RIVER BASIN		DJ BASIN
		FORMATION		
0 - 65	TERTIARY	POWDER RIVER BASIN COAL		DENVER FM.
65 - 145	U. CRETACEOUS	LANCE		LARAMIE
		LEWIS SH. / TECKLA SD.		PIERRE SH. / HYGENE SD.
		MESAVERDE	TEAPOT SD.	
			PARKMAN SD.	
		STEELE SH.	SUSSEX SD.	
			SHANNON SD.	
		CODY SH.		
		NIOBRARA CARB.		NIOBRARA CARB.
				FT. HAYS LS.
		CARLILE SH.		CARLILE SH.
		FRONTIER FM.	WALL CREEK SD. / TURNER SD.	CODELL SD.
			EMIGRANT GAP	GREENHORN LS.
			BELLE FOURCHE	GRANEROS SH.
100 - 145	L. CRETACEOUS	MOWRY SH.		MOWRY SH.
		MUDDY SD. / NEWCASTLE SD.		MUDDY 'J' SD.
		DAKOTA		SKULL CREEK SH. / DAKOTA
		LAKOTA		LAKOTA

PRIMARY RESERVOIR TARGET
SECONDARY RESERVOIR TARGET

- Despite PRB and DJB being two separate structural basins, Niobrara was deposited in the same depositional basin
  - As a result, depositional fabric and reservoir facies in the Niobrara are comparable in both the PRB and DJB
- Long known as a source rock for Upper Cretaceous oil fields in the Rockies, the Niobrara formation is now a primary reservoir target as a result of technological advances in both horizontal drilling and hydraulic fracturing stimulation technology
- Additional horizontal targets in legacy vertical reservoirs include the Frontier/Turner Sand in the PRB and the Codell Sand in the DJB
- Additional horizontal resource targets underlying and overlying the Niobrara are also being evaluated
- Quiet tectonic setting with little structural complexity

There are multiple oil-resource targets above and below the Niobrara in both the PRB and DJB

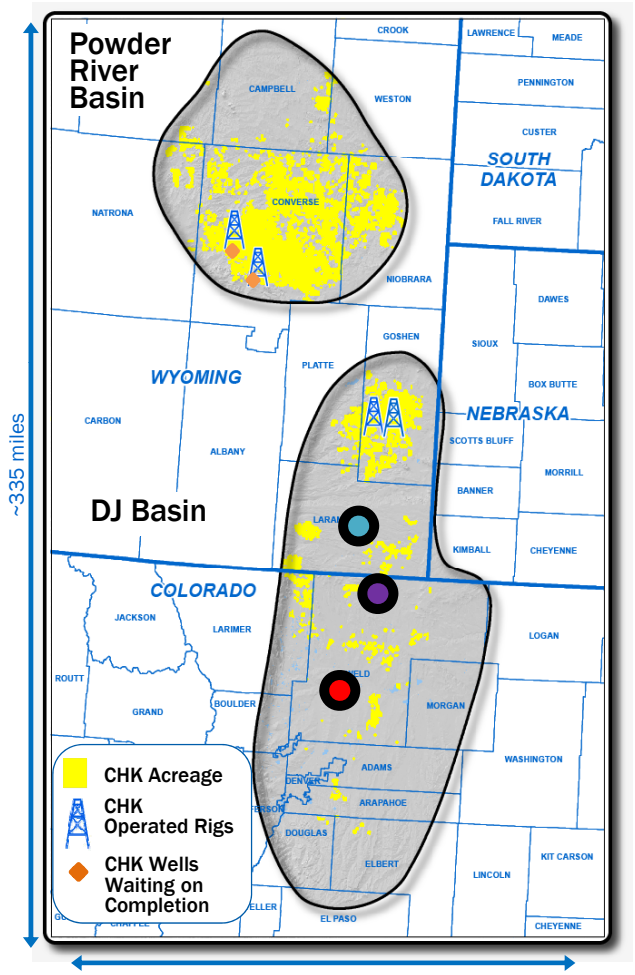
Why The Niobrara Works



- Chalk, or carbonate-rich intervals, in the Niobrara exhibits higher porosity, oil saturation, permeability and brittleness and are the preferred horizontal target in the overall flow unit
- Reservoir porosity of the Niobrara ranges from 5.5% - 7.5% in the PRB and from 7.0% - 9.0% in the DJB, and water saturation ranges from 40% - 55% in both basins
- Reservoir pressure is higher in the PRB than the DJB as a result of deeper depth of burial
- Underlying and overlying clay-rich shale serve as frac barriers in both basins
- Niobrara is the oil source rock for the giant Rockies oil fields

While thickness of the Niobrara horizontal target is typically less than 50', thickness of the flow unit, or oil resource, is ~300'

DJ Basin – Niobrara Horizontal Liquids Play



- **Industry results**
  - EOG:
    - Jake 2-01H: 3,800' Hz; 1,700 bbls/d peak rate; 764 bbls/d (64 days); 150 bbls/d stabilized rate
    - Red Poll 10-16H: 5,200' Hz; 1,100 bbls/d peak rate
    - Elmer 8-31H: 2,000' Hz; 730 bbls/d peak rate; 150 bbls/d stabilized rate
    - Critter Creek 4-09H: 5,250' Hz; 600 bbls/d (restricted rate)
    - Critter Creek 2-03H: 5,250' Hz; 570 bbls/d (restricted rate)
  - SM:
    - Atlas 1-19H: 1,500 bbls/d; Drilled under-balanced and produced 13,000 BO while drilling; 500 bbls/d stabilized rate
  - NBL:
    - Gemini K1: 900 boe/d (57 days); 60% - 70% Gas Content
- **Total of 33 wells have been drilled to date in the play**
- **9 horizontal wells currently drilling and over 175 wells permitted by over 10 different operators**

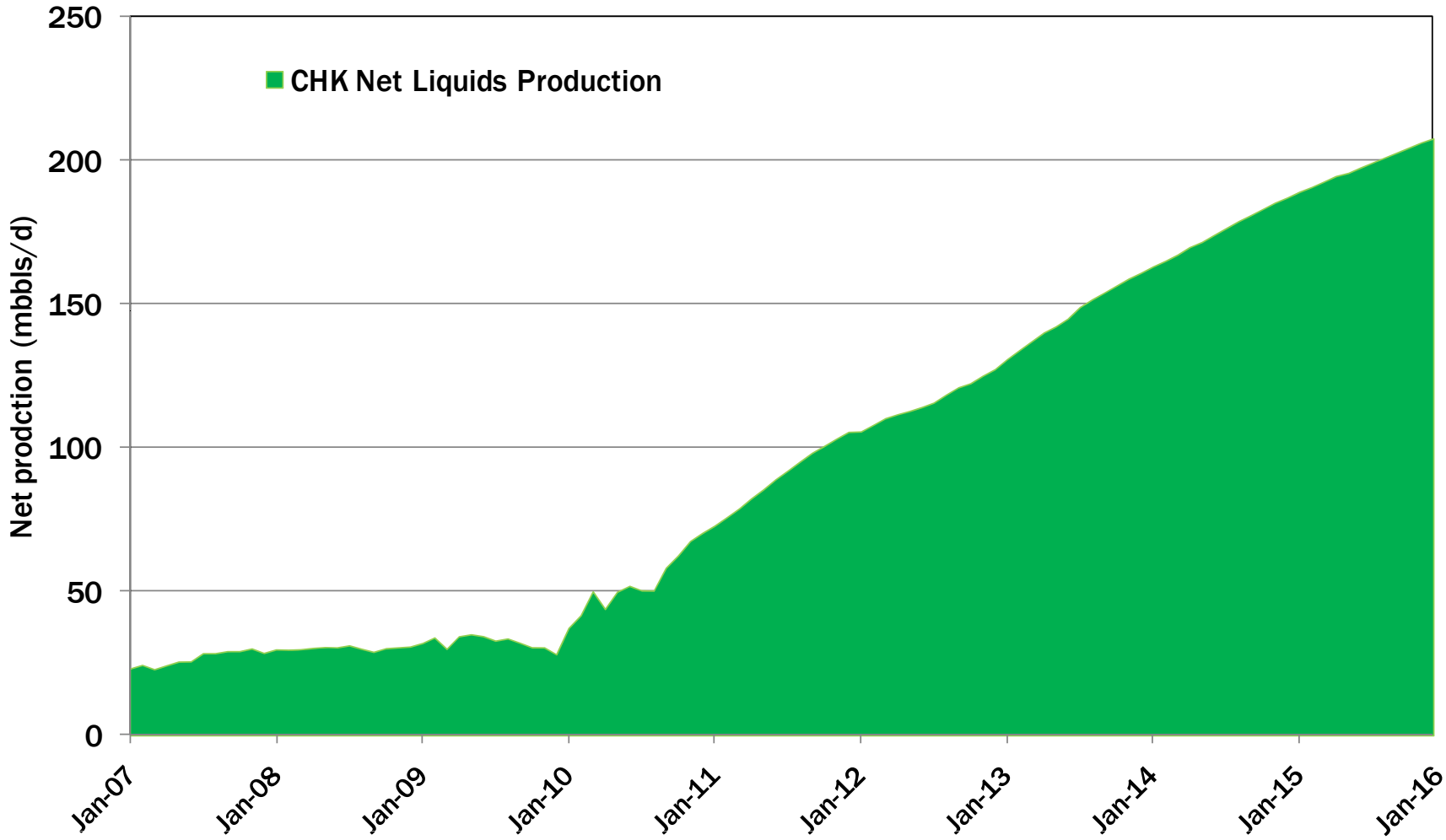
Early results validating the science

Rockies – Upside Opportunities

- Entire leasehold position in oil window
- Very high oil-in-place
- Great rock properties in a good structural setting
- Stacked horizontal pay over thousands of locations
- Ability to form large Federal units on BLM leasehold
- Good oil and natural gas takeaway infrastructure already in place
- Currently shooting 312 square miles of 3D seismic in PRB
- Plan to shoot additional 3D seismic in 2011 in both PRB and DJB
  - As result, conventional field discoveries may be found

Next large horizontal oil play in CHK's liquids inventory; CHK's next JV project

CHK Liquids – Growth Profile



Substantial liquids production growth on the way; CHK has led the nation in gas production growth and now positioned to lead the industry in growing high-margin liquids-rich plays

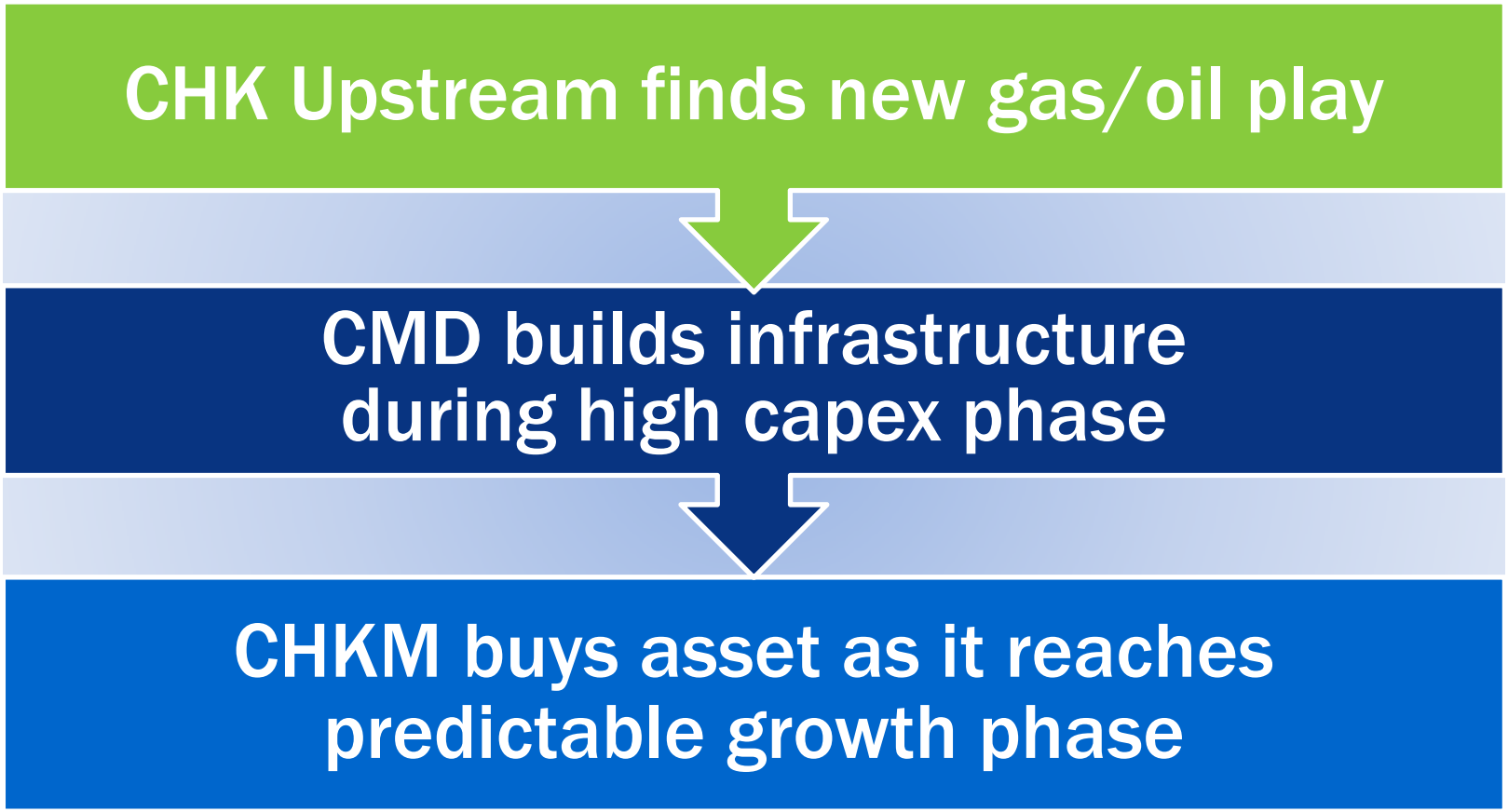
Midstream and Natural Gas Special Projects

Mike Stice, CHK SVP - Natural Gas Projects and CEO of CHKM

Chesapeake Midstream Strategy

Maximize Value of Midstream Assets	• Align risk/reward with upstream • Highlight growth opportunities • Maximize value of drop-downs
Self Fund Midstream	• Access external capital • Fund greenfield development with proceeds from mature asset sales to CHKM • Expand and extend revolver capacity
Access Low Cost of Capital	• Access tax advantages of MLP structure • Low-risk business model • Optimize balance sheet with appropriate leverage

CHKM Provides Monetization Platform for CMD/CHK



Chesapeake Midstream Partners (CHKM) – Best in Class MLP

Key Investment Highlights

- Protected distributions
- Strategically located assets
- Substantial growth potential
- Operational excellence
- World-class sponsorship
- Experienced management team

CHKM LISTED NYSE

CHKM IPO priced at $21/unit on July 29, 2010, now trading above $25/unit establishing a market cap in excess of $3.5 billion

Business Model Comparison

Comparative Assessment			
Risk factors	CHKM	Long-haul pipeline MLPs	Typical E&P MLPs
Commodity price	Minimal exposure (fixed fee)	Indirect	Direct & indirect
Re-contracting	Long-term acreage dedication	Medium-term	Short-term
Volume	Minimum volume commitment	Firm transport revenues	None
Inflation	Annual fee escalation	Depreciated rate base	None
Capital	Fee redeterminations	Rate review	None
Cost	Fixed-fee compression agreement	Cost of service	Varies
Overall business model	Best in class	Low-risk	Moderate-risk

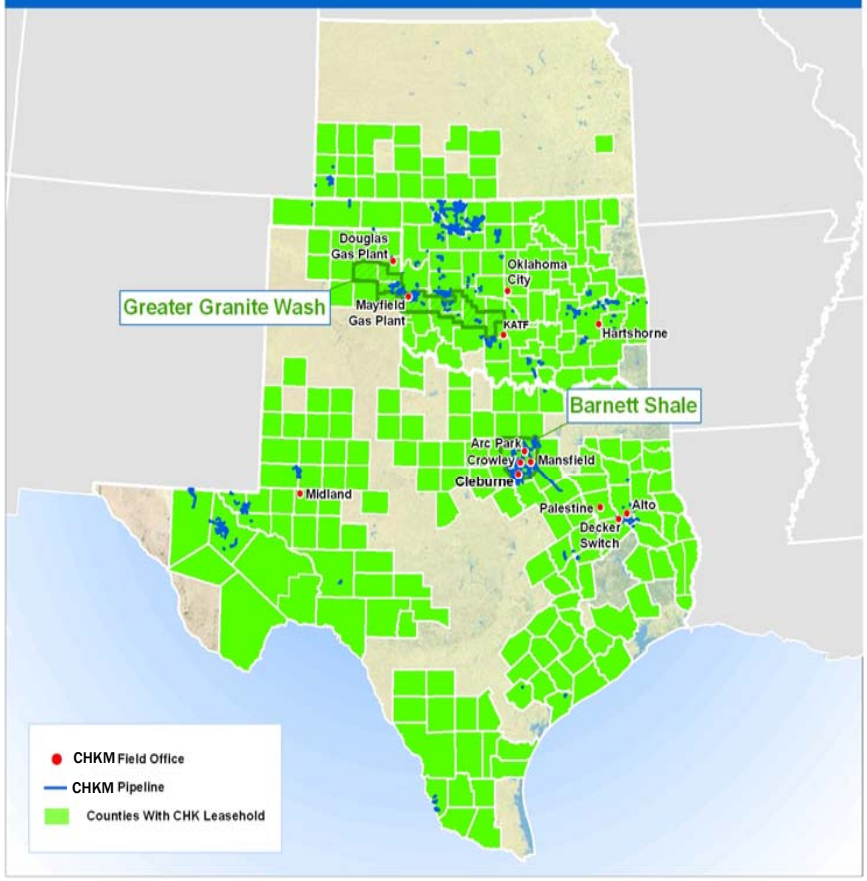
Our business model provides protected and visible distributions

Strategically Located Assets

- High-quality, scalable asset base
- High-growth unconventional plays

Key Operating Data[1]		
Dedicated acreage:	~2.4 MM acres	
Miles of pipe:	~2,900	
Volume (mmcf/d):	Barnett:	~1,060
	Mid-Continent:	~565
	Total:	~1,625
Wells gathered:	~4,000	
Direct employees:	~240	

CHKM Assets



1) Data as of June 30, 2010

CHKM owns the more mature midstream assets in CHK's portfolio

CHKM 2Q '10 Earnings

Financial Results

($ thousands)	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Revenues	$101,239	$196,625
Operating expenses	$55,790	$108,403
General and administrative expenses	$7,946	$15,196
Adjusted EBITDA	$60,948	$118,393
Net Income	$37,017	$71,931
Distributable Cash Flow	$42,922	$82,256
Adjusted Distributable Cash Flow	$57,141	$113,651
Pro forma distribution ($0.3375/unit)	$47,578	$95,156
Pro forma distribution coverage (Adj. DCF)	1.2x	1.2x

Operating Metrics

	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Barnett Shale		
Wells connected during period	67	120
Throughput (mmcf/day)	1,059	1,019
Mid-Continent		
Wells connected during period	29	60
Throughput (mmcf/day)	565	558
Total		
Wells connected during period	96	180
Throughput (mmcf/day)	1,624	1,577

- 2Q '10 volume up 6% from 1Q '10 driven primarily by Barnett
- 2Q '10 adjusted EBITDA up 6% from 1Q '10
- Pro forma distribution coverage 1.2x

1) Reconciliations of non-GAAP financial measures to comparable GAAP measures appear on page 15 of this presentation

Substantial Growth Opportunities

Growth Dimension	Competitive Strengths	Growth Potential
Organic	• Established platform • Operational excellence	• Third-party volumes • Pad development opportunities
Drop-down	• CHK relationship • Contractual provisions (ROFO)(1)	• Substantial drop-down inventory • Access to CHK future growth
Acquisitions	• Scalable footprint • Attractive cost of capital	• Bolt-on opportunities • Partnerships with other producers

1) ROFO = right of first offer

Chesapeake Midstream Development (CMD)

	CHKM	CMD
Basins	5	5+
Throughput	1.6 bcf/d	1.5 bcf/d
Growth	Moderate growth	High growth
Miles of pipe	2,880	1,780
NTM Adjusted EBITDA(1)	$300 mm	$160 mm
Valuation	$3.5 billion(2)	$1.9 billion(3)
CHK ownership	42%	100%
Net CHK Value	$1.5 Billion	$1.9 Billion

Chesapeake has ownership in two multi-billion dollar midstream businesses

1) Estimates for next twelve months (NTM) period ending 6/30/2011. Reconciliations of non-GAAP financial measures to comparable GAAP measures appear on page 15 of this presentations
2) Based on CHKM unit price of $25.00 per unit
3) Based on 12x adjusted EBITDA multiple

CMD Drop-down Candidates[1]

Basin	Assets	Miles of Pipe	Throughput (mmcf/d)
Haynesville	Springridge GGS[2]	190	370
	Mansfield GGS[2]	160	460
Fayetteville	Little Creek/Shirley GGS[2]	370	350
Marcellus	North Marcellus	40	150
	Central Marcellus	330	70
Eagle Ford	Eagle Ford	10	5
Other	Compression, etc.	N/A	N/A

CHK is the key source of abundant growth opportunities

1) Reflects current views of CHK management. Drop-down transactions are negotiated at arm's length and are subject to CHKM board and conflicts committee approval. They may not occur as and when described, or at all.
2) Gas gathering system

Natural Gas Special Projects Objectives

- **Look for opportunities through direct investment or partnering arrangements to facilitate projects that can:**
  - Have a material impact on natural gas demand
  - Diversify CHK price risk away from natural gas markets to other markets where greater margin is available
    - Gas-to-crude and gas-to-electricity
  - Provide CHK access to global market pricing
  - Focused on GTL processes and LNG exports
- **Avoid opportunities that:**
  - Have substantial R&D and commercialization risks
  - Are dependent on long-term subsidies
  - Are not compatible with CHK's existing portfolio of business
  - Take substantial amounts of capital away from CHK's core business

Special projects target opportunities that could provide a step change in the value of domestic natural gas - current focus is domestic GTL and LNG export

Gas-to-Liquids (GTL)

- **Why GTL?**
  - Diversify CHK price risk away from natural gas toward liquids markets
  - Increase the demand for domestic natural gas
- **GTL overview:**
  - GTL has historically been a stranded gas solution
  - Active industry R&D in *Fischer-Tropsch*, syngas generation and a variety of syngas-to-fuels generation processes
  - Increasing spread between the price of natural gas and crude
    - GTL technology can capture the difference in the spread and monetize it
    - CHK believes that the GTL technology and operational techniques have progressed sufficiently to allow GTL to be profitable in a market economy
- **CHK is:**
  - Engaged on several fronts in order to evaluate the economic viability of modern GTL technology in U.S. markets
  - Encouraged by prospects that economic solutions for U.S. applications may be on the near-term horizon across a broad range of applications (small-, medium- and large-scale plants)

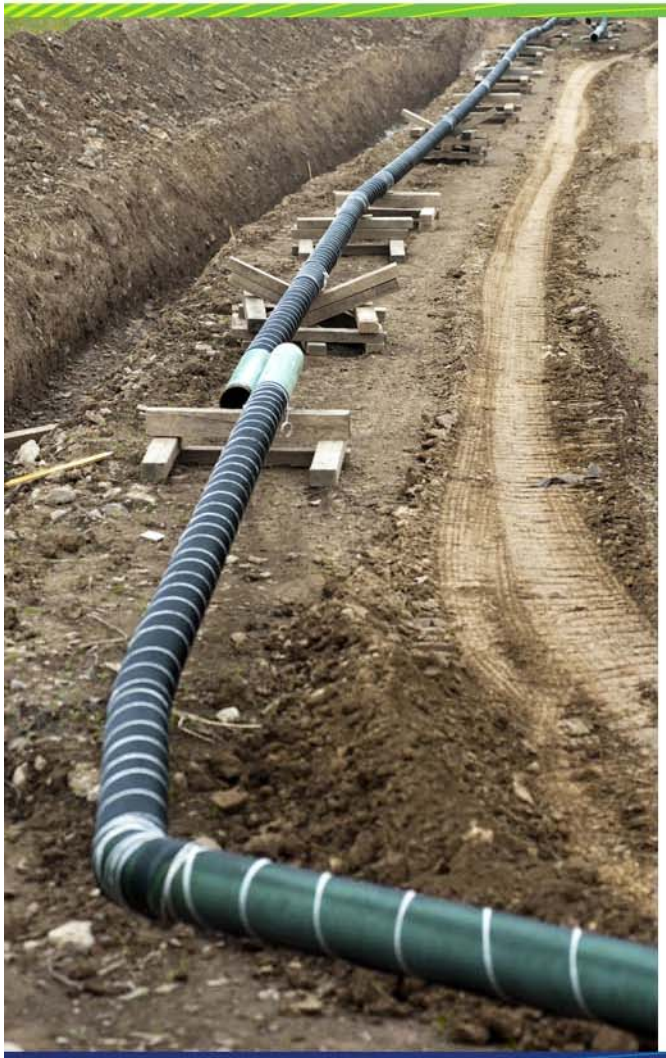
Profitable and scalable GTL could be the Holy Grail for U.S. natural gas

LNG Export

- **Why LNG export?**
  - Diversify CHK price risk away from domestic natural gas markets toward worldwide natural gas markets and liquids based price indices
  - Increase the demand for domestic natural gas
  - Increase optionality
- **LNG export overview:**
  - Some opportunities to add export facilities to underutilized import terminals in the U.S.
  - May be a viable option for exporting to countries with Free Trade Agreements with the U.S. or World Trade Organization members
- **CHK is:**
  - Seeking to support viable projects through gas supply contracts
  - Not likely to pursue direct investment in LNG export projects
    - Not necessary – projects are attractive enough to access third-party capital

Globalizing domestic natural gas increases optionality

Midstream and Natural Gas Special Projects Summary



- **Chesapeake's value maximization strategy of midstream assets is working**
- **Drop-down opportunities provide growth for CHKM and a vehicle for monetizations for CHK**
- **CHKM performing and trading well**
  - 2Q '10 adjusted EBITDA up 6% from 1Q '10
  - Pro forma distribution coverage 1.2x
  - Units currently trading above $25.00, IPO at $21 on July 29, 2010
- **CMD growing rapidly**
  - In excess of 20% increase in miles of pipe YTD
  - In excess of 50% increase in volumes YTD
- **Special projects focused on sustainable demand growth**
  - GTL plant deployment
  - LNG export

CHKM 2Q Non-GAAP Reconciliations

The following table presents a reconciliation of the non-GAAP financial measures of Adjusted EBITDA , Distributable Cash Flow and Adjusted Distributable Cash Flow to their most closely related GAAP financial measures:

	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010	Twelve Months Ended June 30, 2011
Net income	$ 37,017	$ 71,931	$ 203,900
Adjust for:			
Interest expense	526	1,137	3,800
Depreciation and amortization expense	23,442	45,392	92,500
(Gain) Loss on sale of assets	(37)	(67)	—
Adjusted EBITDA	$ 60,948	$ 118,393	$ 300,200
Cash provided by operating activities	$ 79,084	$ 197,409	
Adjust for:			
Changes in assets and liabilities	(18,688)	(80,195)	
Maintenance capital expenditures	(17,500)	(35,000)	
Other non-cash items	26	42	
Distributable cash flow	42,922	82,256	
Adjust for:			
Implied minimum volume commitment	14,219	31,395	
Adjusted distributable cash flow	$ 57,141	$ 113,651	

• Adjusted EBITDA represents net income (loss) before income tax expense, interest expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results. Distributable cash flow represents CHKM's Adjusted EBITDA, plus interest income, less net cash paid for interest expense; maintenance capital expenditures; and income taxes. Distributable cash flow does not reflect changes in working capital balances. Adjusted EBITDA and distributable cash flow are non-GAAP supplemental financial measures that management and external users of CHKM's consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess (a) CHKM's operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to capital structure, historical cost basis or financing methods; (b) its ability to incur and service debt and fund capital expenditures; (c) the ability of CHKM's assets to generate sufficient cash flow to make distributions to unitholders; and (d) the viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities. CHKM management believes that the presentation of Adjusted EBITDA and distributable cash flow provides useful information to investors in assessing CHKM's financial condition and results of operations. The GAAP measures most directly comparable to Adjusted EBITDA and distributable cash flow are net income and net cash provided by operating activities, respectively. Each of Adjusted EBITDA and distributable cash flow has important limitations as an analytical tool because it excludes some but not all items that affect net income and net cash provided by operating activities. You should not consider either Adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of CHKM's results as reported under GAAP. Because Adjusted EBITDA and distributable cash flow may be defined differently by other companies, CHKM's definitions of Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Strategic Overview

Aubrey McClendon - CEO

CHK's Strategic View

- CHK has been early to recognize and capitalize on most every major industry opportunity and trend in the past 20 years and has also been at the forefront in mitigating risk through hedging, JV partnerships and long-term debt
- CHK has assembled an unparalleled portfolio that is valuable now and worth much more in the future
  - CHK's JVs have validated this strategy
  - #1 position in natural gas shales
  - Building the premier unconventional liquids position to become a Top 5 U.S. oil producer in the next five years
- The window of opportunity in new concept play discovery is finite
- Monetizations and JVs have been an effective way to fund the capture and growth of our industry-leading resource base
- Future monetizations and JVs will allow CHK to continue growing per share NAV at a top of industry rate
- CHK will continue to dynamically adapt to market conditions and economic incentives and remain an industry leader in the process

The winners over the next two decades (at least) have likely been predetermined by the land acquisition choices made from 2005 to 2010

CHK History – It's Relevant For Today's Discussion

- **Founded in 1989 with $50,000 and 10 employees to capitalize on new technology of horizontal drilling**
  - Were looking for ways to make co-founders' land expertise relevant in the industry
  - Started in unconventional plays of Austin Chalk in southeast TX and Golden Trend and Sholem Alechem fields of south-central OK
  - Early JV partners Arco, Hess and Belco carried the early drilling capex burdens – sound familiar?
  - In many ways, CHK's current strategy is same as it was 21 years ago
- **1989–1999: Phase One of CHK's History**
  - Used horizontal drilling and JV partners to develop large unconventional land plays
- **2000–2004: Phase Two of CHK's History**
  - "Get long gas" – CHK sees rise of merchant power industry and electrical power demand growth trend as gas price game changers

CHK History, Continued

- **2005–2008: Phase Three of CHK's History**
  - "Get long gas" transitions to a focus on the unconventional gas land grab as a result of realization that the Barnett Shale is "for real" and a "game changer"
  - Barnett officially accepted as commercial by the industry in 2005; leads to Fayetteville, Marcellus, Haynesville, Bossier and Eagle Ford gas shale plays in just three short years
  - CHK determined to become #1 or #2 in each of these plays to be able to create greater value for decades to come from "forever" assets – mission accomplished!
- **2009–??: Phase Four of CHK's History**
  - Any chance of long-term U.S. gas shortage goes away for good in 2009
  - By 2008, success of the Bakken convinces industry (and CHK) that oil and NGL's can be moved through tight rock, – even shale
  - Having missed the Bakken, CHK determined to be #1 or #2 in all other unconventional liquids-rich plays; so far achieved success in: Granite Wash, Cleveland, Tonkawa, Mississippian, Wolfcamp, Avalon, Bone Spring, Eagle Ford, Niobrara, others to come…

History of CHK's Unconventional Plays

Anadarko Basin

4Q '04
Colony and TX PH
Granite Washes

Anadarko Basin

4Q '05
Cleveland/Tonkawa

Delaware and
Midland Basins

4Q '06
Bone Spring

Anadarko Basin

1Q '07
Mississippian

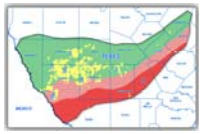
Delaware
Basin

4Q '08
Avalon
Shale

Rockies

4Q '08
Niobrara
and Frontier

Eagle Ford Shale



4Q '09

Emphasizing liquids

Big Oil

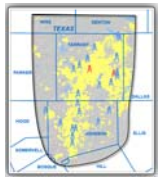
Others on
the way

?

De-emphasizing natural gas

Big Gas

Barnett Shale

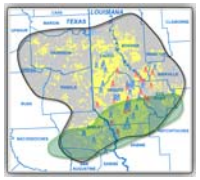


4Q '04

Fayetteville Shale

1Q '06

Haynesville Shale

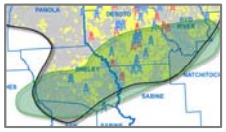


2Q '07

Marcellus Shale

3Q '07

Bossier Shale



2Q '09

Note: dates indicate spud of first well

2000–10: CHK's U.S. Natural Gas Production Rank Climbs from #15 to #2
2010–15: CHK's U.S. Liquids Production Rank Could Rise from #17 to #5

Play	Year Entered	Leasehold (net acres)	CHK Rank in Industry	Proved Reserves (Bboe)	Unrisked Unproved (Bboe)
Bakken	Failed in '04, '05 and in '08	0	0	0	0.0
Anadarko Basin: Granite Washes	2004	200,000	#1	0.25	1.3
Anadarko Basin: Cleveland/Tonkawa, Mississippian	2005/2007	730,000	#1	0.05	2.2
Permian Basin: Avalon Shale, Bone Spring, Wolfcamp	2006/2008	615,000	#1	ND	1.7
Powder River and DJ Basin: Niobrara/Frontier	2008	685,000	#1	ND	2.3
Eagle Ford Shale(1)	2009	625,000	#1	ND	3.5
Undisclosed New Plays	2010	1,000,000	#1	ND	ND
Totals		**3,855,000**	**#1**	**0.30**	**10.0 - 15.0**

- Who believed we could move from a Top 15 to a Top 2 natural gas producer in 10 years? No one!
- Who believes we can move from a Top 20 to a Top 5 liquids producer in 5 years? No one!
- Who believes we could be sitting on 10-15 billion barrels of liquids? No one!

ND denotes "not disclosed"
1) CHK's Eagle Ford Shale leasehold will total 425,000 net acres post closing of transaction with CNOOC

What are the consequences for an investment in CHK if perhaps, somehow, we are right about what liquids resources we own?

Why Spend So Much Money On Leasehold?

Three Major Reasons:

- First, it creates value. The latest example is the Eagle Ford Shale. CHK was a late entrant with first leases acquired in 11/09, reached 300,000 net acres by 3/10, reached 625,000 net acres by 10/10, invested $1.4 billion, have agreed to sell 200,000 net acres for $2.2 billion, leaving 425,000 net acres and 2.3 billion Boe possible to CHK at a *negative* cost of *$800 mm*. What value did this create? We think $7-10 billion. Should we do it again if we can? Would you?
- Second, it is simply a very cheap way to buy oil options. Leasehold investments are no longer risky in the traditional sense. Today they represent a very cheap option on a known resource. At $2,200 per acre (CHK's cost), a CHK Eagle Ford acre overlays ~5,000 bbls of recoverable oil. That's an option cost of ~$0.40/barrel plus $15.00 to develop it. Meanwhile, a financial option on oil (a call) sells for ~$20.00/bbl (at strip prices covering 2015-18). Is it smarter to buy a call option on a barrel of oil at $20/bbl where the strike price = $90/bbl for an all-in cost of $110/bbl, or is it smarter to pay $0.40/bbl and a $15.00/bbl "strike" price for an all-in cost of $15.40/bbl?
  - Our development costs of $10-15/bbl is effectively the strike price of this option
- Third, where else in the world, in any industry, can you buy an asset for $1-1.5 billion and have it become worth >$5 billion within one year? Nowhere!

What Value Has CHK Leasehold Spending Created to Date?

- Let's examine what CHK has created through undeveloped leasehold expenditures in its major shale plays
- During past 5 years (2005-10), CHK has invested $14 billion on leasehold in the Big 5 shale plays

Play	Amount invested in leasehold ($mm)	Less JV cash and carry ($mm)	% of CHK leasehold sold	Post JV leasehold	Net leasehold cost remaining ($mm)	Net leasehold remaining cost/net acre	Proved reserves and risked unproved resources remaining (Bcfe)	Leasehold cost per proved and risked unproved resource mcfe
Barnett	$4,100	($2,250)	25%	220,000	$1,850	$841	6,300	$0.29
Fayetteville	$590	($1,900)	25%	465,000	($1,310)	($282)	10,100	($0.13)
Haynesville/Bossier	$5,520	($3,160)	20%	530,000	$2,360	$445	26,600	$0.09
Marcellus	$2,450	($3,375)	32.5%	1,550,000	($925)	($60)	34,900	($0.03)
Eagle Ford	$1,380	($2,160)	33.3%	425,000	($780)	($184)	5,600	($0.14)
Total	$14,040	($12,845)	Various	3,190,000	$1,195	$375	83,500	$0.01

- To recap, in the Big 6 shale plays, CHK owns 3.2 mm net acres at an average cost of $375/net acre and $0.01/mcfe - so, what exactly is the problem?

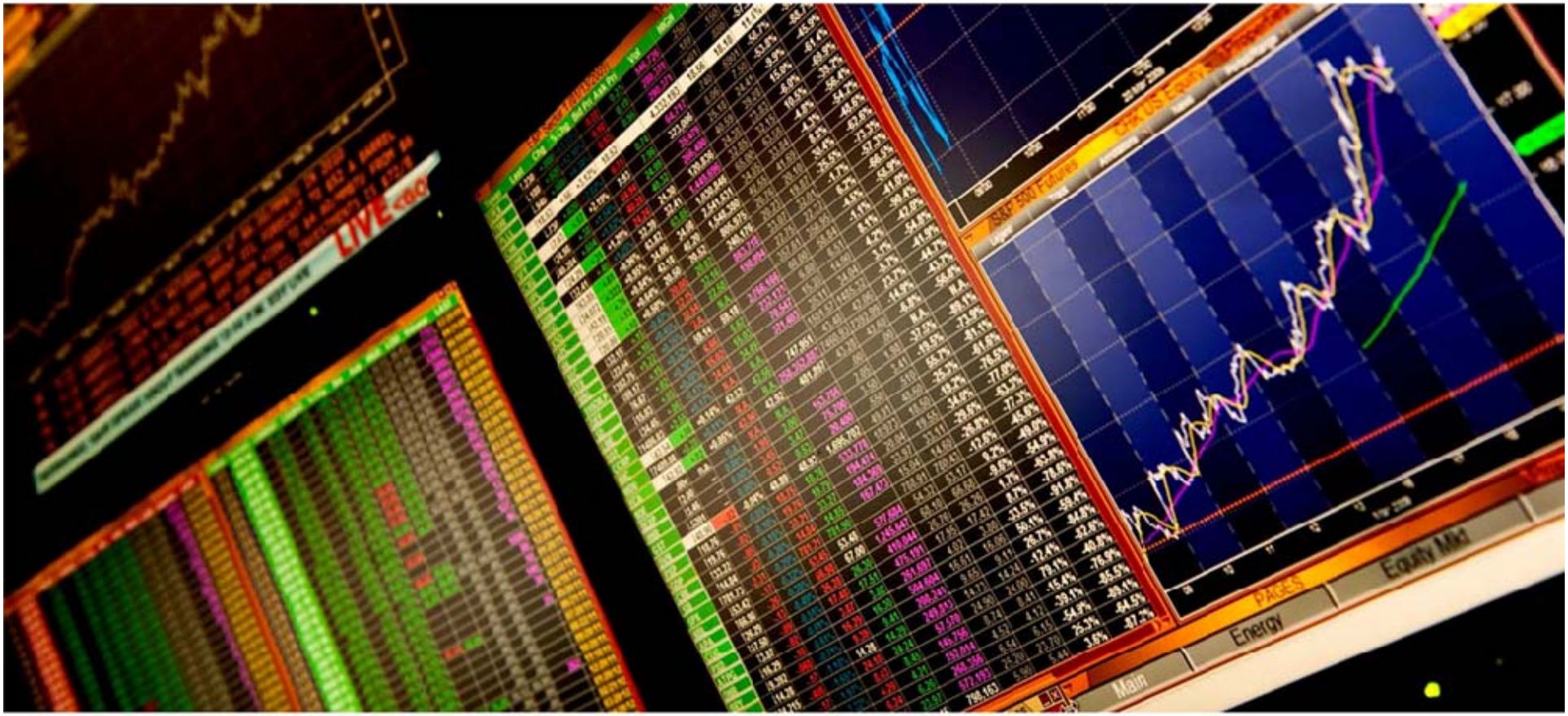
So, What Would You Do???

- If you knew where the next Eagle Ford Shale was and you knew you could acquire 1,000,000 net acres at a cost of, say, $1.25 billion, would you do it?
- What if you knew you could sell 25% of that new 1,000,000 net acres within one year of acquisition for, say, $2.5 billion and still own 750,000 net acres at a cost of negative $1.25 billion, would you do it?
- What if you were confident there was ~3.75 billion barrels of recoverable oil equivalent under that 750,000 net acres and your option price to control those ~3.75 billion barrels was a negative $0.35/bbl, would you do it?
- And what if you knew some investors would criticize you for making this investment despite the likelihood it would create >$10 billion of value for your company, would you do it?
- If you wouldn't do it, why not?
- If we have the opportunity to create >$10 billion of value for CHK in a new JV, we will do it and we can't imagine why anyone would disagree with us, would you?

The biggest mystery of life? Having sold $3.1 billion of leasehold for $13 billion in five deals (with no failures), and having retained "stub" value of $37 billion, some investors want us to stop creating value this way – in our respectful opinion, that is nuts

Financial Overview

Marc Rowland, Executive Vice President – Finance & CFO



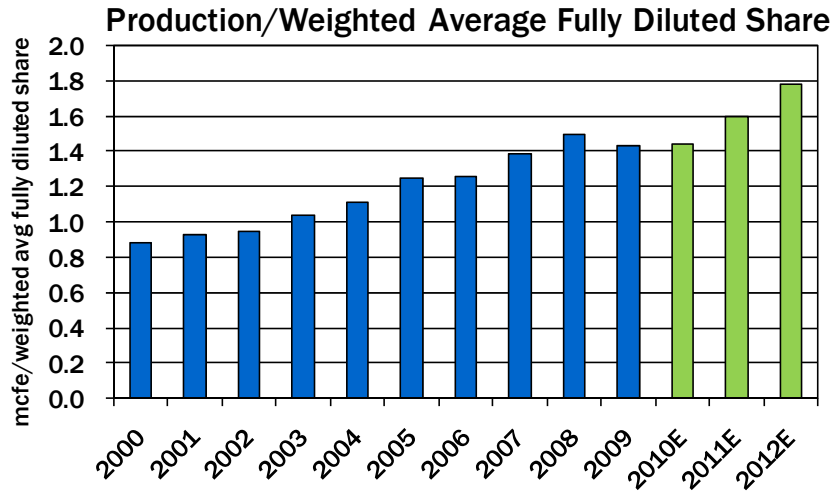
Financial Highlights

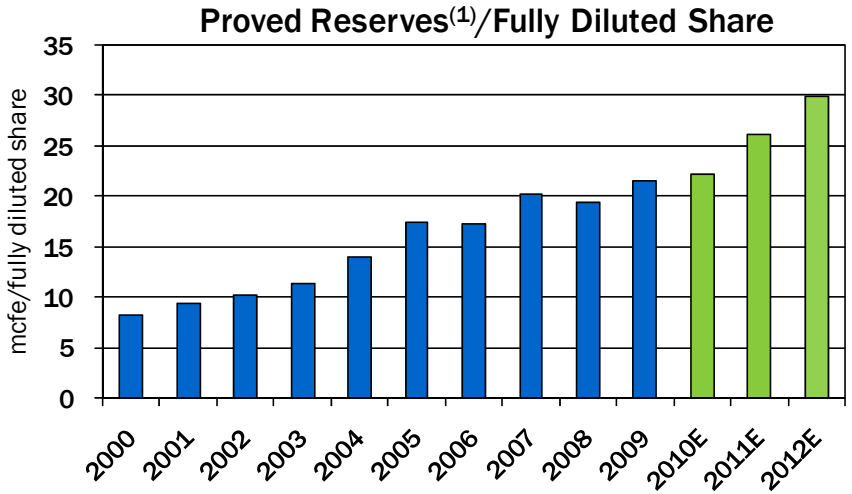
- **~$30 billion enterprise value**
  - ~$16.7 billion equity value, ~$10.7 billion net long-term debt and ~$(2.2) billion working capital
- **Strong profitability**
  - 2010E: ebitda $5.1 billion, operating cash flow $4.9 billion, adj. net income to common $2.0 billion
  - 2011E: ebitda $5.5 billion, operating cash flow $5.3 billion, adj. net income to common $2.0 billion
  - 2012E: ebitda $5.2 billion, operating cash flow $4.9 billion, adj. net income to common $1.6 billion
- **Attractive hedging position**
  - 51% of 2H'10, 42% of 2011 production hedged at average prices of $8.32/mcfe and $7.10/mcfe, respectively
- **Innovative joint venture arrangements: ~$13 billion of proceeds to date**
  - CHK/PXP in Haynesville Shale: $3.2 billion for 20% interest
  - CHK/BP in Fayetteville Shale: $1.9 billion for 25% interest
  - CHK/STO in Marcellus Shale: $3.4 billion for 32.5% interest
  - CHK/TOT in Barnett Shale: $2.3 billion for 25% interest
  - CHK/CEO in Eagle Ford Shale: $2.2 billion for 33.3% interest
- **Well structured balance sheet**
  - Staggered long-term maturity structure
  - Strong asset and cash flow coverage of debt
  - Substantial asset growth, cash generation, asset monetization and earnings set to meaningfully deleverage CHK over the next several years
- **Anticipating further improvement to debt metrics**
  - Able to add 2.5-3.5 tcfe per year of new proved reserves (after replacing production) at ~$1.00/mcfe per year for years to come

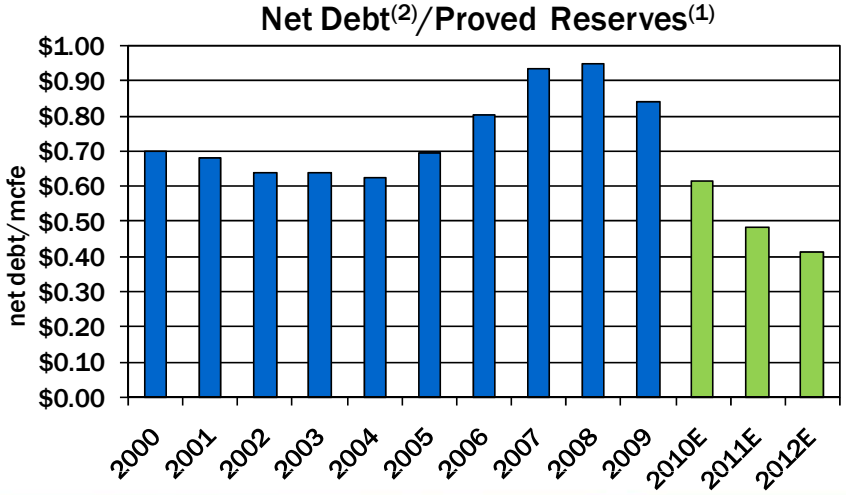
Data above incorporates:

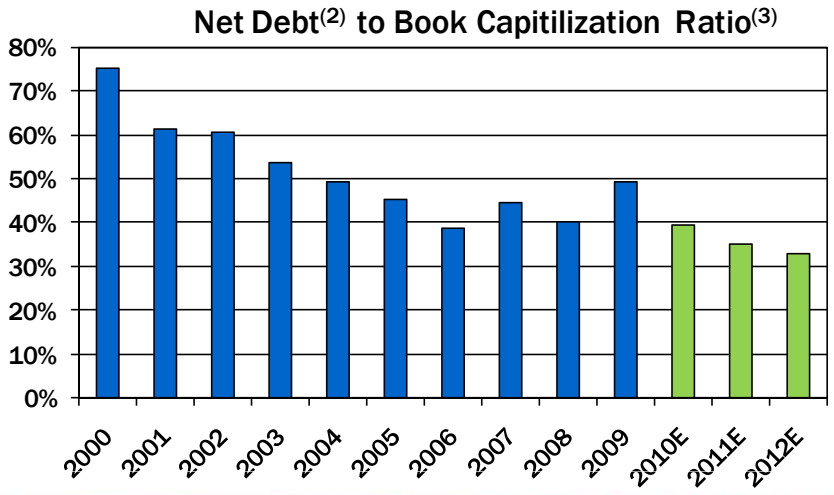
- Outlook issued 10/12/10
- Summary of 2010 – 2012 financial projections appear on pages 25-27
- Summary of hedging positions appear on page 22
- An assumed common stock price of $22.00, NYMEX prices of $5.00/mcf and $80.00/bbl for 2010-12 and excludes effects unrealized hedging gain or loss
- Net debt = long-term debt less cash

CHK Keeps Delivering Per Share Growth









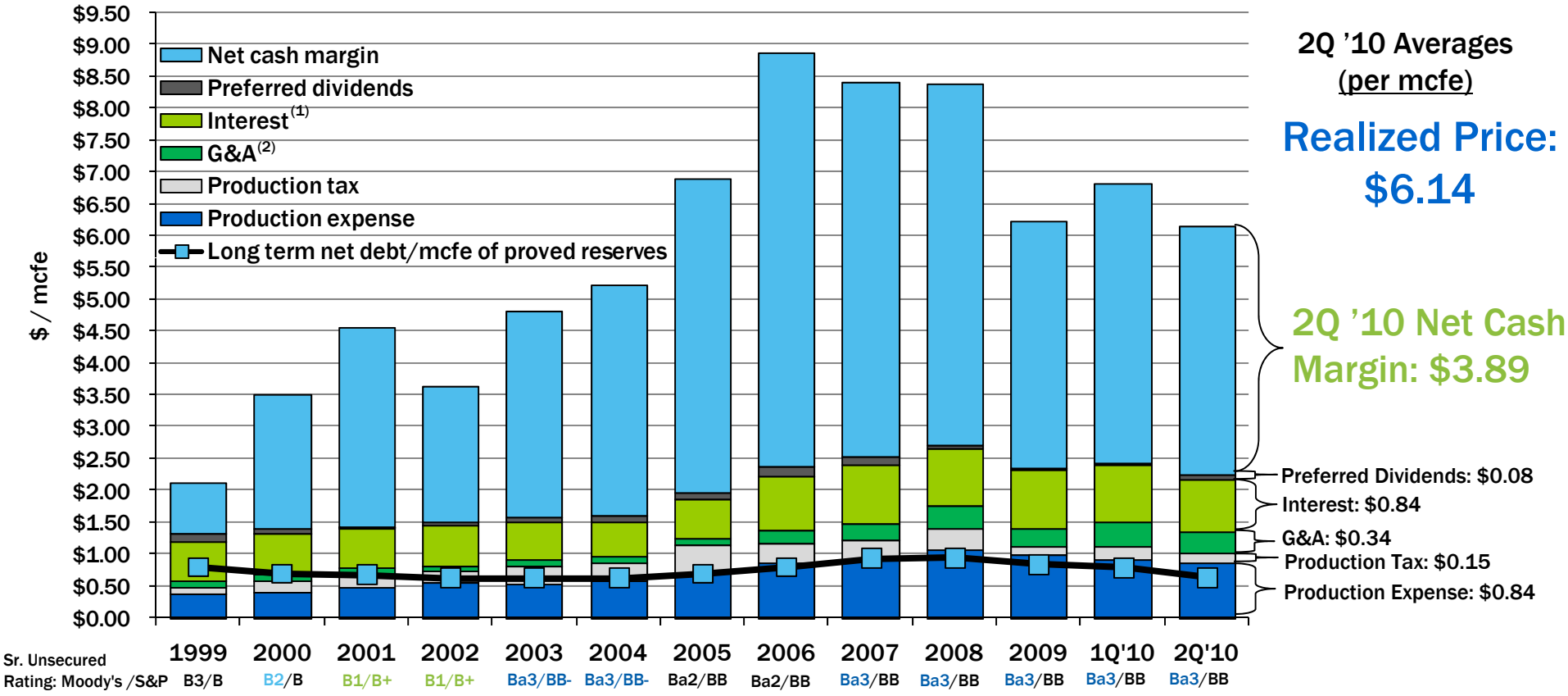
Impressive production and reserve growth per share along with decreasing financial leverage

Data above incorporates:

- CHK's Outlook dated 10/12/10

1) Reserve growth based on 2.5 - 3.5 tcfe add per year
2) Net debt = long-term debt less cash
3) Assumes NYMEX prices of $5.00 per mcf and $80.00 per bbl in 2010 - 2012

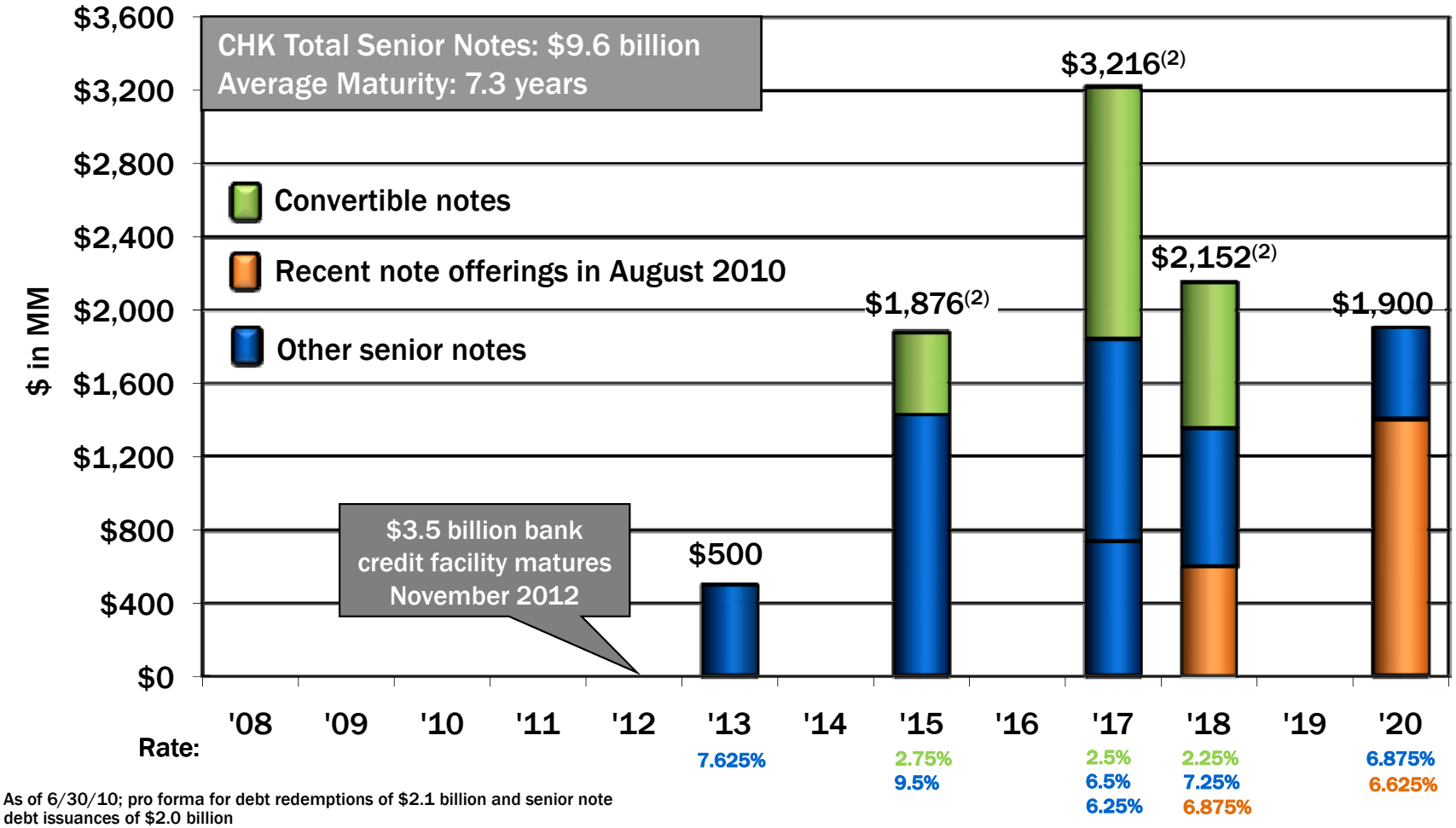
Strong Cash Margins and Declining Debt Levels per Mcfe



Total Cash Expenses = $2.25

(1) Interest expense + capitalized interest, excluding unrealized gains/losses
(2) Excludes stock based compensation

Senior Note Maturity Schedule(1)



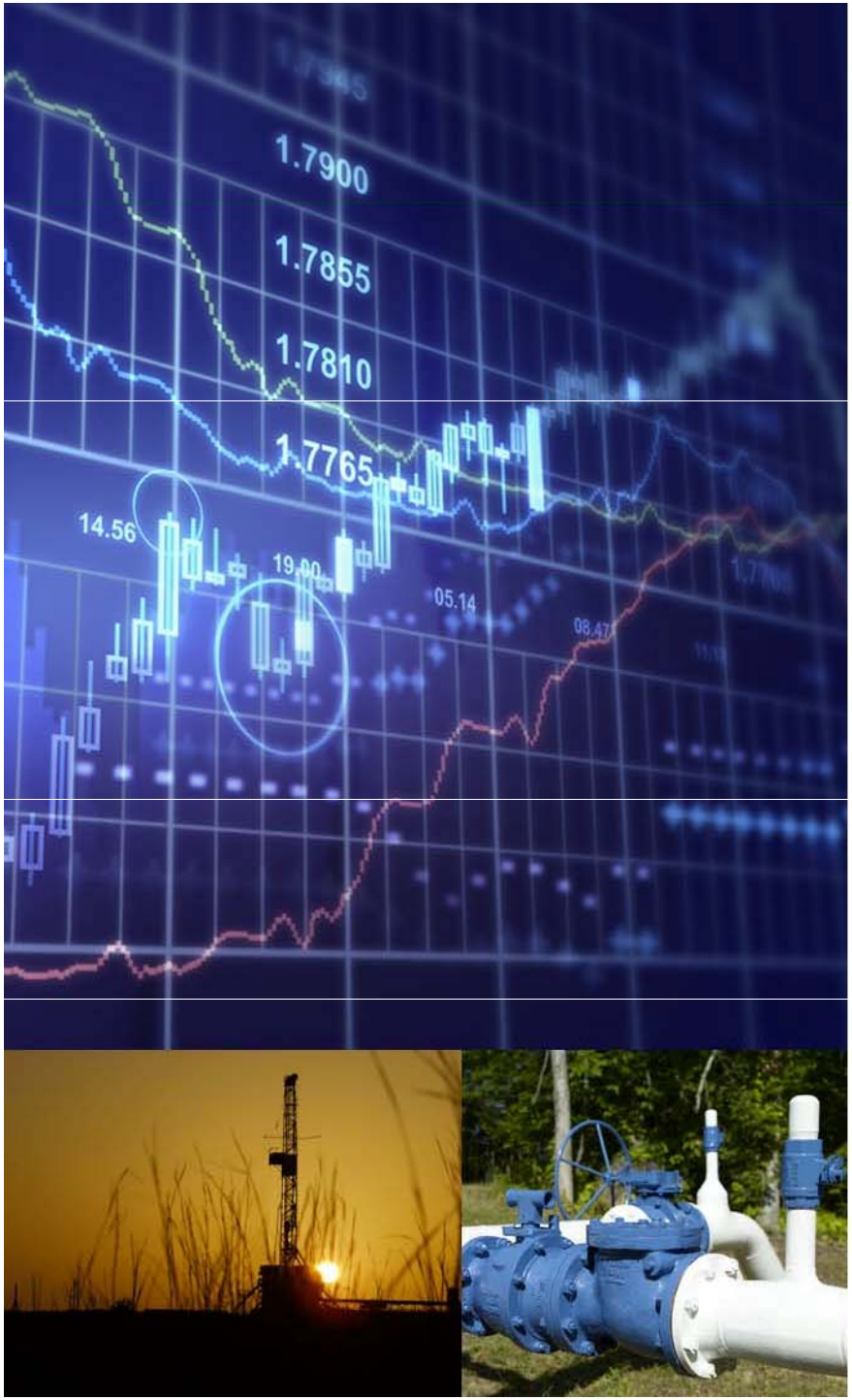
1) As of 6/30/10; pro forma for debt redemptions of $2.1 billion and senior note debt issuances of $2.0 billion
2) Recognizes earliest investor put option as maturity for the 2.75% of 2035, 2.5% of 2037 and 2.25% of 2038 Convertible Senior Notes shown in green

Only $500 million of senior note maturities by February 2015

Debt Per Proved Mcfe Analysis

(as of 6/30/10, $ in millions)	1H '10[1]
Proved reserves (bcfe)	15,459
Proved developed reserves (bcfe)	8,388
Long-term debt	$10,501
Less: cash	($601)
Long-term debt net of cash	$9,900
Net debt/mcfe of proved reserves	$0.64
Net debt/mcfe of proved developed reserves	$1.18
Less: remaining drilling carries discounted at 10%	($2,300)
Less: debt allocated to midstream and other service operations	($1,000)
Plus: PV10 of future operating costs on existing VPPs 1-7	$438
Effective net debt on E&P operations	$7,038
Effective net debt/mcfe of proved reserves ($/mcfe)[2]	$0.46
Effective net debt/mcfe of proved developed reserves ($/mcfe)[2]	$0.84

1) Excludes pro forma benefit of $2.16 billion Eagle Ford Shale JV and $1.15 billion VPP #8
2) As of 6/30/10, investment grade peers' debt/proved reserves and debt/proved developed reserves is $0.35 and $0.54 respectively. Peers include: APA, APC, DVN, ECA, EOG



Strategic and Financial Plan Update

2010 - 15 Strategic and Financial Plan Update

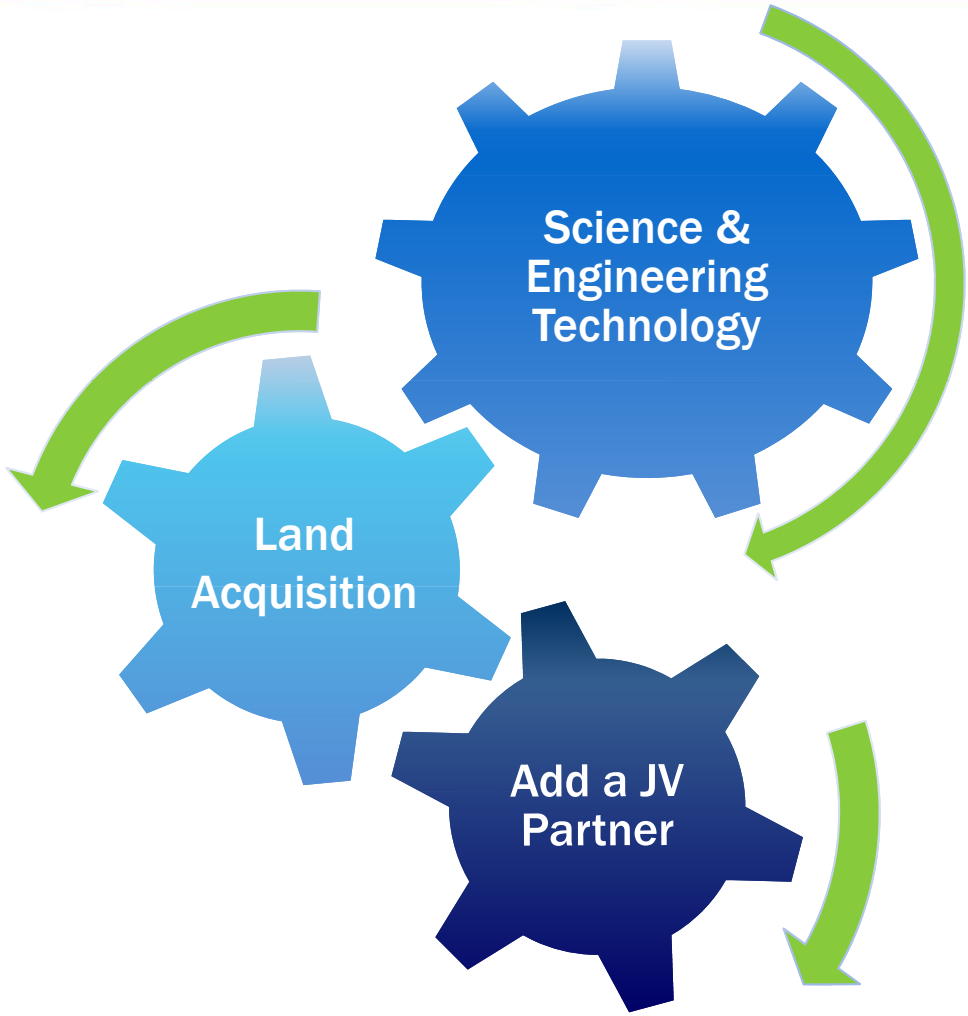
- **CHK has already accomplished multiple parts of its strategic and financial plan that was announced in May 2010**
- **During 2Q-3Q 2010, CHK has:**
  - Issued $2.6 billion of convertible preferred stock (primarily to Asian investors)
  - Called for redemption or tender of $3.4 billion of senior notes and issued $2.0 billion in new Senior Notes
  - Sold 428 bcfe of proved reserves through VPP7 and VPP8 for proceeds of ~$1.5 billion
  - Sold ~$385 million of leasehold and producing properties
- **Improved credit metrics in 1H'10**
  - 6/30/10 net debt(1) to total book cap ratio down 18% in 6 months to 40% from 49% as of 12/31/09
  - 6/30/10 net debt(1) per proved reserve ratio down 24% in 6 months to $0.64/mcfe from $0.84/mcfe as of 12/31/09
- **In 2010, CHK invested heavily in new leasehold acquisitions in various liquids-rich plays**
- **In 4Q'10 and 2011, CHK will focus further on recapturing a significant portion of these new leasehold expenditures through joint ventures and asset monetizations**
  - Announced $2.2 billion Eagle Ford transaction with CEO, closing anticipated in 4Q '10
  - Further JVs are planned for late 2010 and early 2011; Niobrara is next
  - Potential Marcellus monetization of up to 20%
  - Other upstream transactions
  - CMD drop-downs to CHKM, facilitated by the Q3 2010 CHKM IPO

1) Net Debt = long-term debt less cash

Joint Venture Overview

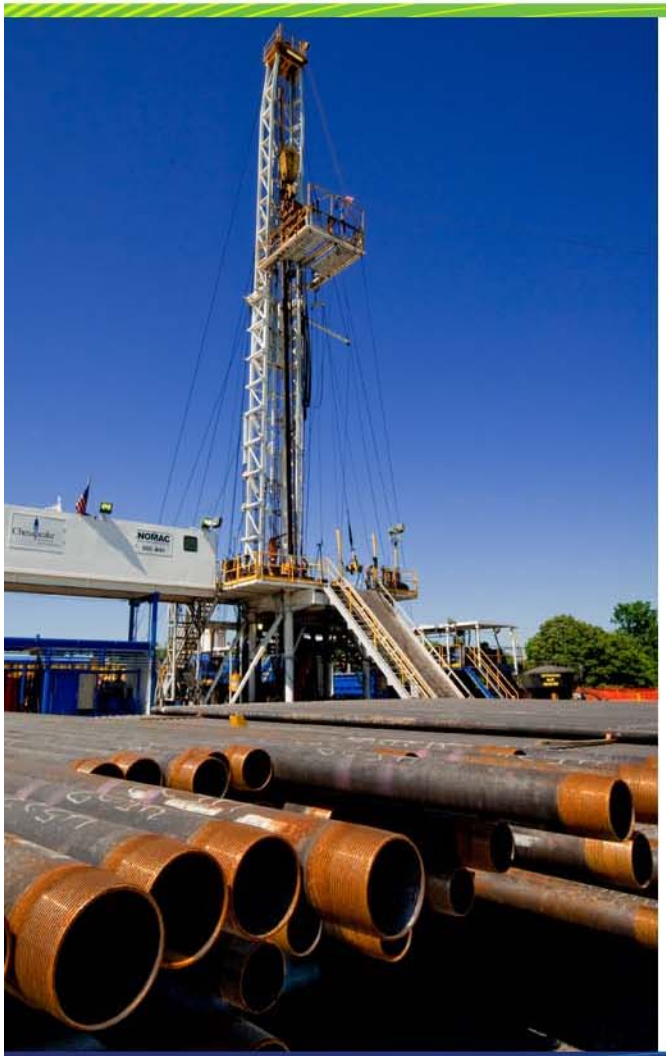
Joint Venture Strategy

- Apply cutting-edge geoscience technology, 3D seismic and petrophysical analysis to discover new prospect areas and define sweet spots. Enhance drilling and completion design to achieve play viability; transfer technology from other plays
- Unleash land machine to acquire large leasehold positions of 250,000 to 1 million net acres
- Bring in a JV partner for a minority interest in order to recapture virtually all acquisition costs, reduce risk and significantly fund future development



Creative and skillful use of people and technology has allowed CHK's Joint Venture Program to generate $12.8 billion of value in five transactions so far

Joint Venture Summary



- **CHK/PXP – July 2008**
  - Haynesville Shale (Louisiana, Texas): 80%/20%; 550,000 net acres; $30,000 per net undeveloped acre; $3.16 billion; 50% cash/50% carry
- **CHK/BP – September 2008**
  - Fayetteville Shale (Arkansas); 75%/25%; 540,000 net acres; $12,300 per net undeveloped acre; $1.9 billion; 58% cash/42% carry
- **CHK/STO – November 2008**
  - Marcellus Shale (New York, Pennsylvania, West Virginia); 67.5%/32.5%; 1.8 million net acres; $5,700 per net undeveloped acre; $3.375 billion; 37% cash/63% carry
- **CHK/TOT – January 2010**
  - Barnett Shale (Texas); 75%/25%; 270,000 net acres; $15,700 per net undeveloped acre; $2.25 billion; 36% cash/64% carry
- **CHK/CEO – Announced October 2010**
  - Eagle Ford Shale (Texas); 66.7%/33.3%; 600,000 net acres; $10,800 per net undeveloped acre; $2.16 billion; 50% cash/50% carry

CHK has earned its reputation as the U.S. partner of choice for international oil and natural gas companies

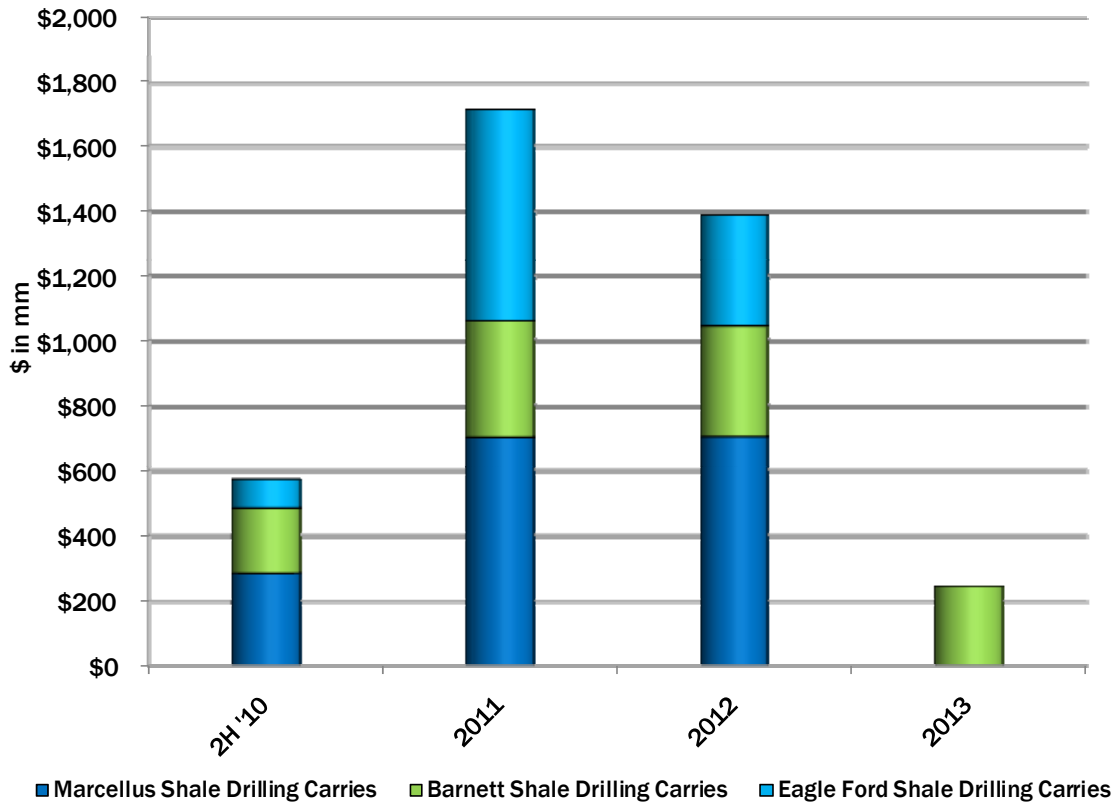
Enormous Value Creation Through JV Transactions

- CHK was early to recognize shale gas would become the biggest game changer in the past 50 years within the U.S. natural gas industry
- Initiated detailed shale science analysis and aggressive land acquisition program in late 2004
- Emerged with the best assets in the industry by 2008 and then sold off minority interests at a large profit to de-risk the plays
- The five transactions described below created $12.8 billion in immediate direct value and highlighted $37 billion of value in the interests CHK retained

$ in millions	Intial Payment	Drilling Carry	Total	Implied Value of Retained Properties
Plains Exploration (20% of the Haynesville)	$1,650	$1,510	$3,160	$13,200
BP America (25% of the Fayetteville)	1,100	800	1,900	5,700
Statoil USA (32.5% of the Marcellus)	1,250	2,125	3,375	7,000
Total S.A. (25% of the Barnett)	800	1,450	2,250	6,800
CNOOC Limited (33% of the Eagle Ford)	1,080	1,080	2,160	4,300
Total	$5,880	$6,965	$12,845	$37,000

Drilling Carry Schedule

- **From 3Q '10 through 3Q '13, CHK anticipates receiving ~$4.0 billion in drilling carries from Total, Statoil and CNOOC, a major asset not on our balance sheet**
  - Barnett: CHK pays 30% of drilling costs and earns a 75% WI due to the carry in the JV
  - Marcellus: CHK pays 17% of drilling costs and earns a 67.5% WI due to carry in the JV
  - Eagle Ford: CHK pays 17% of drilling costs and earns a 66.7% WI due to carry in the JV

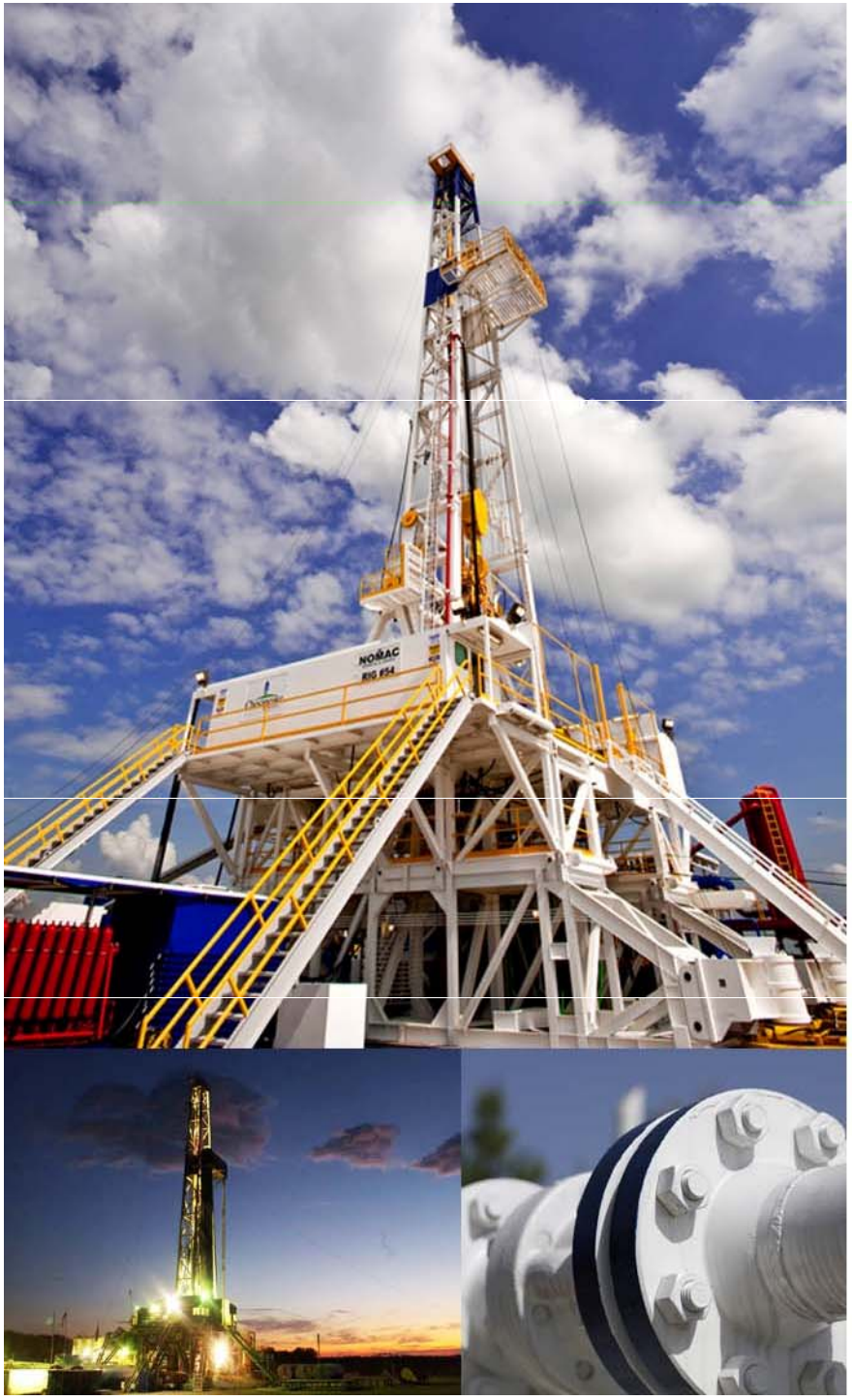


Shale Play Case Studies: CHK Strategy Has Produced Outstanding Returns

(As of 6/30/10, in millions)	Haynesville/ Bossier	Fayetteville	Marcellus	Barnett	Eagle Ford	Combined
Capital Invested						
Historical cost of buying acreage	($5,520)	($590)	($2,450)	($4,100)	($1,380)	($14,040)
Historical cost of drilling wells	(1,650)	(1,830)	(450)	(3,850)	($30)	(7,810)
Sub-total of total capital invested	**($7,170)**	**($2,420)**	**($2,900)**	**($7,950)**	**($1,410)**	**($21,850)**
Cash Inflows						
Cash flow from producing wells	$550	$830	$110	$2,040	$10	$3,540
Cash received from JV sale and leasehold promote	1,730	1,120	1,580	800	1,080	6,310
Cash received from drilling carries	1,510	800	400	300	-	3,010
Sub-total of cash inflows	**$3,790**	**$2,750**	**$2,090**	**$3,140**	**$1,090**	**$12,860**
Net cash inflow and invested capital	**($3,380)**	**$330**	**($810)**	**($4,810)**	**($320)**	**($8,990)**
Retained Asset Value						
PV10 of remaining drilling carries not in reserve report	-	-	$1,490	$420	$960	2,870
PV10 of proved reserves (10-yr strip @ 6/30/10)	$4,120	$3,360	1,120	4,230	$50	12,880
Value of unproved leasehold [1]	7,900	2,960	16,940	1,250	4,590	33,640
Sub-total	**$12,020**	**$6,320**	**$19,550**	**$5,900**	**$5,600**	**$49,390**
Total net cash flow and retained asset value	**$8,640**	**$6,650**	**$18,740**	**$1,090**	**$5,280**	**$40,400**
Return on investment	**221%**	**375%**	**746%**	**114%**	**475%**	**285%**
Proved reserves (bcfe)	2,916	2,404	462	2,895	25	8,702
Implied value of proved reserves based on PV10 ($/mcfe)	$1.41	$1.40	$2.42	$1.46	$1.84	$1.48
Total leasehold (acres)[2]	725,000	465,000	1,550,000	220,000	425,000	3,385,000
Total undeveloped leasehold (acres)[2]	670,000	370,000	1,540,000	125,000	425,000	3,130,000
Estimated value of unproved leasehold ($/acres)[1][3]	$11,800	$8,000	$11,000	$10,000	$10,800	$10,747

3:1 return on investment on $22 billion of invested capital!!!!

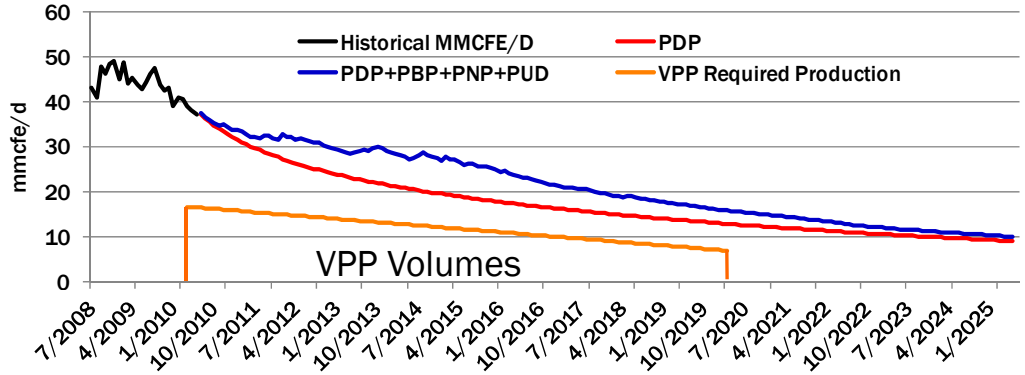
(1) Based on undeveloped unproved leasehold at the following rate per acre: Haynesville: $12,500, Bossier: $10,000, Fayetteville: $8,000 Marcellus: $11,000, Barnett: $10,000 and Eagle Ford: $10,800
(2) Haynesville and Bossier overlap in select areas of the play, combined acreage indicated to estimate value (Haynesville: 530,000 acres, Bossier: 195,000 acres). Eagle Ford acreage is pro forma for the CEO JV
(3) Based on 80-acre spacing, except Barnett at 60-acre spacing, at the following EUR per well: Haynesville: 6.5 bcfe, Bossier: 5.5 bcfe, Fayetteville: 2.6 bcfe, Marcellus: 5.25 bcfe, Barnett: 3.0 bcfe and Eagle Ford: 3.6 bcfe



Volumetric Production Payments (VPPs)

Benefits of Volumetric Production Payments (VPPs)

- A VPP is the sale of a term, overriding royalty interest on oil and natural gas properties; typically completely hedged and primarily PDP reserves



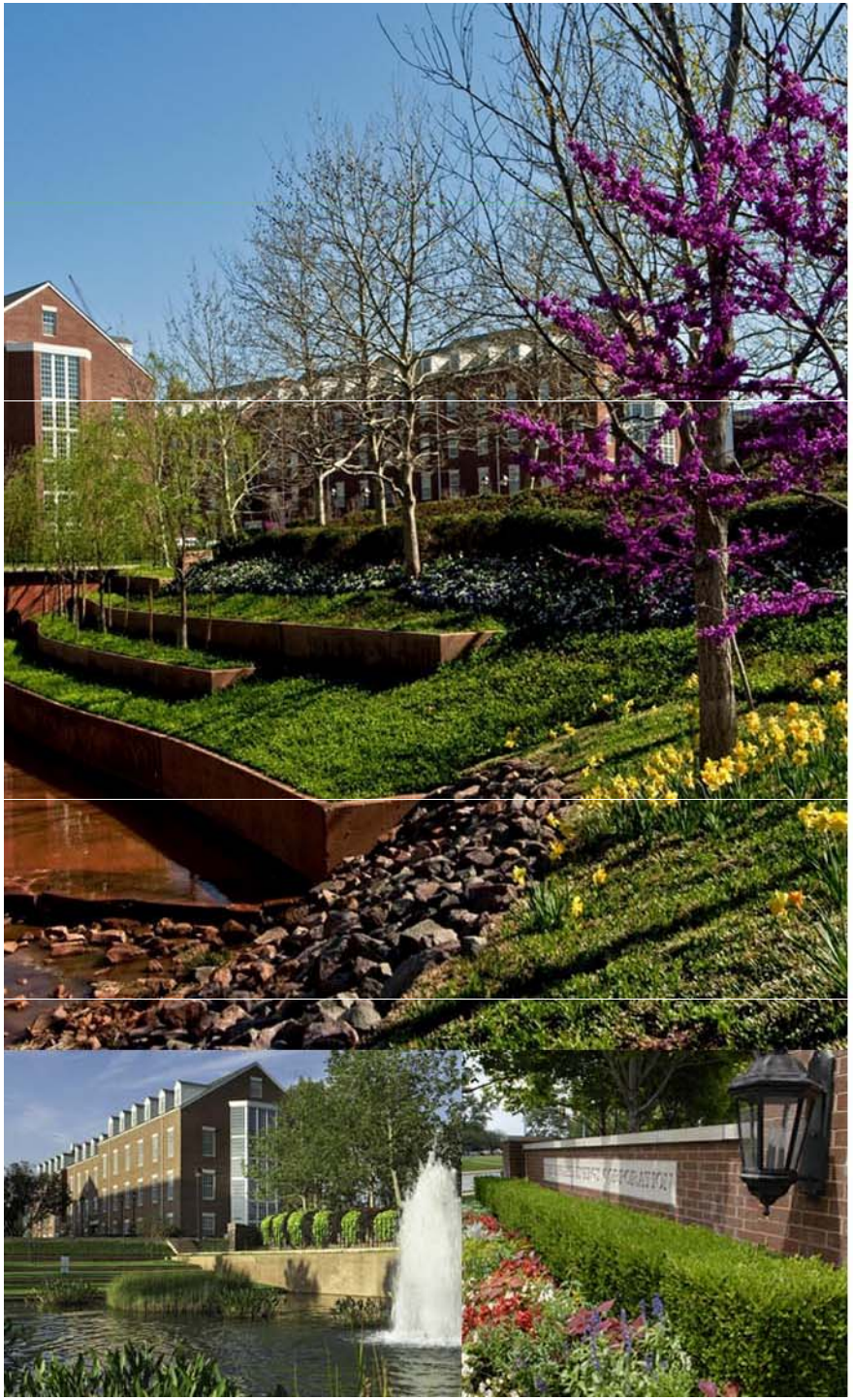
- Provides vehicle to accelerate cash flow from producing assets at an attractive discount rate
- High value per unit of production sold relative to traditional asset sale
- CHK retains the following:
  - Ownership and upside of the actual wellbores and leases
  - Excess production from VPP wellbores during the term of the VPP
  - Ownership of out-year production "tail"
  - PUD locations and in most cases, leasehold
- The VPP structure is tax-efficient
  - Sale treatment for GAAP reporting
    - — Debit cash; credit PP&E; production and resources removed
  - No capital gains tax
    - — Imputed interest deducted on consolidated tax return (treated as mortgage loan for tax purposes)

In summary, a VPP is a tax-advantaged sale of assets that provides the opportunity to retain all upside and receive value for contango in forward curves

CHK's VPPs to Date

CHK's VPP Summary	VPP1	VPP2	VPP3	VPP4	VPP5	VPP6	VPP7	VPP8	Total VPPs
Location	KY, WY	KS, OK, TX	OK	AR, OK	TX	LA, TX	NM, TX	TX	Various
Original term	15 years	11 years	11 years	8 years	7.5 years	10 years	10 years	5 years	5 - 15 years
Proceeds (millions)	$ 1,100	$ 622	$ 600	$ 413	$ 278	$ 180	$ 328	$ 1,146	$ 4,669
Quantity sold (bcfe)	208	94	93	98	68	46	38	391	$ 1,035
Netback price ($/mcfe)	$5.29	$6.60	$6.45	$4.20	$4.11	$3.95	$8.73	$2.93	$4.51

- Attractive financial tool to monetize production and reserves
- Tax-advantaged sale of assets
- Keep the tail and retain upside on the properties
- Another way to hedge and take advantage of the contango in the forward curve



CHK Hedging Strategy

Hedge Facility Overview

- **$15 billion mark-to-market ("MTM") capacity commitment from 13 different hedging counterparties**
- **~560,000 natural gas and oil price and basis contract capacity commitment**
  - Separate limits for oil and gas – linked to pledged collateral
  - Separate limits for price and basis - ~560,000 price and ~560,000 basis contracts
  - Equates to over 5 years of currently estimated future production
- **Trading capacity under the facility is based on aggregate and per-counterparty volume and MTM limitations**
  - Dual limitations clarify and limit counterparty credit exposure and clearly define trading capacity
    - Must pledge proved reserves valued at least 1.65x the current value of the covered trades
- **Pledge-to-play facility – must post reserves in order to have trading capacity**
  - In order for CHK to enter into 560,000 hedge contracts, we would have to post approximately that amount of proved reserves, 5.6 tcfe
  - Our total company proved reserves are ~16.1 tcfe[(1)(2)], so only 35% of our total proved reserves need to be pledged to the hedge facility
  - Projected proved reserves are growing at 2.5-3.5 tcfe per year, thus having adequate volumes for hedge facility is not an issue; same can be said for unencumbered proved reserves
- **Perpetual term, no expiration of core agreement**
  - In-line with a typical ISDA-based hedging relationship

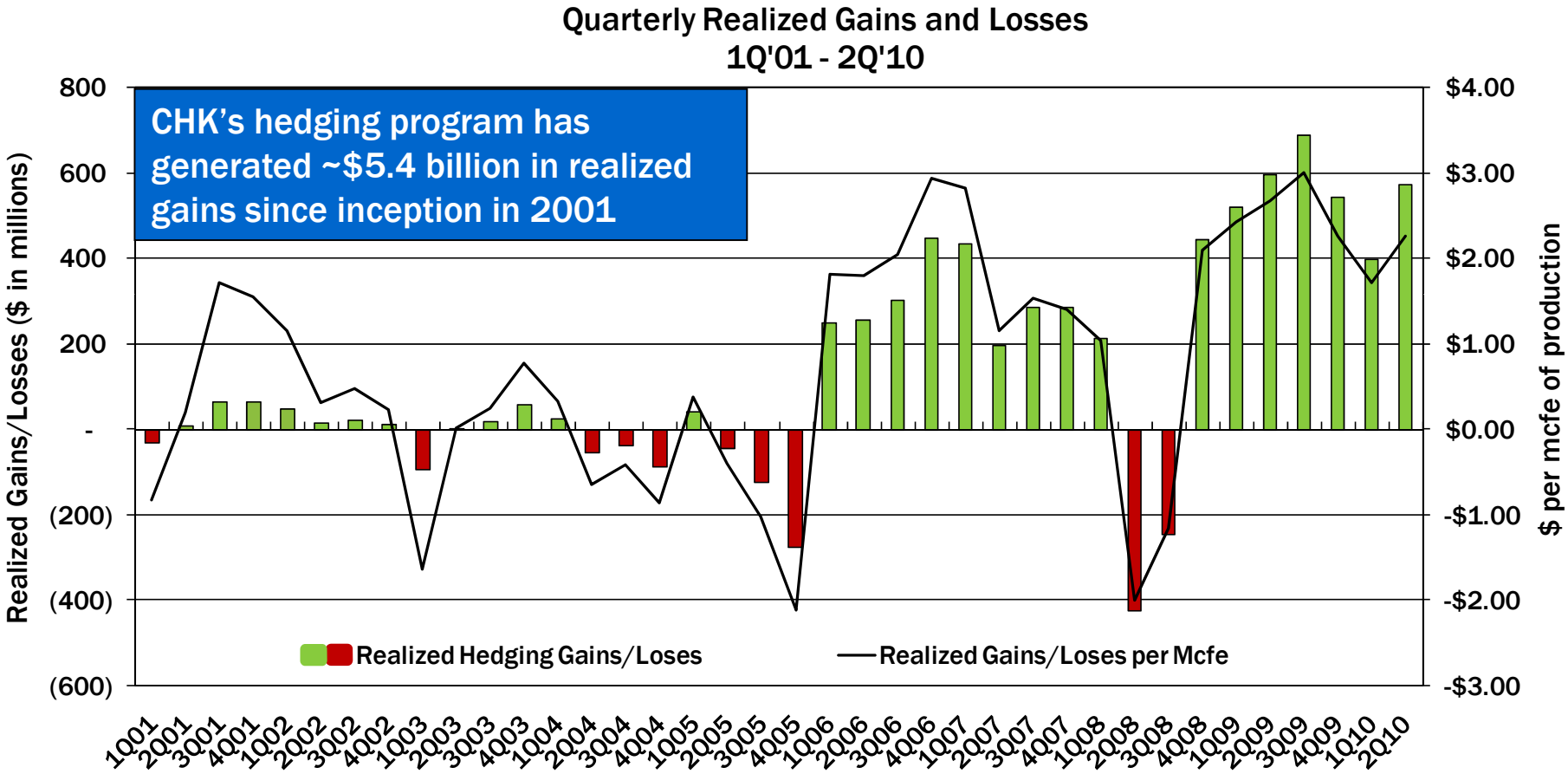
(1) Based on 10-Year average NYMEX strip pricing at 6/30/10; 15.5 tcfe using SEC pricing
(2) As of 6/30/10

Key Hedge Facility Features

- **Dedicated solely for commodity hedging**
  - No funded bank or bond investors whose interests may diverge from those of hedging counterparties
- **Preserve CHK's liquidity, greatly diminishing cash posting requirements**
- **Large size needed in order to be sufficient to our needs**
- **Significant flexibility and simplification in managing collateral and counterparties**
- **Right-way risk exposure for counterparties in the aggregate at all times**
  - Collateral value is highly correlated to the MTM valuation of CHK hedges
- **Significant benefits of cross-collateralization for counterparties**
  - Low probability that all counterparties will have concurrent "peak" exposures to CHK

CHK hedging program has made ~$5.4 billion in realized gains from 2001 - 1H'10

CHK Hedging: $5.4 Billion – Lucky or Good?



We don't hedge just to say we're hedged, we hedge to make money, have successfully done so 16 of past 18 quarters. That's not luck, that's skill!

CHK's Natural Gas and Oil Hedge Positions for 2H '10-2012[1][2]

Natural Gas Swaps[3]	% Hedged	NYMEX Avg. Price
2H '10E	51%	$7.58
2011E	50%	$6.74
2012E	2%	$6.50

Natural Gas Collars	% Hedged	Avg. Floor Price	Nymex Avg. Ceiling Price
2H '10E	2%	$7.60	$11.75
2011E	1%	$7.70	$11.50

Oil Swaps[4]	% Hedged	NYMEX Avg. Price
2H '10E	43%	$89.62
2011E	10%	$96.09
2012E	2%	$109.50

NYMEX Strip Prices @ 10/1/2010	Oil	Natural Gas
Remaining 2010	$77.39	$4.42
2011	$85.69	$4.43
2012	$88.35	$5.10
2013	$89.28	$5.33
2014	$89.98	$5.49
5-Year Average (2010-2014)	$86.14	$4.95

2011-12 Hedging Strategy:

Hedge offensively when opportunities present themselves as they have 3-4 times during the past 18 months

(1) Excludes written calls
(2) Assumes approximately the midpoint of company production forecast for each item and includes hedging positions as of 10/12/10
(3) Includes positions with knockout provisions for 1% of 2H 2010 natural gas production at knockout prices of $6.50 - $6.75/mcf and 2% of 2011 natural gas production at knockout prices of $5.75 - $6.50
(4) Includes positions with knockout provisions for 22%, 3% and 2% of 2H 2010, 2011 and 2012 oil production, respectively, at knockout prices of $60

Updated Outlook/Guidance

New Outlook Summary

As of 10/12/10 Outlook

	2010	2011	2012	2-year Change
Production				
Natural gas - bcf	898 - 918	990 - 1,010	1,086 - 1,130	22%
Oil and NGL's - mbbls	19,000	32,000 - 36,000	38,000 - 44,000	116%
Natural gas equivalent - bcfe	1,012 - 1,032	1,182 - 1,226	1,314 - 1,394	32%
Daily natural gas equivalent midpoint - mmcfe	2,800	3,300	3,700	32%
YOY estimated production increases	12 - 14%	16 - 20%	9 - 15%	
YOY estimated production increases excluding asset sales	20 - 22%	19 - 23%	10 - 16%	
Operating costs per mcfe				
LOE, production taxes and G&A[1]	$1.40 - $1.60	$1.40 - $1.60	$1.40 - $1.60	0%
Operating cash flow ($mm)[2][3]	$4,800 - $4,900	$4,900 - $5,300	$4,900 - $5,700	9%
Drilling and completion costs, net of JV carries ($mm)	($4,500) - ($4,600)	($4,500) - ($4,600)	($4,500) - ($4,600)	Flat

Growing production more than 30% from 2010 – 12 without increasing drilling capex; 40% of this growth will come from increased liquids production

1) Excluding stock based compensation
2) Operating cash flow before changes in assets and liabilities. This is a non-GAAP financial measure. We are unable to provide a 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 of $4.00 to $5.00 per mcf and $75.00 per bbl in 2010, $4.00 to $5.00 per mcf and $80.00 per bbl in 2011 and $5.00 to $6.00 per mcf and $80.00 per bbl in 2012

2010 Financial Projections at Various Natural Gas Prices

As of 10/12/10 Outlook

($ in millions; oil at $76.99 NYMEX)	$4.00	$5.00	$6.00	$7.00
O/G revenue (unhedged) @ 1,022 bcfe[1]	$4,450	$4,580	$4,700	$4,830
Hedging effect[2]	2,010	1,940	1,870	1,810
Marketing and other (@ $0.13/mcfe)	130	130	130	130
Production taxes 5%	(220)	(230)	(230)	(240)
LOE (@ $0.90/mcfe)	(920)	(920)	(920)	(920)
G&A (@ $0.43/mcfe)[3]	(430)	(430)	(430)	(430)
Ebitda	**5,020**	**5,070**	**5,120**	**5,180**
Interest (@ $0.18/mcfe)[4]	(180)	(180)	(180)	(180)
Operating cash flow[2][3][5]	**4,840**	**4,890**	**4,940**	**5,000**
Oil and gas depreciation (@ $1.45/mcfe)	(1,480)	(1,480)	(1,480)	(1,480)
Depreciation of other assets (@ $0.23/mcfe)	(230)	(230)	(230)	(230)
Income taxes (38.5% rate)	(1,210)	(1,220)	(1,240)	(1,270)
Net income to common[1]	**$1,920**	**$1,960**	**$1,990**	**$2,020**
Net income to common per fully diluted shares	$2.71	$2.77	$2.81	$2.86
Net debt/ebitda[6]	2.1	2.1	2.1	2.1
Debt to book capitalization ratio	40%	40%	40%	39%
Ebitda/fixed charges (including pfd. dividends)[7]	6.7	6.7	6.8	6.9
MEV/operating cash flow[8]	**3.4x**	**3.4x**	**3.4x**	**3.3x**
EV/ebitda[9]	**5.9x**	**5.8x**	**5.8x**	**5.7x**
PE ratio[10]	**8.1x**	**7.9x**	**7.8x**	**7.7x**

1) Before effects of unrealized hedging gain or loss
2) Includes the non-cash effect of lifted hedges and financing derivatives
3) Includes charges related to stock based compensation
4) Pro forma debt redemptions $2.1 billion; debt offering of 2.0 billion
5) Before changes in assets and liabilities
6) Net Debt = long-term debt less cash
7) Fixed charges ($754 mm) = interest expense of $639 million plus preferred dividends of $115 million
8) MEV (Market Equity Value) = $16.7 billion ($22.00/share x 758 mm fully diluted shares as of 6/30/10)
9) EV (Enterprise Value) = $29.6 billion (Market Equity Value, plus $10.7 billion in net long-term debt plus $2.2 billion working capital deficit)
10) Assuming a common stock price of $22.00/share

2011 Financial Projections at Various Natural Gas Prices

As of 10/12/10 Outlook

($ in millions; oil at $80.00 NYMEX)	$4.00	$5.00	$6.00	$7.00
O/G revenue (unhedged) @ 1,204 bcfe[1]	$5,410	$6,230	$7,060	$7,880
Hedging effect[2]	1,460	1,040	610	160
Marketing and other (@ $0.13/mcfe)	160	160	160	160
Production taxes 5%	(270)	(310)	(350)	(390)
LOE (@ $0.90/mcfe)	(1,080)	(1,080)	(1,080)	(1,080)
G&A (@ $0.43/mcfe)[3]	(510)	(510)	(510)	(510)
Ebitda	**5,170**	**5,530**	**5,890**	**6,220**
Interest (@ $0.23/mcfe)[4]	(270)	(270)	(270)	(270)
Operating cash flow[2][3][5]	**4,900**	**5,260**	**5,620**	**5,950**
Oil and gas depreciation (@ $1.45/mcfe)	(1,750)	(1,750)	(1,750)	(1,750)
Depreciation of other assets (@ $0.23/mcfe)	(270)	(270)	(270)	(270)
Income taxes (38.5% rate)	(1,110)	(1,250)	(1,390)	(1,510)
Net income to common[1]	**$1,770**	**$1,990**	**$2,210**	**$2,420**
Net income to common per fully diluted shares	$2.35	$2.64	$2.94	$3.22
Net debt/ebitda[6]	2.1	1.9	1.8	1.7
Debt to book capitalization ratio	35%	35%	35%	35%
Ebitda/fixed charges (including pfd. dividends)[7]	6.7	7.2	7.7	8.1
MEV/operating cash flow[8]	**3.4x**	**3.2x**	**3.0x**	**2.8x**
EV/ebitda[9]	**5.7x**	**5.4x**	**5.0x**	**4.8x**
PE ratio[10]	**9.4x**	**8.3x**	**7.5x**	**6.8x**

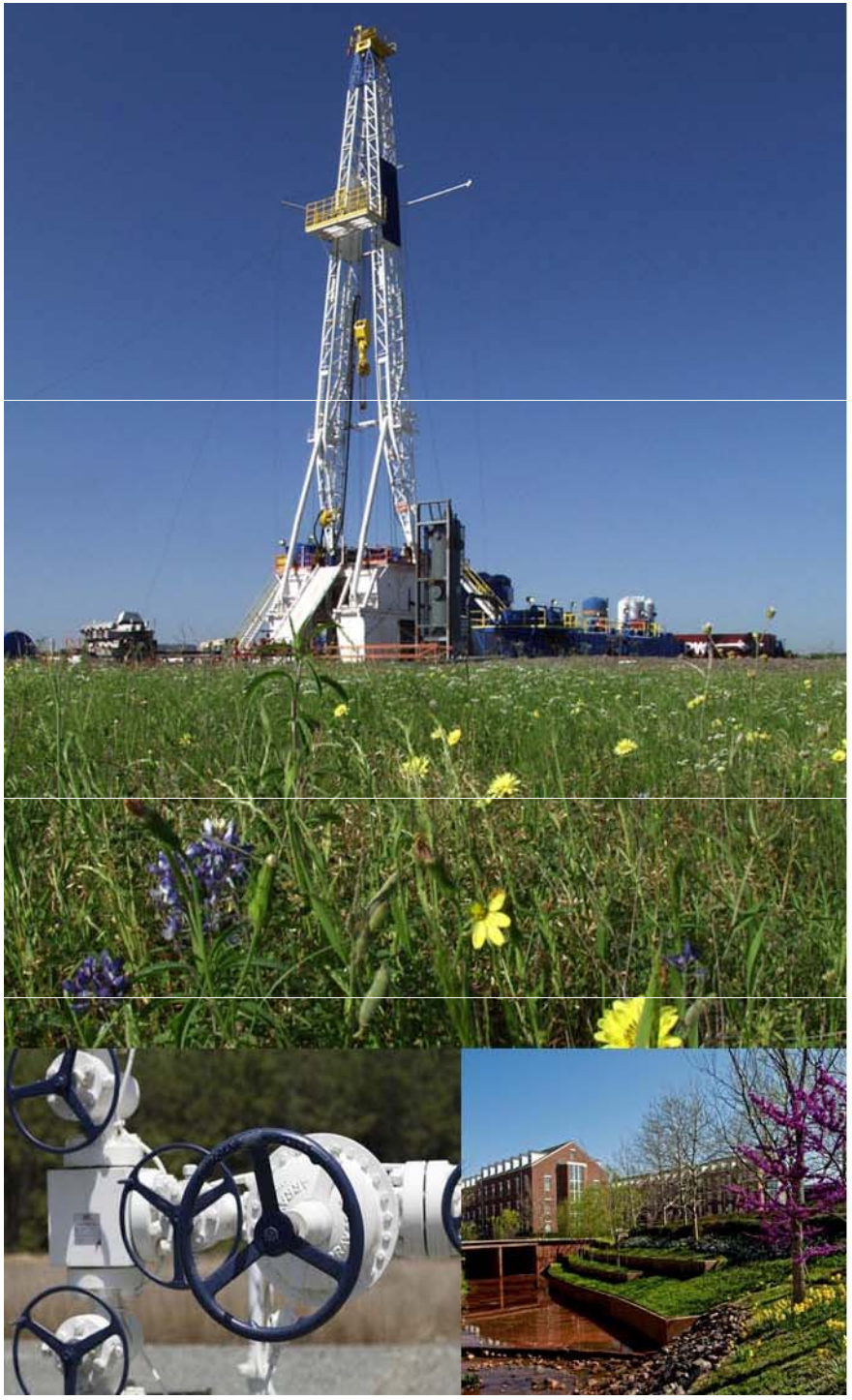
1) Before effects of unrealized hedging gain or loss
2) Includes the non-cash effect of lifted hedges and financing derivatives
3) Includes charges related to stock based compensation
4) Pro forma debt redemptions $2.1 billion; debt offering of 2.0 billion
5) Before changes in assets and liabilities
6) Net Debt = long-term debt less cash
7) Fixed charges ($767 mm) = interest expense of $595 million plus preferred dividends of $172 million
8) MEV (Market Equity Value) = $16.7 billion ($22.00/share x 758 mm fully diluted shares as of 6/30/10)
9) EV (Enterprise Value) = $29.6 billion (Market Equity Value, plus $10.7 billion in net long-term debt plus $2.2 billion working capital deficit)
10) Assuming a common stock price of $22.00/share

2012 Financial Projections at Various Natural Gas Prices

As of 10/12/10 Outlook

($ in millions; oil at $80.00 NYMEX)	$4.00	$5.00	$6.00	$7.00
O/G revenue (unhedged) @ 1,354 bcfe[1]	$6,200	$7,110	$8,030	$8,940
Hedging effect[2]	60	50	30	(50)
Marketing and other (@ $0.13/mcfe)	180	180	180	180
Production taxes 5%	(310)	(360)	(400)	(450)
LOE (@ $0.90/mcfe)	(1,220)	(1,220)	(1,220)	(1,220)
G&A (@ $0.43/mcfe)[3]	(580)	(580)	(580)	(580)
Ebitda	**4,330**	**5,180**	**6,040**	**6,820**
Interest (@ $0.23/mcfe)[4]	(300)	(300)	(300)	(300)
Operating cash flow[2][3][5]	**4,030**	**4,880**	**5,740**	**6,520**
Oil and gas depreciation (@ $1.45/mcfe)	(1,960)	(1,960)	(1,960)	(1,960)
Depreciation of other assets (@ $0.23/mcfe)	(300)	(300)	(300)	(300)
Income taxes (38.5% rate)	(680)	(1,010)	(1,340)	(1,640)
Net income to common[1]	**$1,090**	**$1,610**	**$2,140**	**$2,620**
Net income to common per fully diluted shares	$1.44	$2.12	$2.82	$3.45
Net debt/ebitda[6]	2.5	2.1	1.8	1.6
Debt to book capitalization ratio	33%	33%	32%	32%
Ebitda/fixed charges (including pfd. dividends)[7]	5.6	6.8	7.9	8.9
MEV/operating cash flow[8]	**4.1x**	**3.4x**	**2.9x**	**2.6x**
EV/ebitda[9]	**6.8x**	**5.7x**	**4.9x**	**4.3x**
PE ratio[10]	**15.3x**	**10.4x**	**7.8x**	**6.4x**

1) Before effects of unrealized hedging gain or loss
2) Includes the non-cash effect of lifted hedges
3) Includes charges related to stock based compensation
4) Pro forma debt redemptions $2.1 billion; debt offering of 2.0 billion
5) Before changes in assets and liabilities
6) Net Debt = long-term debt less cash
7) Fixed charges ($767 mm) = interest expense of $595 million plus preferred dividends of $172 million
8) MEV (Market Equity Value) = $16.7 billion ($22.00/share x 758 mm fully diluted shares as of 6/30/10)
9) EV (Enterprise Value) = $29.6 billion (Market Equity Value, plus $10.7 billion in net long-term debt plus $2.2 billion working capital deficit)
10) Assuming a common stock price of $22.00/share



CHK Value Proposition

What Are Unproved Resources and Unproved Acreage Worth Today?

Play Areas	Total Net Acreage[1]	Unproved Net Acreage	Unrisked Time Adjusted Estimated Value/Acre @ $6.00 Gas	Unrisked Unproved Time Adjusted Acreage Value @ $6.00 Gas ($ in bln)	Risk Factor	Risked Unproved Resources (tcfe)	Risked Time Adjusted Estimated Value/Acre @ $6.00 Gas	Risked Unproved Resources ($/mcfe)	Risked Unproved Time Adjusted Acreage Value @ $6.00 Gas ($ in bln)
Marcellus Shale[2]	1,550,000	1,541,000	$27,900	$43.1	60%	34.4	$11,200	$0.50	$17.2
Haynesville Shale[2]	530,000	476,000	$20,700	$9.9	30%	19.7	$14,500	$0.35	$6.9
Barnett Shale[3]	220,000	124,000	$9,800	$1.2	15%	3.4	$8,300	$0.30	$1.0
Fayetteville Shale[3]	465,000	370,000	$9,900	$3.7	20%	7.7	$7,900	$0.38	$2.9
Bossier Shale[2][4]	195,000	195,000	$11,500	$2.2	60%	4.0	$4,600	$0.22	$0.9
Granite Wash[3]	200,000	157,000	$51,000	$8.0	25%	5.7	$38,200	$1.05	$6.0
Other Unconv. Liquids	2,655,000	2,615,000	$14,300	$37.3	65%	16.4	$4,600	$0.73	$11.9
Other	8,320,000	6,040,000	$1,500	$9.1	75%	8.0	$400	$0.28	$2.3
Total @ $6.00 Gas	13,940,000	11,322,000	$10,100	$114.4	65%	99.3	$4,300	$0.50	$49.2
Total Value @:									
$4.00 Gas			$5,700/acre				$2,200/acre	$0.26	$26.1
$5.00 Gas			$6,700/acre				$2,800/acre	$0.32	$32.1
$7.00 Gas			$13,000/acre				$5,800/acre	$0.67	$66.3
$8.00 Gas			$16,100/acre				$7,300/acre	$0.84	$83.4

(1) As of 6/30/10
(2) Based on 10-year PV10 economic development assumption
(3) Based on a 5-year PV10 economic development assumption
(4) Not included in total due to overlap in Haynesville Shale acreage

CHK Net Asset Value

	6/30/2010 pro forma[1] NAV @ various NYMEX natural gas prices[2]			
($ in millions, except per share data)	$4.00	$5.00	$6.00	$7.00
Proved reserves	$ 12,300	$ 18,200	$ 24,300	$ 30,500
Unproved resources[3]	26,100	32,100	49,200	66,300
Value of CHK hedges[4]	2,000	1,500	1,000	(200)
Midstream assets[5]	2,900	2,900	2,900	2,900
Other assets[6]	3,500	3,500	3,500	3,500
STO and TOT: PV of future drilling carries[7]	1,900	1,900	1,900	1,900
Less: long-term debt (net of cash equivalents)[1]	(10,700)	(10,700)	(10,700)	(10,700)
Less: preferred stock (when not dilutive)	(300)	-	-	-
Less: net working capital	(2,200)	(2,200)	(2,200)	(2,200)
Shareholder value	$ 35,500	$ 47,200	$ 69,900	$ 92,000
Fully diluted common shares (in millions)[8]	752	758	758	758
NAV per share	$ 47.21	$ 62.27	$ 92.22	$ 121.37
Potential % upside[8]	115%	183%	319%	452%
Asset value to long-term debt	4.3x	5.4x	7.5x	9.6x

Compelling risk-reward proposition

NYMEX Strip Prices @ 10/1/2010	Oil	Natural Gas
2010	$77.39	$4.42
2011	$85.69	$4.43
2012	$88.35	$5.10
2013	$89.28	$5.33
2014	$89.98	$5.49
5-Year Average (2010-14)	$86.14	$4.95

1) As of 6/30/10; pro forma for debt redemptions/repurchases of $2.1 billion and senior note debt issuances of $2.0 billion
2) NYMEX gas price changes and NYMEX oil price held constant at $80.00 per bbl
3) 99.3 tcfe of unproved resources, see page 29 for valuation approach
4) Outlook issued on 10/12/10
5) CMD assets based on net book value and CHKM assets based on $25.00 per unit
6) Building, drilling rigs, other assets at net book value and investments at market value
7) Excludes existing carries included in proved reserve report above
8) Based on common stock price of $22.00 per share

CHK: Positioned for Success in 2H 2010 and Beyond

- **Great Assets**
  - Largest leasehold position in the best U.S. onshore natural gas shale plays
  - 2.9 mm net acres of new leasehold targeting liquids-rich plays
- **Great Reserves/Resources**
  - Decades of development drilling at low drilling and completion costs
  - 16.1 tcfe of proved resources (22-24 tcfe by 2012)(1)
  - 99 tcfe risked unproved resources (69 tcfe from natural gas shale plays, 3.7 billion boe from liquids-rich plays, 8 tcfe from conventional plays)
- **Innovative Joint Ventures**
  - World-class partners (BP, PXP, STO, TOT and CEO) with $4 billion of future JV carries
  - Sold assets for $12.8 billion, retained remaining JV assets valued by third-parties at ~$37 billion
  - Further JVs and asset monetizations on the way
- **Well Structured Balance Sheet**
  - Staggered long-term maturity structure and only $500 mm of senior notes due by February 2015
- **Attractive Valuation**
  - Trade at a substantial discount to estimated NAV and way below single shale play companies
- **Still Growing Strong**
  - Anticipate reporting production growth of ~13% in 2010, ~18% in 2011 and ~12% in 2012; liquids production growth expected of 60% in 2010, 80% in 2011 and 20% in 2012

The NAV value gap won't last forever!

Data above incorporates:
- CHK's press release and Outlook dated 10/12/10
- Risk disclosures regarding unproved resource estimates on page iii of the presentation package

1) Based on 10-Year average NYMEX strip pricing at 6/30/2010; 15.5 tcfe of proved reserves using SEC pricing