APRIL 2013
INVESTOR PRESENTATION

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 are statements other than those of historical fact that give our current expectations or forecasts of future events. They include estimates of our natural gas and liquids reserves, expected natural gas and liquids production and future expenses, estimated operating costs, assumptions regarding future natural gas and liquids prices, effects of anticipated asset sales, planned drilling activity and drilling and completion capital expenditures (including the use of joint venture drilling carries), and other anticipated cash outflows, as well as projected cash flow and liquidity, debt reduction, 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, and such market prices are subject to significant volatility. Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Reference to the Utica EUR per well average (estimated ultimate recovery) of natural gas and oil includes amounts that are not yet classified as proved reserves under SEC definitions, but that we believe will ultimately be produced. 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. 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.
- Pending sales transactions are subject to closing conditions and may not be completed in the time frame anticipated. We do not have binding agreements for all of our planned asset sales. Our ability to consummate each of these transactions is subject to changes in market conditions and other factors. If one or more of the transactions is not completed in the anticipated time frame or at all or for less proceeds than anticipated, our ability to fund budgeted capital expenditures and reduce our indebtedness as planned could be adversely affected. For sale transactions that have closed, we may not be able to satisfy all the requirements necessary to receive proceeds subject to title and other contingencies.
- Factors that could cause actual results to differ materially from expected results are described in Item 1A "Risk Factors" in our 2012 Form 10-K filed with the U.S. Securities and Exchange Commission on March 1, 2013 . These risk factors include the volatility of natural gas, oil and NGL prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the values of our natural gas and liquids properties resulting in ceiling test write-downs; the availability of capital on an economic and timely basis, including planned asset sales, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas and liquids 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, oil and NGL sales and the need to secure hedging liabilities; drilling and operating risks, including potential exposure to environmental liabilities; legislative and regulatory actions or changes adversely affecting our industry and our business; general economic conditions negatively impacting us and our business counterparties; oilfield services shortages, pipeline and gathering system capacity constraints and transportation interruptions that could adversely affect our cash flow; losses possible in pending or future litigation and governmental proceedings; and cyber attacks targeting our systems and infrastructure adversely impacting our operations.
- Although we believe the expectations and forecasts reflected in forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate or changed assumptions or by known or unknown risks and uncertainties. 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.

INDUSTRY LEADERSHIP

- 2nd largest U.S. natural gas producer (net), ~4% of total
- Largest U.S. natural gas producer (gross), ~9% of total
- 11th largest U.S. liquids (oil and NGL) producer
- #1 driller of horizontal shale wells in the world
- Largest U.S. leasehold and 3D seismic owner
- #1 inventory of shale core data and industry's only proprietary Reservoir Technology Center
- Discovered Haynesville Shale, Utica, Powder River Niobrara, Tonkawa and Mississippi Lime unconventional plays – industry’s best record of unconventional exploration success

CHK has captured the largest U.S. oil and natural gas resource bases and is now working to deliver value to its shareholders

4Q ’12 EARNINGS SUMMARY

- **Production results**
  - 4Q ’12 total production averaged 3.931 bcfe/d, up 9% YOY
  - 4Q ’12 liquids production of ~147,500 bbls/d, up 39% YOY
    - Oil production grew 69% YOY
- **Liquids 23% of total production and 62% of realized revenue during 4Q’12**
- **Financial performance**
  - ~$1.1 billion of adjusted ebidta[1]
  - ~$1.1 billion operating cash flow[1]
  - $153 mm of adjusted net income available to common stockholders[1]
    - $0.26 per fully diluted common share
  - Production costs decreased 6% YOY from $0.88/mcfe to $0.83/mcfe
  - G&A costs decreased 34% YOY from $0.35/mcfe to $0.23/mcfe
- **YE’12 proved reserves total 15.7 tcfe using SEC trailing 12-month avg. and 19.6 tcfe using 10-year avg. NYMEX strip**
  - Added new net proved reserves of 5.0 tcfe through the drillbit at a drilling and completion cost of $10.92/boe

(1) Reconciliations of non-GAAP financial measures to comparable GAAP measures appear on pages 32-34

We look forward to completing a successful year of asset sales, liquids-focused production growth and debt reduction, while also improving capital efficiency

CURRENT OBJECTIVES AND INITIATIVES

- **Improving production mix towards more liquids**
  - Aiming for ~27% liquids production growth in 2013 to reach ~26% of total production as liquids[1]
- **Reducing per unit production and G&A costs**
- **Achieving targeted capital budget reductions**
  - Large leasehold, midstream and oilfield services expenditures are no longer required to drive value creation
- **Increasing operational excellence**
  - Creating impactful efficiency gains by focusing drilling in the "core of the core"
  - Improving capital efficiency
    - Shifting focus from acreage capture to resource development
    - Leveraging economies of scale from pad drilling
- **Monetizing noncore assets**
  - Targeting $4-7 billion of asset sales in 2013
    - Announced ~$1.0 billion JV in Mississippi Lime with Sinopec
- **Reducing financial leverage and enhancing liquidity**
  - Ended 2012 with more than $4.0 billion in available liquidity

(1) Estimate per 2/21/2013 Outlook

The task now at hand is to convert a decade of industry-leading new play investments into improved shareholder returns

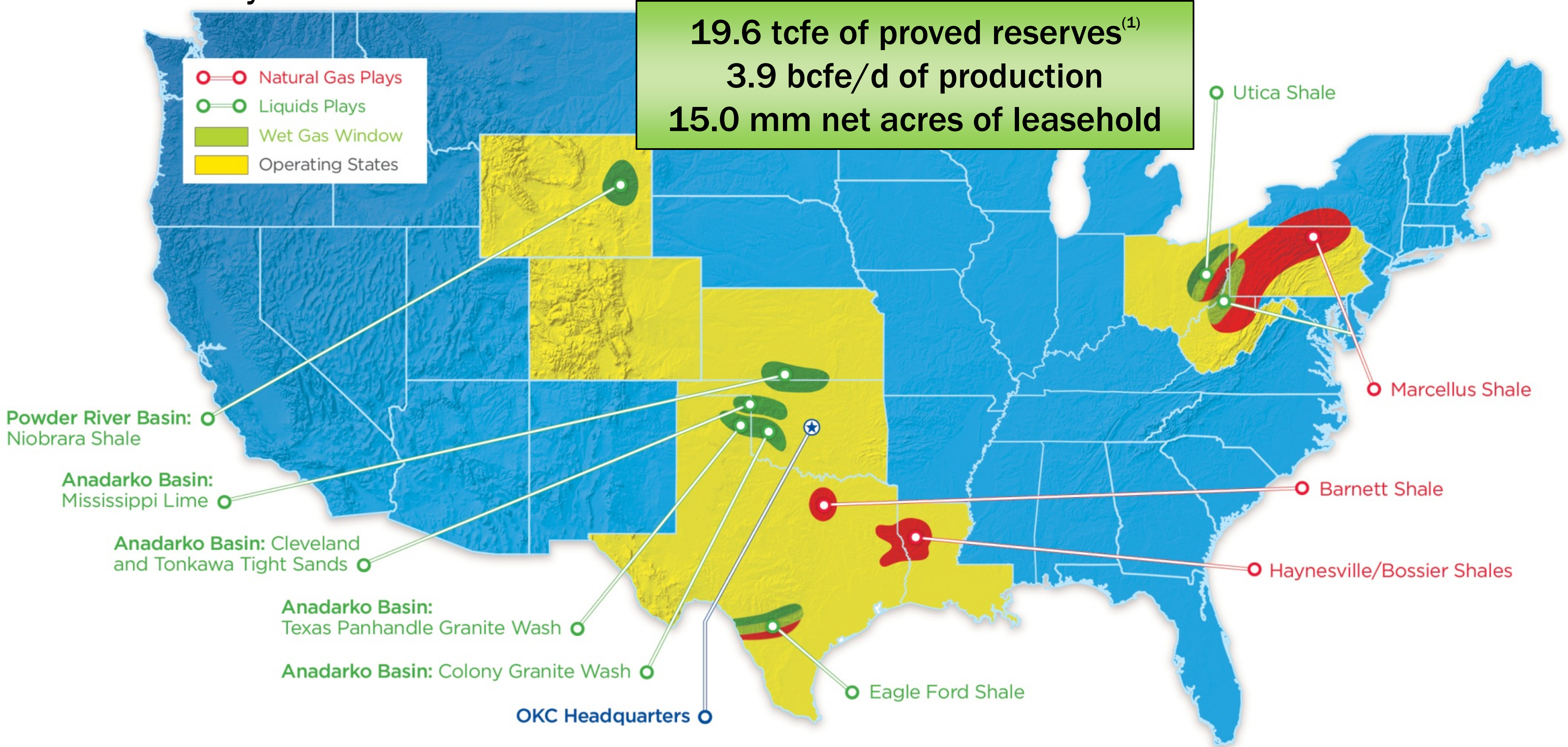
PREMIER COLLECTION OF U.S. E&P ASSETS

Chesapeake ENERGY

FOCUSED ON 10 KEY PLAYS

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

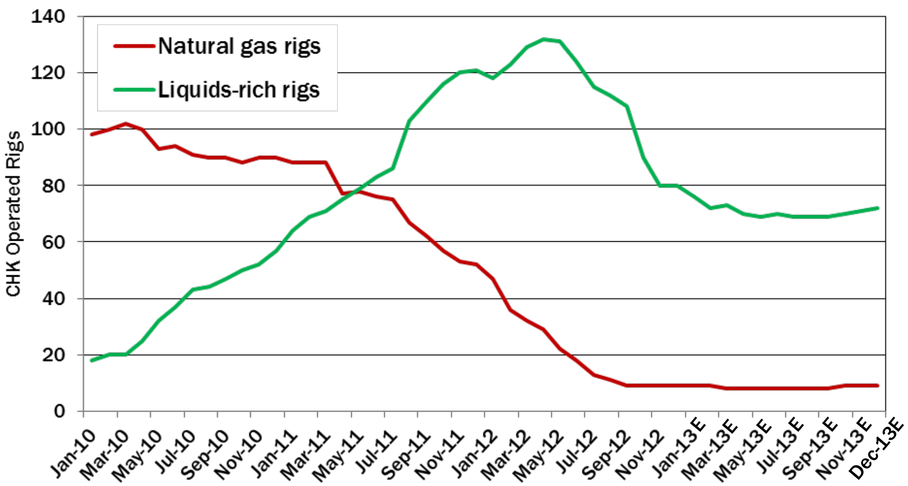
19.6 tcfe of proved reserves[1]
3.9 bcfe/d of production
15.0 mm net acres of leasehold

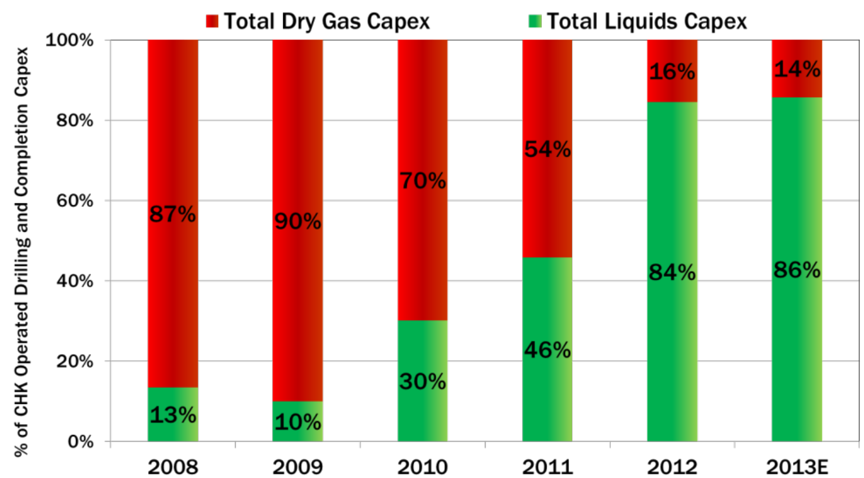


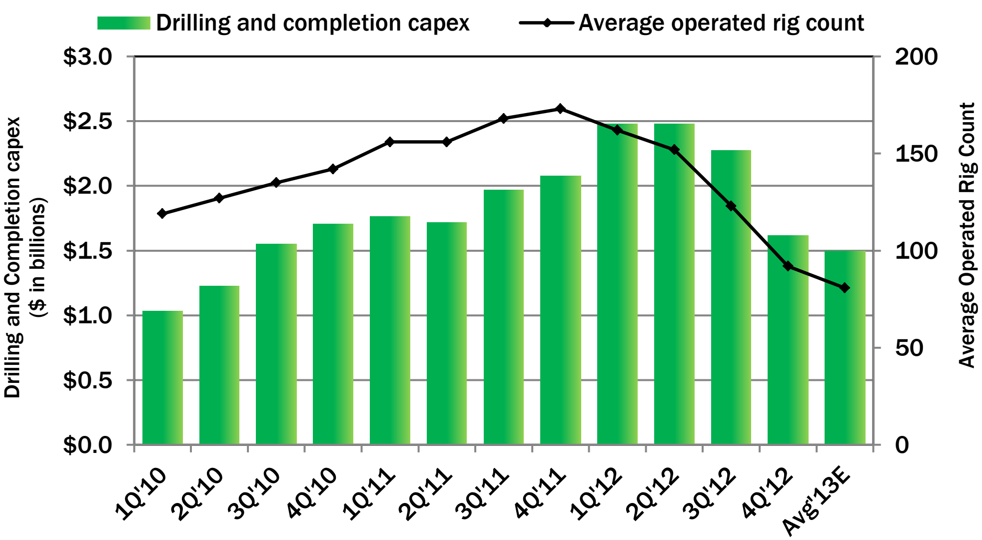
(1) Based on 10-year average NYMEX strip prices as of 12/31/12; 15.7 tcfe based on SEC pricing

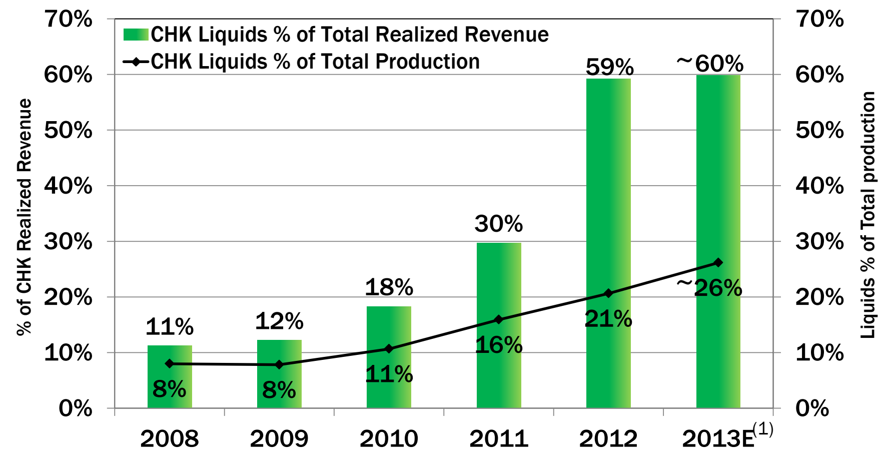
Nearly exclusive focus on the "core of the core" in 10 leading plays, in all of which CHK has a #1 or #2 position

AGGRESSIVE SHIFT OF CAPITAL TO LIQUIDS-RICH PLAYS HAS PAID OFF







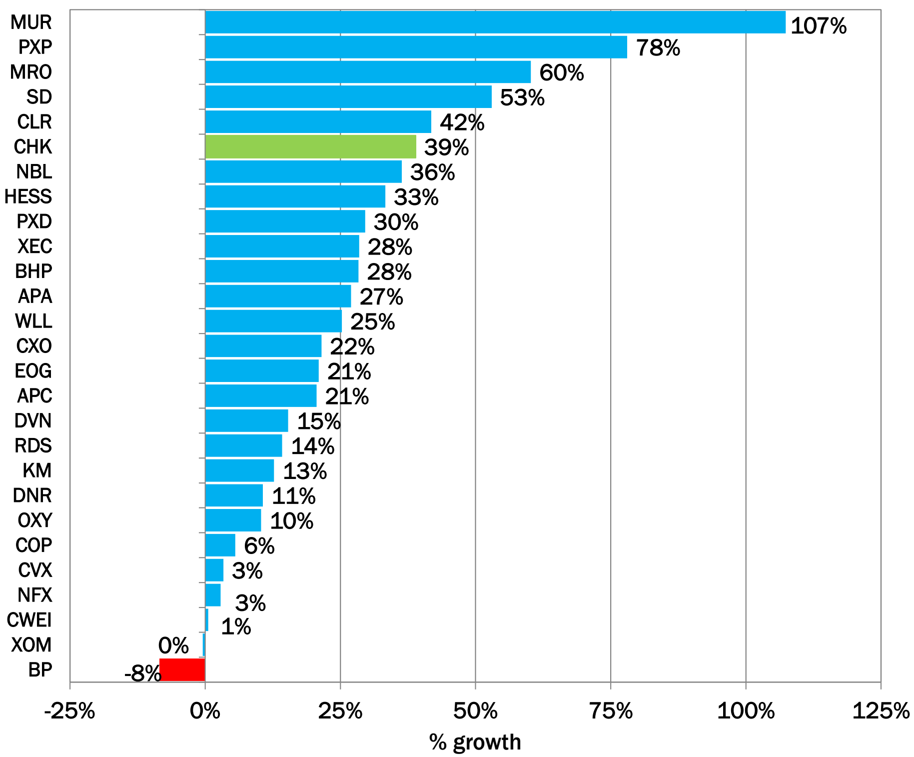


(1) Assumes NYMEX natural gas and oil prices of $3.75/mcf and $95/bbl in 2013

CHK has been very responsive to market signals and aggressively shifted to higher return liquids-rich plays and moderated spending due to reduced cash flow

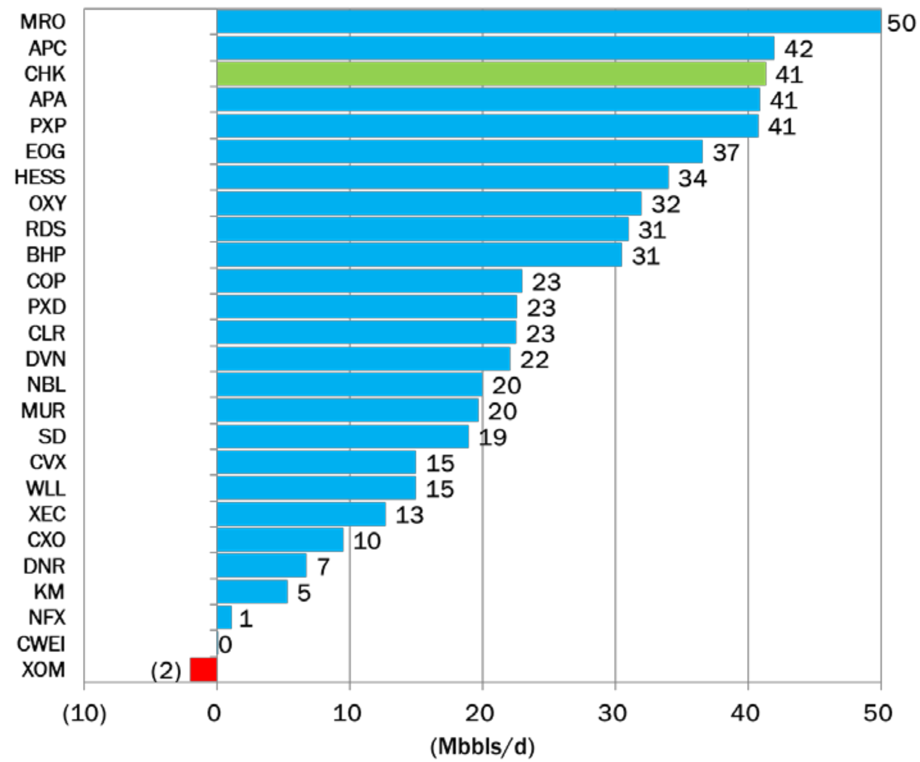
ONE OF THE BEST U.S. LIQUIDS GROWTH STORIES IN THE INDUSTRY

YOY Percentage Growth



4Q'11 - 4Q'12

YOY Absolute Growth



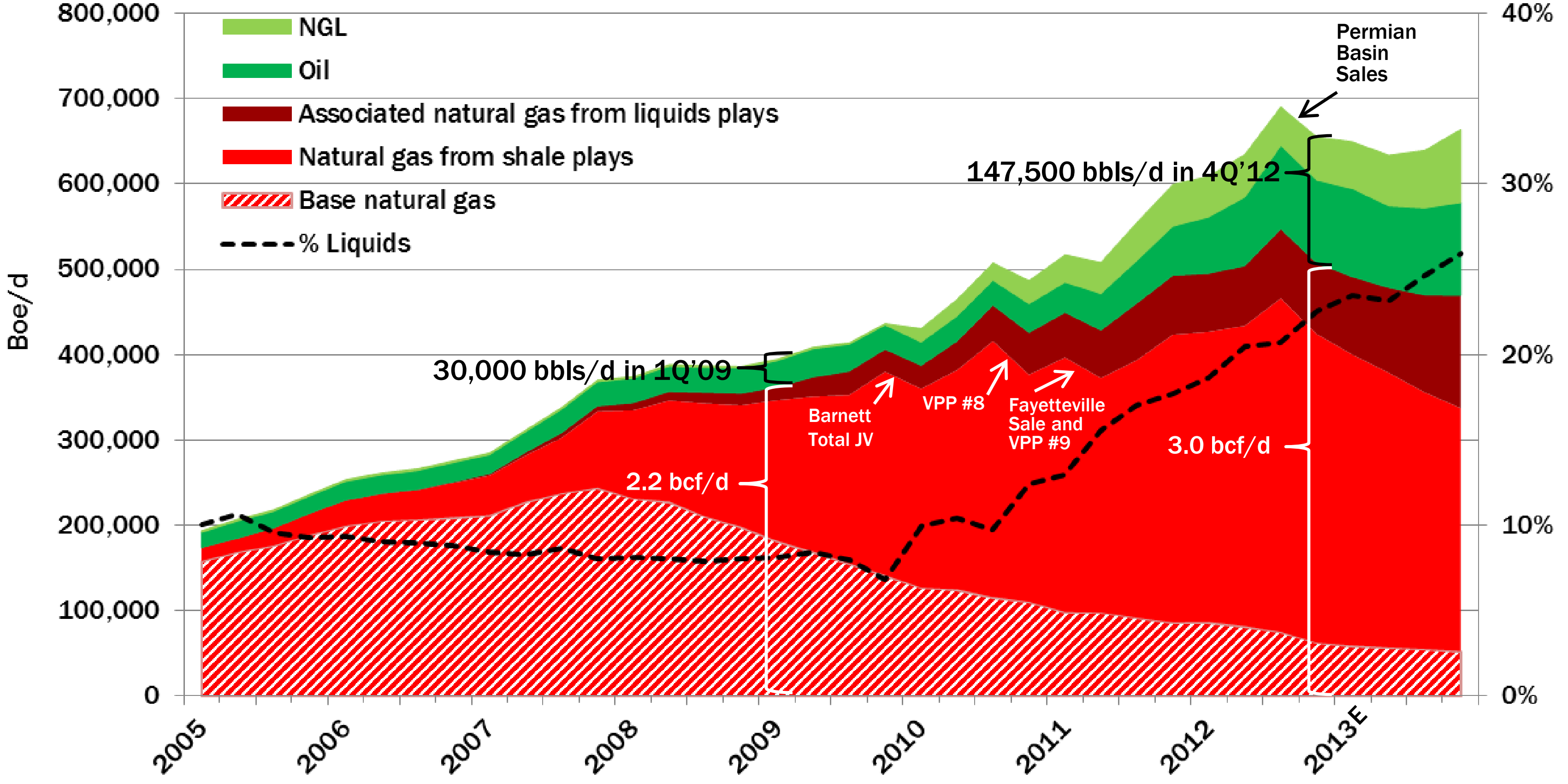
4Q'11 - 4Q'12

CHK has the assets and track record to continue delivering top-tier liquids growth performance

Source: Company reports

CHK'S NEAR-TERM PROJECTED PRODUCTION GROWTH IS 100% LIQUIDS

Chesapeake ENERGY



CHK is projecting net liquids production to average ~170,000 bbls/d in 2013 and to reach ~250,000 bbls/d in 2015

IMPORTANT PLAY DEVELOPMENTS

Eagle Ford Shale:

- Key growth engine for CHK liquids production growth
- 4Q'12 daily net production of 62.5 mboe/d, up 266% YOY, 20% sequentially
- Benefitting from premium differentials to WTI
- Drilling and completion costs down 30% from peak in 2Q'11
- Spud to spud cycle times decreased from 26 to 18 days YOY
- Currently marketing northern Eagle Ford asset package

Utica Shale:

- Production growth expected to accelerate in 2013 as two new third-party natural gas processing plants come online
- Projecting EURs of 5 - 10 bcfe in wet gas window
- Recently drilled the Coe 1H with a peak rate of 2,225 boe/d
- Drilled 184 wells as of YE'12, including 45 producing, 47 WOPL and 92 in various stages of completion

Marcellus Shale:

- 4Q'12 daily net production in northern dry gas portion was 645 mmcfe/d, up 135% YOY, 19% sequentially
- Southern Marcellus wet production to remain flat until ATEX pipeline comes online in late 2013
- Operated rig count reduced to 5 in northern and 3 in southern Marcellus to reduce capex

IMPORTANT PLAY DEVELOPMENTS

Mississippi Lime:

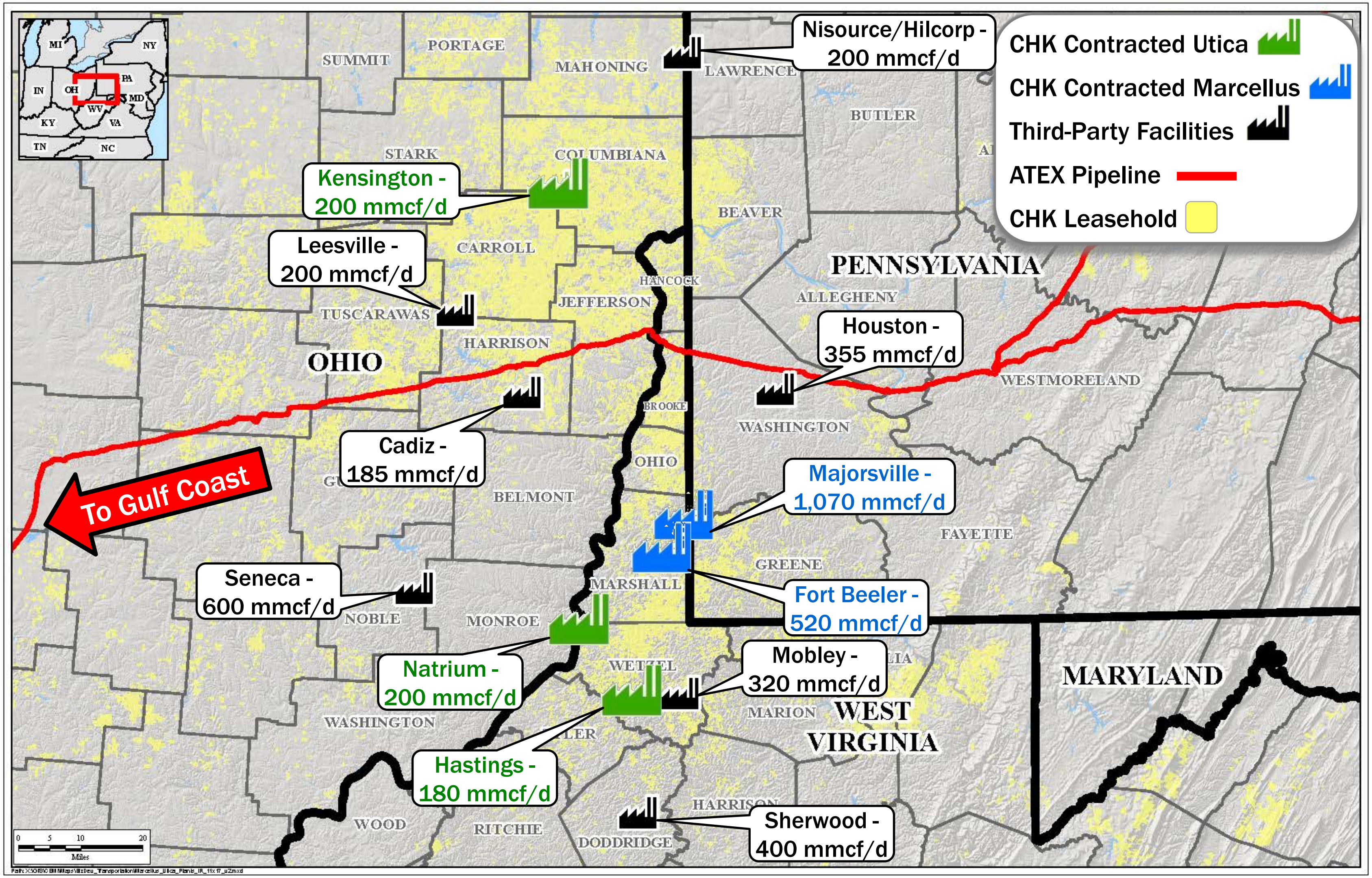
- **Announced JV agreement with Sinopec**
  - Sinopec will purchase a 50% undivided interest in 850,000 net acres (425,000 net to Sinopec), 34 mboe/d of 4Q'12 average production and 140 mmboe of net proved reserves[1]
  - Total consideration of transaction will be $1.02 billion in cash, 93% received upon closing subject to certain title contingencies

Anadarko Basin:

- **Focusing on five plays: the Mississippi Lime, Cleveland, Tonkawa, Granite Wash and Hogshooter**
- **4Q'12 combined production 104.5 mboe/d, up 8% sequentially**
- **Production mix continues to get oilier, with 39% from oil in 4Q'12 vs. 36% in 3Q'12**
- **Currently operating 29 rigs in the five plays**

(1) Production and reserves include Mississippi Lime and other formations

UTICA AND MARCELLUS SOUTH PROCESSING PLANTS[1]

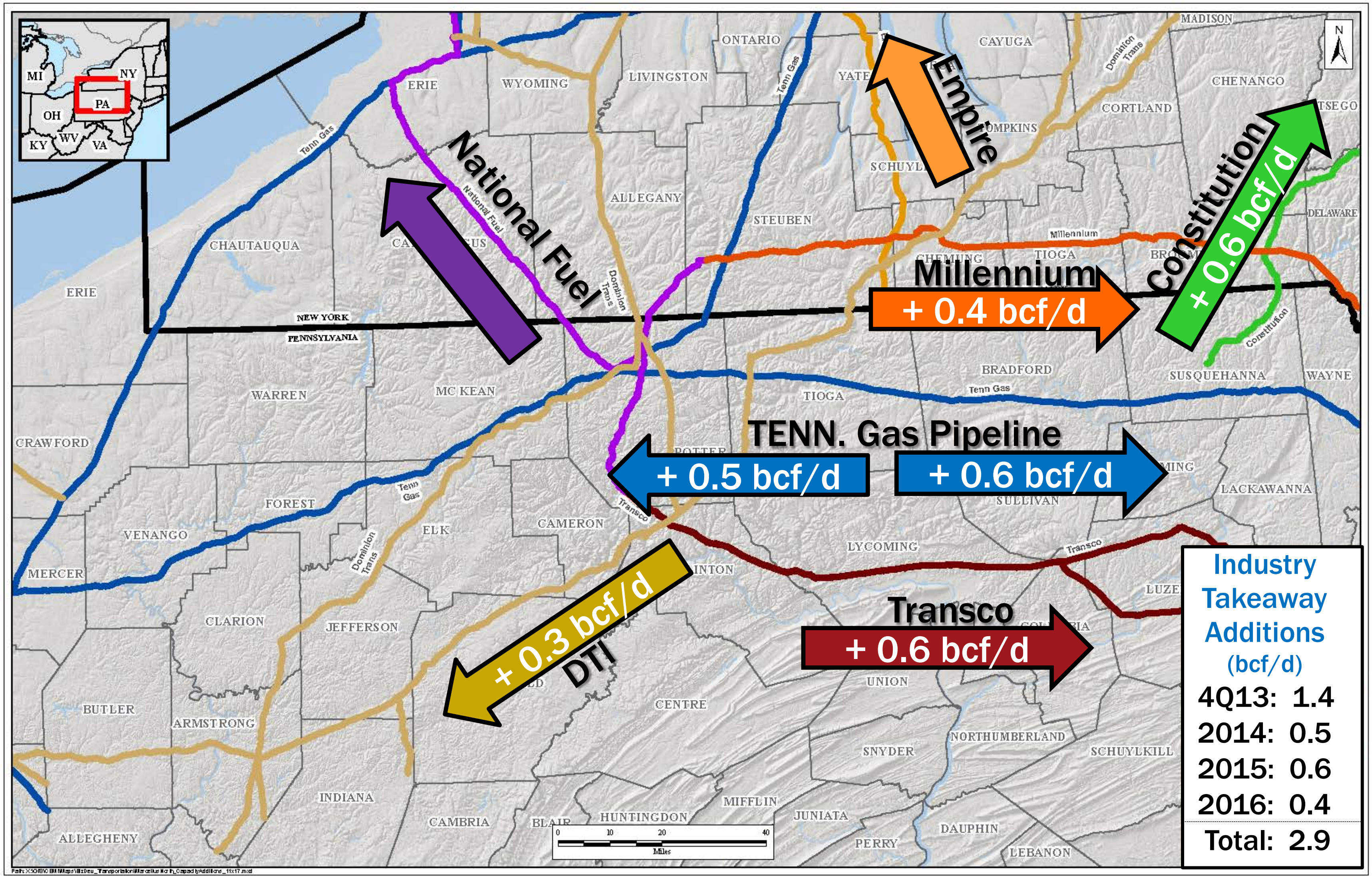


(1) CHK contracted plants reflect plant capacity, not CHK's contract volumes. Note: Natrium's phase one projected to be online in 2Q'13 with future system capacity to reach ~600 mmcf/d. Kensington phase one of ~200 mmcf/d projected to be online in mid-year 2013 with future system capacity to reach 600 mmcf/d.

Source: Company records

MARCELLUS NORTH – ANTICIPATED PIPELINE INDUSTRY TAKEAWAY ADDITIONS

Chesapeake ENERGY

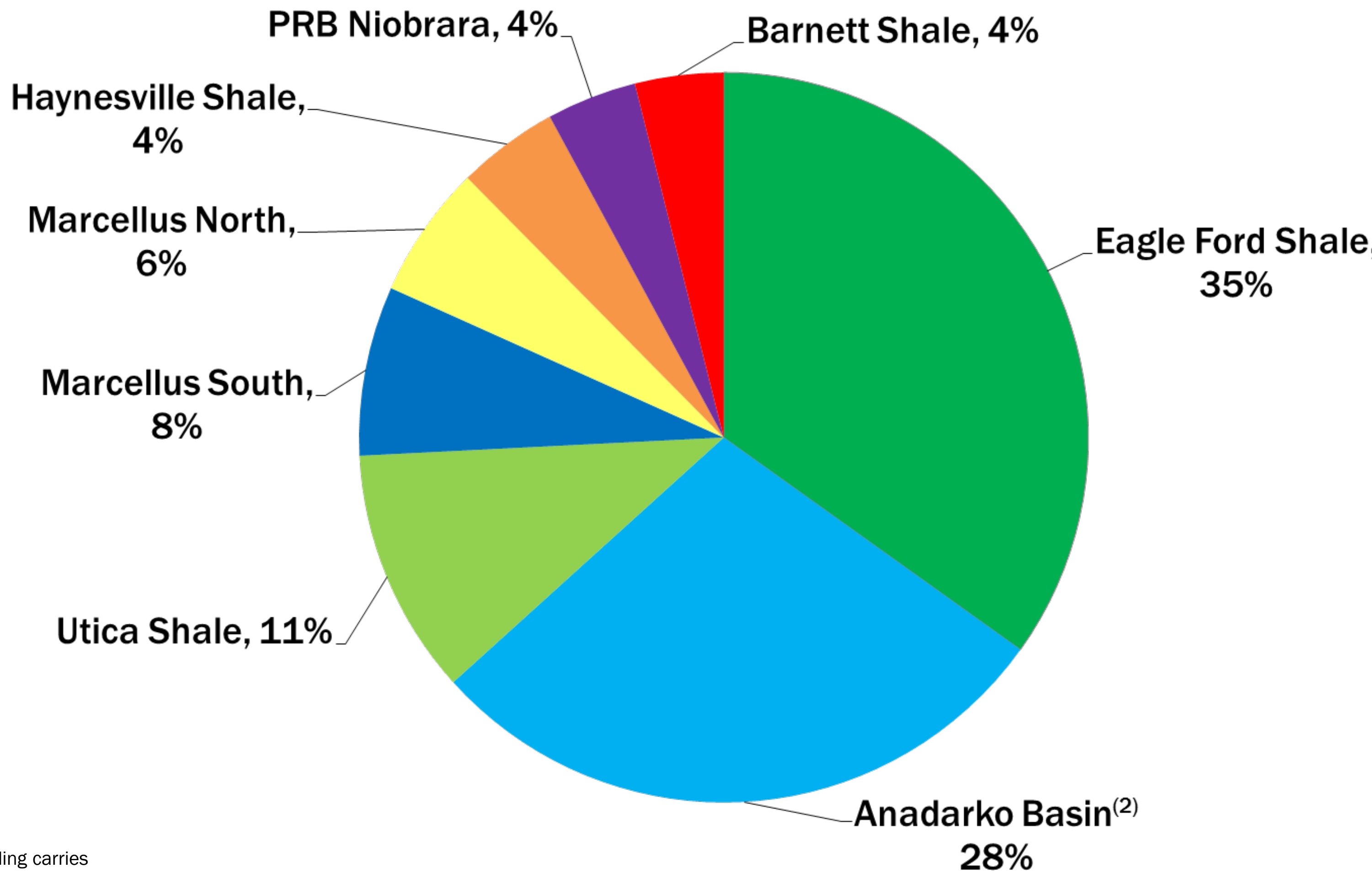


Source: Company reports

Marcellus growth limited by takeaway capacity additions

FINANCIAL SUMMARY

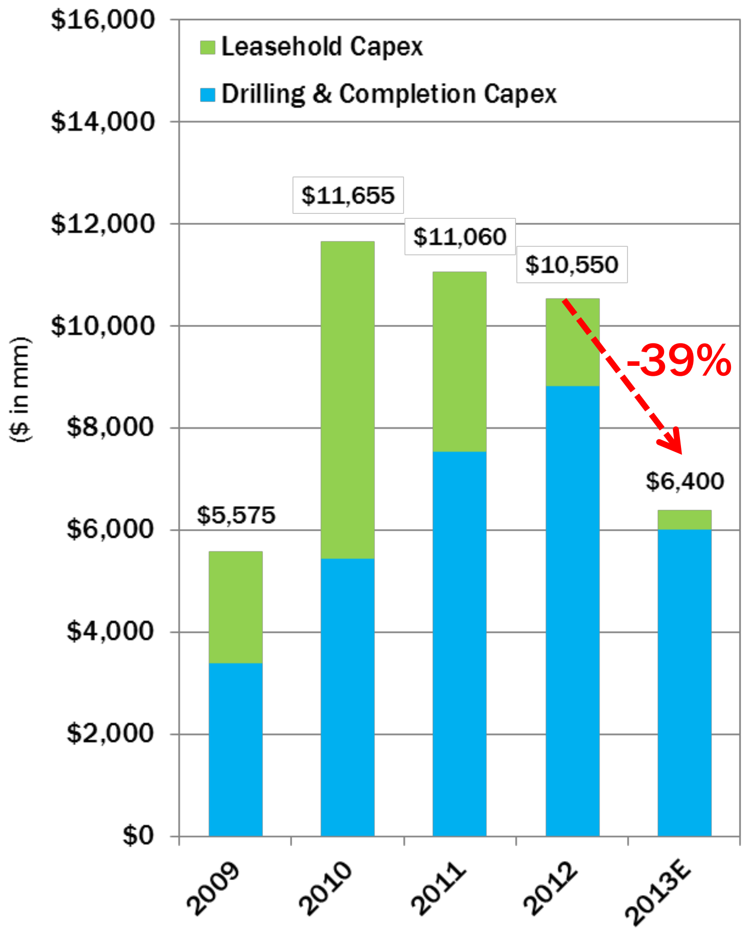
2013 DRILLING AND COMPLETION CAPEX ALLOCATION BY PLAY[1]



(1) Net of drilling carries
(2) Anadarko Basin includes Cleveland, Tonkawa Tight Sand, Mississippi Lime and Granite Washes (Hogshooter)

>85% of 2013 drilling and completion capital expenditures are focused on liquids plays

OPTIMIZATION OF DRILLING AND COMPLETION CAPEX



- **Combined capex on drilling, completion and leasehold projected to decline ~39% from 2012**
- **2013E drilling and completion capex is projected to decline 32% from 2012**
  - At YE'12, CHK's monthly D&C spend was down to a rate consistent with targeted ~$6.0 billion 2013E budget
  - Significant capital efficiency gains anticipated by increasing focus on the "core of the core", reducing rig cycle times and decreasing non-producing well inventories
    - Operated rig count projected to decline ~39% YOY
    - Net wells spud projected to decline ~35% YOY
    - Net wells turned in line to sales to decline only 17%

D&C capex has been optimized to complete transition to liquids, achieve tighter operational focus on the "core of the core" and reach balance between D&C capex and cash flow

OUTLOOK SUMMARY

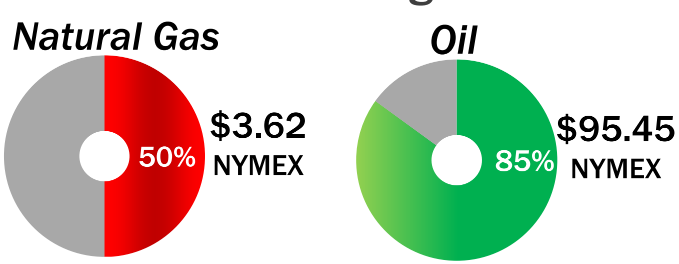
	2011	2012	YE 2013E
Production:			
Natural gas (bcf)	1,004	1,129	1,030 - 1,070
Oil (mbbls)	16,964	31,265	36,000 - 38,000
NGL (mbbls)[1]	14,712	17,615	24,000 - 26,000
Natural gas equivalent (bcfe)	1,194	1,422	1,390 - 1,454
Daily natural gas equivalent midpoint (mmcfe)	3,272	3,886	3,895
YOY production increase	15%	19%	0%
Oil YOY production increase	55%	84%	18%
NGL YOY production increase	97%	20%	42%
Liquids YOY production increase	72%	54%	27%
% Production from liquids	16%	21%	26%
% Realized revenues from liquids[2]	30%	59%	60%
Natural Gas production increase (decrease)	9%	12%	(7%)
Operating costs per mcfe:			
Production expense, production taxes and G&A[3]	$1.44	$1.38	$1.44 - $1.59
Operating cash flow ($mm)[4]	$5,310	$4,070	$4,850 - $5,150
Well costs on proved and unproved properties ($mm)[2]	($7,545)	($8,830)	($5,750 - $6,250)
Acquisition of unproved properties, net ($mm)	($3,515)	($1,720)	($400)

(1) Assumes no ethane rejection
(2) Assumes NYMEX natural gas and oil prices of $3.75/mcf and $95/bbl in 2013
(3) Excluding noncash stock-based compensation
(4) Before changes in assets and liabilities, reconciliation available on page 35; assumes NYMEX prices on open contracts of $3.50 to $4.00/mcf and $95.00/bbl in 2013

2013 FINANCIAL PROJECTIONS(1)

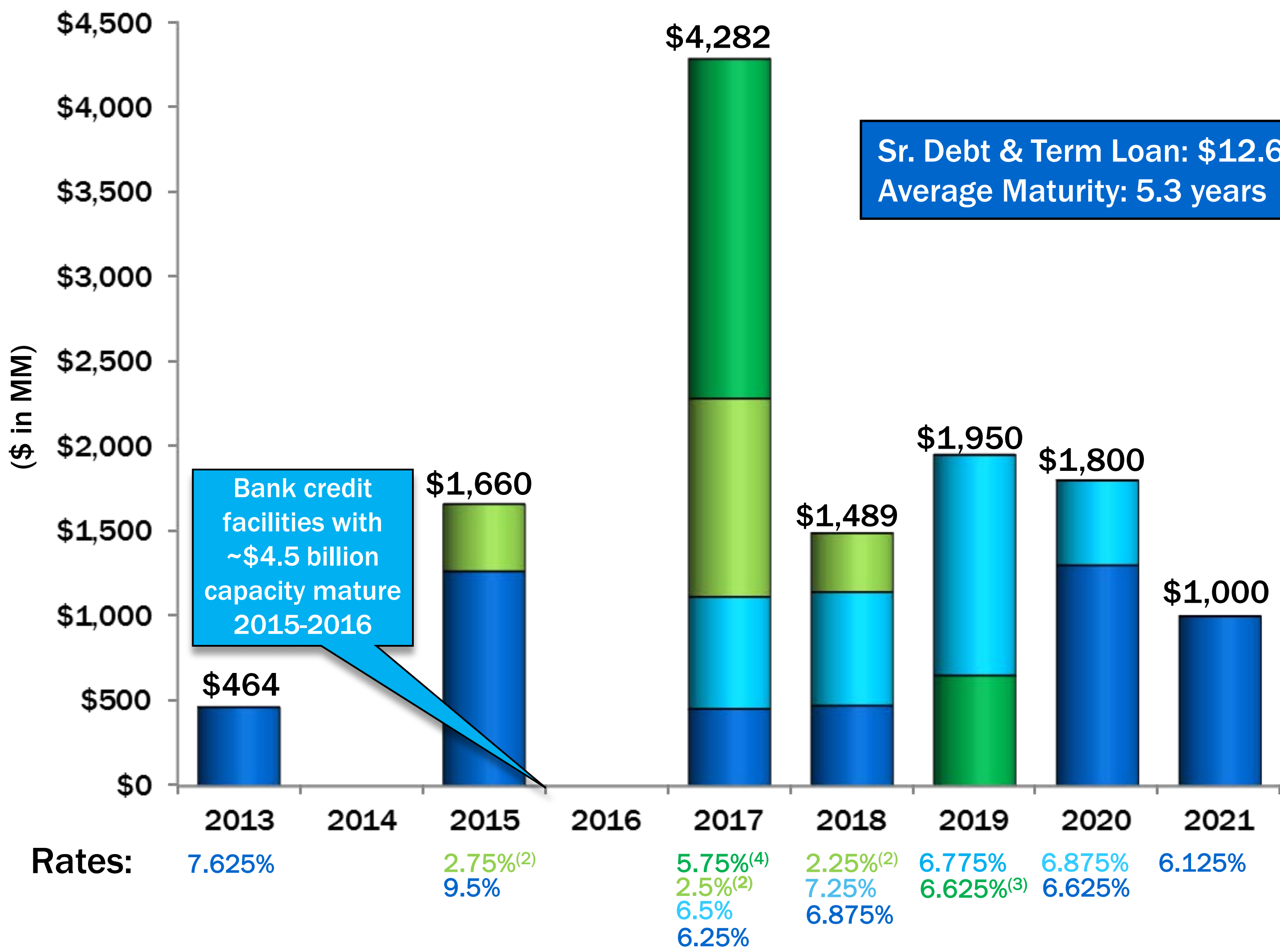
As of 2/21/13 Outlook ($ in mm; oil at $95 NYMEX)	$3.00	$4.00	$5.00
O/G revenue(2)	$6,040	$7,090	$8,140
Ebitda	$4,330	$4,860	$5,360
Operating cash flow(3)	$4,600	$5,130	$5,630
Net income	$740	$1,060	$1,370
Net income per fully diluted share	$0.97	$1.39	$1.80
MEV/operating cash flow(4)	2.9x	2.6x	2.4x
EV/ebitda(5)	7.7x	6.8x	6.2x

2013 Downside Hedge Protection



(1) Reconciliations of financial projections on pages 36-37
(2) Includes effects of estimated realized hedging gains and losses and excludes effects of unrealized hedging gains and losses
(3) Before changes in assets and liabilities
(4) MEV (Market Equity Value) = $ 13.3 billion ($20.00/share x 664 mm fully diluted shares as of 12/31/12)
(5) EV (Enterprise Value) = $33.6 billion (MEV plus $12.8 billion in net debt, $3.1 B in preferred stock and $4.1 billion working capital deficit and other LT liabilities as of 12/31/12)
Note: Hedged positions based on Outlook as of 2/21/2013; 5% of 2013 gas production is hedged under collar arrangements with exposure below $3.03/mcf

DEBT MATURITY SCHEDULE[1]



(1) As of 12/31/12
(2) Recognizes earliest investor put option as maturity for the 2.75% 2035, 2.5% 2037 and 2.25% 2038 Contingent Convertible Senior Notes
(3) COO debt issuance of $650 mm Senior Notes due 2019
(4) Interest at LIBOR plus 4.50%; LIBOR rate is subject to a floor of 1.25% per annum

SUMMARY

VALUE OPPORTUNITY

($ in millions except share price)

Price per share	$15.00	$20.00	$25.00
Common shares @ 12/31/12	664	664	664
Market capitalization	$10,000	$13,300	$16,600
Plus: long-term debt (net of cash)	$12,800	$12,800	$12,800
Plus: preferred shares @ liquidation value	$3,100	$3,100	$3,100
Plus: net working capital and other long-term liabilities	$4,100	$4,100	$4,100
Enterprise value	$30,000	$33,300	$36,600

Enterprise value / 2013E EBITDA(1)	6.4x	7.1x	7.8x
Market capitalization / 2013E operating cash flow(1)	2.0x	2.7x	3.3x
Enterprise value / proved reserves ($/mcfe)(2)(3)	$1.53	$1.70	$1.87
Enterprise value / PV-10 of proved reserves(2)(4)	107%	119%	131%

(1) Ebitda and operating cash flow estimates based on 2/21/2013 Outlook and $3.75/mcf average NYMEX prices and $95/bbl oil in 2013
(2) Excludes value attribution for non-E&P assets
(3) Calculated above using 19.6 tcfe, based on 10-year average NYMEX strip prices. 15.7 tcfe calculated based on SEC pricing
(4) $27.9 billion PV-10 based on 10-year average NYMEX prices and $17.8 billion PV-10 based on SEC pricing

WHY INVEST IN CHK?

- Best assets in the business amassed, now delivering greater shareholder returns from them
- One of the top liquids growth stories in the industry
- Ongoing strategic transformation to a higher-return, lower-risk business model began in 2011 and will be completed by YE'13 – heaviest lifting now behind us
- Targeting "core of the core" in 10 plays, divesting noncore assets
- Committed to financial deleveraging
- Trade at a discount to NAV and equity book value, ongoing transformation should close that gap
- Perhaps the biggest beneficiary of tailwinds from recovering U.S. natural gas market after four years of fighting strong headwinds

CORPORATE INFORMATION

Chesapeake Headquarters

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CHK LISTED NYSE

FORTUNE 100 BEST COMPANIES TO WORK FOR 2013
6TH YEAR IN A ROW!

Other Publicly Traded Securities	CUSIP	Ticker
7.625% Senior Notes due 2013	#165167BY2	CHKJ13
9.5% Senior Notes due 2015	#165167CD7	CHK15K
3.25% Senior Notes due 2016	#165167CJ4	CHK16
6.25% Senior Notes due 2017	#027393390	N/A
6.50% Senior Notes due 2017	#165167BS5	CHK17
6.875% Senior Notes due 2018	#165167CE5	CHK18B
7.25% Senior Notes due 2018	#165167CC9	CHK18A
6.775% Senior Notes due 2019	#165167CH8	CHK19
6.625% Senior Notes due 2020	#165167CF2	CHK20A
6.875% Senior Notes due 2020	#165167BU0	CHK20
6.125% Senior Notes Due 2021	#165167CG0	CHK21
5.375% Senior Notes Due 2021	#165167CK1	CHK21A
5.75% Senior Notes Due 2023	#165167CL9	CHK23
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

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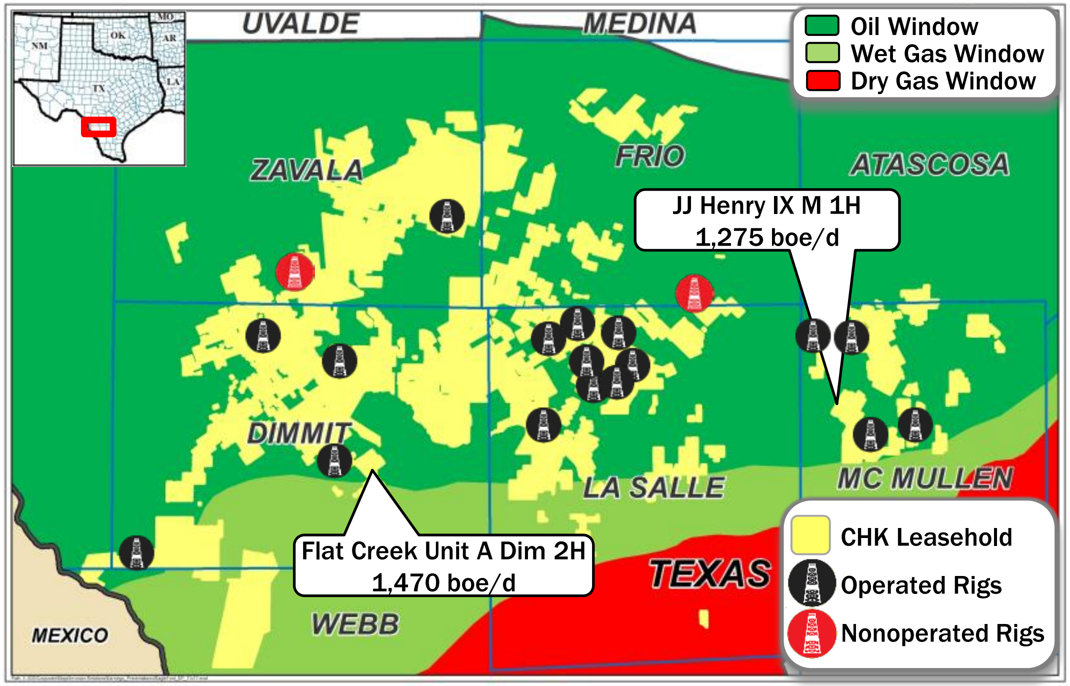
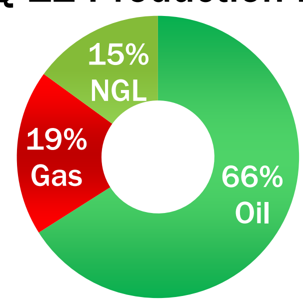
APPENDIX

Chesapeake
ENERGY

EAGLE FORD SHALE OVERVIEW



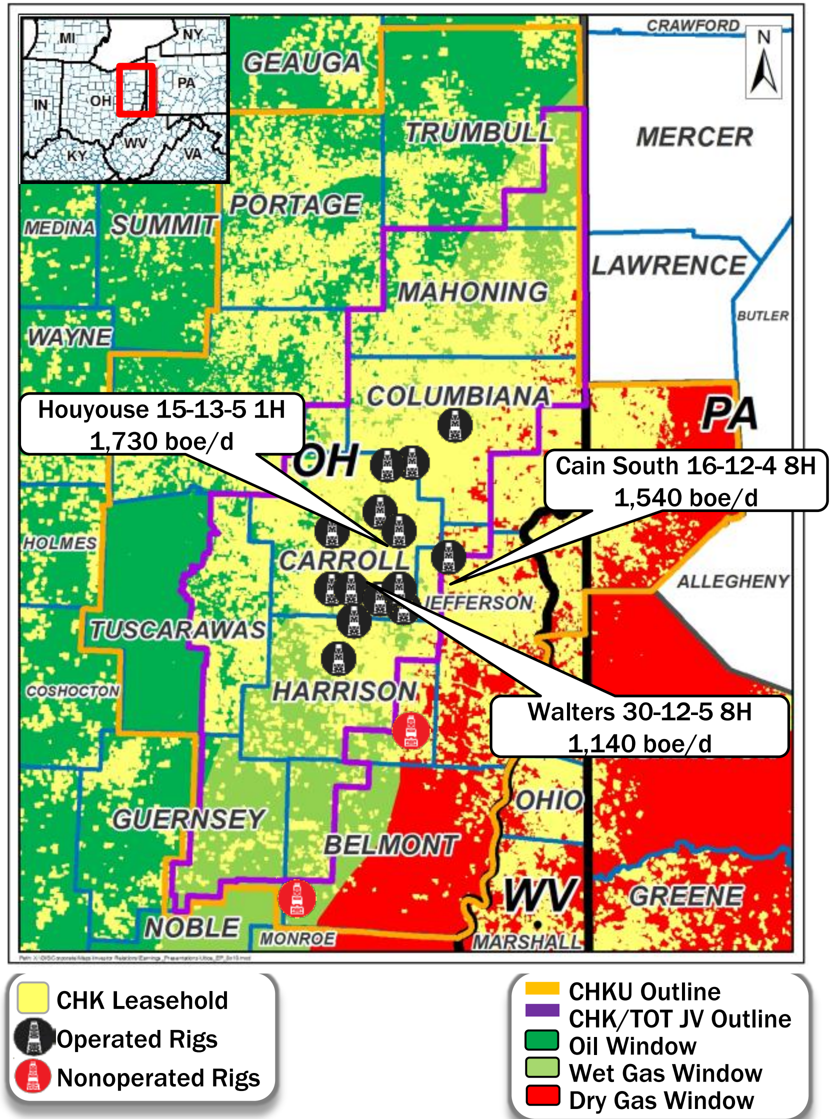
4Q'12 Production Mix



- 485,000 net acres (2nd largest leasehold owner)
- 534 gross operated producing wells
  - Brought online 98 wells in 4Q '12
    - 92% of wells with IP >500 boe/d, 28% at more than 1,000 boe/d
- 4Q'12 net production averaged 62.5 mboe/d
  - 143.2 gross operated mboe/d in 4Q'12, up from zero in 4Q'09
- On pace to HBP core and Tier 1 Eagle Ford acreage by YE'13
- Currently operating 17 rigs
- Marketing existing leasehold and producing assets outside core development area

Note: 24-hour peak rates shown on map assume 100% ethane recovery

UTICA SHALE OVERVIEW

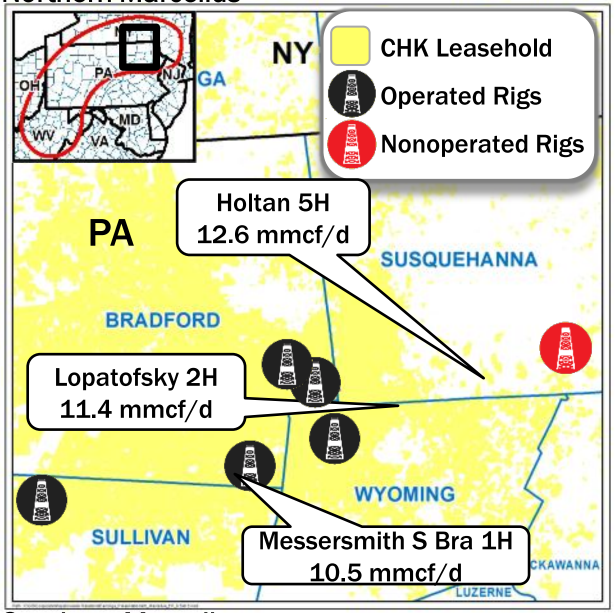


- ~1.0 mm net acres (largest leasehold owner)
- Discovered play in 2010
- Drilled a total of 184 wells in the Utica play
  - 45 producing wells, 47 wells drilled, but WOPL, and 92 wells in various stages of completion
- Expect larger production growth in 2013 as midstream constraints are reduced and two new third-party gas processing complexes are operational
- Currently operating 14 rigs
- Remaining drilling carry from Total was ~$1.15 billion at YE'12; anticipate using 100% of the drilling carry by YE'14

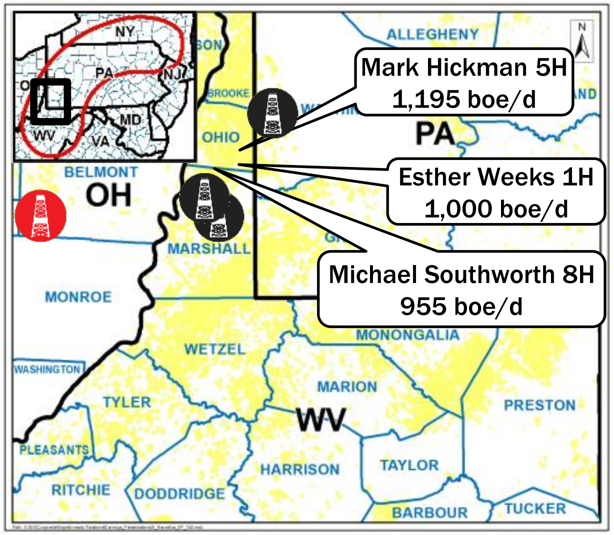
Note: 24-hour peak rates shown on map assume 100% ethane recovery

MARCELLUS SHALE OVERVIEW

Northern Marcellus



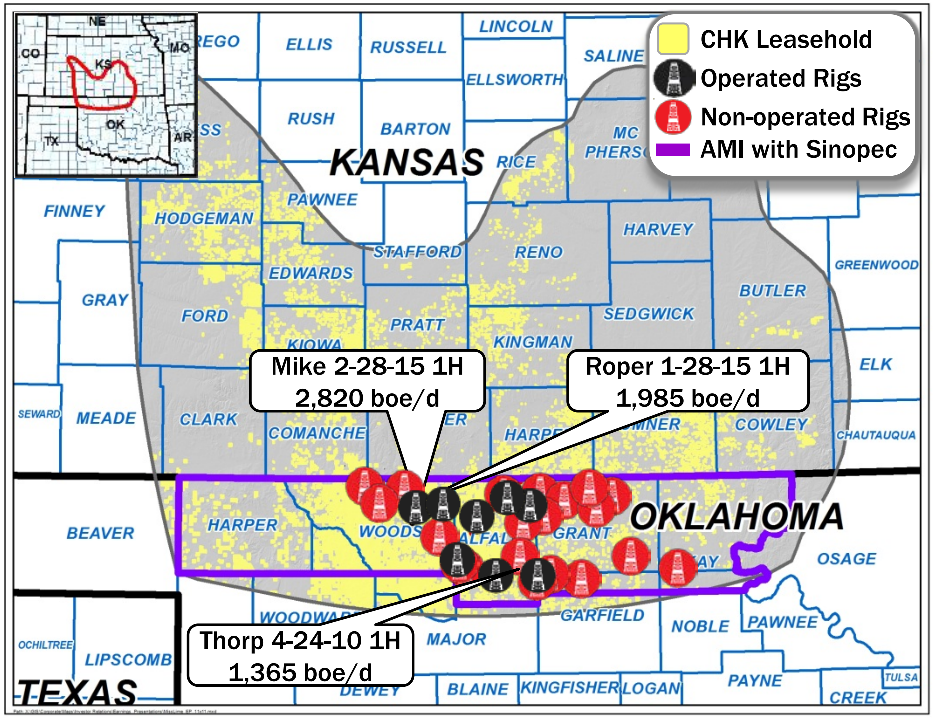
Southern Marcellus



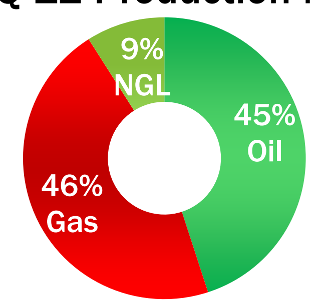
Note: 24-hour peak rates shown on map assume 100% ethane recovery

- **Largest leasehold owner in the play with ~1.8 mm net acres**
  - ~1.5 mm net acres in northern dry gas portion
  - ~285,000 net acres in southern wet gas portion of the play
- **4Q'12 production**
  - Northern dry gas portion of play averaged 645 mmcfe/d, up 135% YOY and 19% sequentially
  - Southern wet gas portion of play averaged ~155 mmcfe/d
    - Production to remain flat until ATEX pipeline is online in late 2013
- **Currently operating 5 rigs in the northern dry gas window and 3 rigs in southern wet gas portion**

MISSISSIPPI LIME OVERVIEW



4Q'12 Production Mix



- ~2 mm net acres (largest leasehold owner)
- Discovered horizontal play in 2007
- 273 horizontal producing wells
  - Brought online 55 wells in 4Q '12, 46 wells drilled, but not yet online
- 4Q'12 net production averaged 32.5 mboe/d
  - 41.6 gross operated mboe/d, up 208% YOY and 30% sequentially
- Currently operating 8 rigs
- Announced JV agreement with Sinopec
  - Sinopec agreed to purchase a 50% undivided interest in 850,000 net acres
  - Total consideration of transaction will be $1.02 billion in cash, 93% received upon closing

Note: 24 hour peak rates shown on map assume 100% ethane recovery

TOP 20 U.S. LIQUIDS PRODUCERS

	Daily U.S. Liquids Production[(1)(2)] Company	Ticker	4Q'12	3Q'12	4Q'11	4Q'12 vs. 3Q'12 % Change	4Q'12 vs. 4Q'11 % Change	2011 Reported Proved U.S. Liquids Reserves (MMBBL)	RP Ratio[(3)]	2011 Reported Proved U.S. Liquids Reserves Ranking	U.S. Liquids Rigs Drilling on 2/22/13[(4)]	U.S. Liquids Rigs Drilling on 1/1/12[(4)]	U.S. Liquids Rigs Drilling % Change Since 1/1/12
1	Chevron	CVX	462	440	447	5.0%	3.4%	1,311	8	5	13	6	117%
2	ConocoPhillips	COP	436	378	413	15.3%	5.6%	2,009	13	3	18	14	29%
3	ExxonMobil	XOM	430	397	432	8.3%	(0.5%)	2,372	15	2	15	21	(29%)
4	BP	BP	402	356	439	12.9%	(8.4%)	2,858	19	1	2	1	100%
5	Occidental	OXY	342	334	310	2.4%	10.3%	1,751	14	4	33	33	0%
6	Shell	RDS	249	201	218	23.9%	14.2%	838	9	7	6	7	(14%)
7	Anadarko	APC	246	231	204	6.5%	20.6%	1,034	12	6	18	18	0%
8	EOG	EOG	211	219	174	(3.8%)	21.0%	722	9	9	51	47	9%
9	Apache	APA	193	172	152	11.9%	27.0%	794	11	8	59	25	136%
10	Devon	DVN	166	159	144	4.8%	15.3%	693	11	10	41	17	141%
11	Chesapeake	CHK	148	143	106	3.4%	38.9%	546	10	12	77	89	(13%)
12	BHP	BHP	138	113	108	22.2%	28.3%	267	5	18	30	7	329%
13	Hess	HES	136	125	102	8.8%	33.3%	293	6	16	16	13	23%
14	Marathon	MRO	133	111	83	19.8%	60.2%	279	6	17	22	23	(4%)
15	Pioneer	PXD	99	93	76	5.9%	29.6%	641	18	11	31	35	(11%)
16	Plains	PXP	93	64	52	46.4%	78.0%	244	7	19	11	8	38%
17	Continental	CLR	76	72	54	5.8%	41.8%	326	12	14	29	29	0%
18	Noble	NBL	75	68	55	10.3%	36.4%	244	9	20	7	3	133%
19	Whiting	WLL	74	71	59	4.2%	25.3%	298	11	15	26	23	13%
20	Denbury	DNR	65	68	63	(3.4%)	3.2%	358	15	13	3	9	(67%)
	Totals		4,175	3,815	3,692	9.4%	13.1%	17,877			508	428	19%
	Other Producers										742	596	24%
	Total										1,250	1,024	22%

(1) Based on 4Q'12 company reports
(2) In mbbls/day
(3) Based on annualized production
(4) Source: Smith Bits, a Schlumberger Company, onshore rig count

TOP 20 U.S. NATURAL GAS PRODUCERS

	Company	Ticker	Daily U.S. Natural Gas Production[1][2] 4Q'12	3Q'12	4Q'11	4Q'12 vs. 3Q'12 % Change	4Q'12 vs. 4Q'11 % Change	2011 Reported U.S. Net Proved Natural Gas Reserves (BCFE)	RP Ratio[3]	2011 Reported Proved U.S. Natural Gas Reserves Ranking	U.S. Gas Rigs Drilling on 2/22/13[4]	U.S. Gas Rigs Drilling on 1/1/12[4]	U.S. Gas Rigs % Drilling Change Since 1/1/12
1	ExxonMobil	XOM	3,747	3,712	4,005	0.9%	(6.4%)	26,366	19	1	29	48	(40%)
2	Chesapeake	CHK	3,043	3,282	2,957	(7.3%)	2.9%	15,515	14	2	9	73	(88%)
3	Anadarko	APC	2,521	2,499	2,328	0.9%	8.3%	8,365	9	7	15	32	(53%)
4	Devon	DVN	2,029	2,067	2,085	(1.8%)	(2.7%)	9,513	13	5	25	35	(29%)
5	Southwestern	SWN	1,628	1,567	1,448	3.9%	12.4%	5,893	10	9	20	14	43%
6	BP	BP	1,593	1,545	1,817	3.1%	(12.3%)	13,552	23	3	3	12	(75%)
7	ConocoPhillips	COP	1,564	1,558	1,606	0.4%	(2.6%)	10,148	18	4	6	15	(60%)
8	EnCana	ECA	1,540	1,606	1,944	(4.1%)	(20.8%)	8,432	15	6	13	24	(46%)
9	BHP	BHP	1,364	1,366	1,346	(0.1%)	1.3%	2,730	5	20	8	25	(68%)
10	Chevron	CVX	1,273	1,184	1,290	7.5%	(1.3%)	3,646	8	14	6	6	0%
11	Shell	RDS	1,209	1,010	1,032	19.7%	17.2%	3,196	7	16	8	20	(60%)
12	WPX	WPX	1,051	1,078	1,070	(2.5%)	(1.8%)	3,983	10	13	3	14	(79%)
13	EOG	EOG	981	1,022	1,085	(4.0%)	(9.6%)	6,046	17	8	5	14	(64%)
14	Apache	APA	891	863	863	3.1%	3.2%	2,976	9	17	4	5	(20%)
15	Cabot	COG	813	682	561	19.3%	45.0%	2,910	10	18	5	5	0%
16	Occidental	OXY	800	812	833	(1.5%)	(4.0%)	3,365	12	15	4	6	(33%)
17	Equitable	EQT	784	703	538	11.6%	45.6%	5,347	19	10	8	12	(33%)
18	QEP	QEP	666	701	702	(5.0%)	(5.1%)	2,749	11	19	9	11	(18%)
19	Range Resources	RRC	655	623	491	5.1%	33.5%	4,010	17	12	8	15	(47%)
20	Ultra	UPL	635	665	702	(4.6%)	(9.6%)	4,779	21	11	2	6	(67%)
	Totals		28,787	28,546	28,703	0.8%	0.3%	143,521			190	392	(52%)
	Other Producers										147	374	(61%)
	Total										337	766	(56%)

(1) Based on 4Q'12 company reports
(2) In mmcf/day
(3) Based on annualized production
(4) Source: Smith Bits, a Schlumberger Company, onshore rig count

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)(unaudited)

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$ 864	$ 949	$ 2,179
Changes in assets and liabilities	282	169	(868)
OPERATING CASH FLOW[(a)]	$ 1,146	$ 1,118	$ 1,311

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
NET INCOME (LOSS)	$ 344	$ (1,971)	$ 487
Income tax expense (benefit)	219	(1,260)	312
Interest expense	14	36	7
Depreciation and amortization of other assets	71	66	85
Natural gas, oil and NGL depreciation, depletion and amortization	651	762	484
EBITDA[(b)]	$ 1,299	$ (2,367)	$ 1,375

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$ 864	$ 949	$ 2,179
Changes in assets and liabilities	282	169	(868)
Interest expense	14	36	7
Unrealized gains (losses) on natural gas, oil and NGL derivatives	125	(104)	(345)
Impairment of natural gas and oil properties	—	(3,315)	—
Net gains (losses) on sales of fixed assets	272	(7)	439
Impairments of fixed assets and other	(59)	(14)	(42)
Gains (losses) on investments	(2)	4	22
Stock-based compensation	(27)	(30)	(34)
Losses on purchases of debt	(200)	—	—
Other items	30	(55)	17
EBITDA[(b)]	$ 1,299	$ (2,367)	$ 1,375

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

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

RECONCILIATION OF ADJUSTED EBITDA

($ in millions)(unaudited)

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
EBITDA	$ 1,299	$ (2,367)	$ 1,375
Adjustments:			
Unrealized (gains) losses on natural gas, oil and NGL derivatives	(125)	104	345
Impairment of natural gas and oil properties	—	3,315	—
Net (gains) losses on sales of fixed assets	(272)	7	(439)
Impairments of fixed assets and other	59	38	42
Net income attributable to noncontrolling interests	(44)	(41)	(15)
Gains on sales of investments	(31)	(31)	—
Losses on purchases of debt	200	—	—
Other	3	(4)	—
Adjusted EBITDA[a]	$ 1,089	$ 1,021	$ 1,308

(a) Adjusted ebitda excludes certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to ebitda because:

i. Management uses adjusted ebitda to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.

ii. Adjusted ebitda is more comparable to estimates provided by securities analysts.

iii. Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS

($ in millions, except per-share data)(unaudited)

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
Net income (loss) available to common stockholders	$ 257	$ (2,055)	$ 429
Adjustments, net of tax:			
Unrealized (gains) losses on derivatives	(78)	63	207
Impairment of natural gas and oil properties	—	2,022	—
Net (gains) losses on sales of fixed assets	(166)	4	(268)
Impairments of fixed assets and other	36	23	26
Gains on sales of investments	(19)	(19)	—
Losses on purchases or exchanges of debt	122	—	—
Other	1	(3)	—
Adjusted net income available to common stockholders[a]	153	35	394
Preferred stock dividends	43	43	43
Total adjusted net income	$ 196	$ 76	$ 437
Weighted average fully diluted shares outstanding[b]	754	754	750
Adjusted earnings per share assuming dilution[a]	$ 0.26	$ 0.10	$ 0.58

(a) Adjusted net income available to common stockholders and adjusted earnings per share assuming dilution exclude certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to GAAP earnings because:

i. Management uses adjusted net income available to common stockholders to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
ii. Adjusted net income available to common stockholders is more comparable to earnings estimates provided by securities analysts.
iii. Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

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

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)(unaudited)

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,841	$ 5,903
Changes in assets and liabilities	1,228	(594)
OPERATING CASH FLOW[a]	$ 4,069	$ 5,309

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
NET INCOME (LOSS)	$ (594)	$ 1,757
Income tax expense (benefit)	(380)	1,123
Interest expense	77	44
Depreciation and amortization of other assets	304	291
Natural gas, oil and NGL depreciation, depletion and amortization	2,507	1,632
EBITDA[b]	$ 1,914	$ 4,847

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,841	$ 5,903
Changes in assets and liabilities	1,228	(594)
Interest expense	77	44
Unrealized gains (losses) on natural gas, oil and NGL derivatives	561	(789)
Impairment of natural gas and oil properties	(3,315)	—
Net gains on sales of fixed assets	267	437
Impairments of fixed assets and other	(316)	(46)
Gains (losses) on investments	(180)	41
Stock-based compensation	(120)	(153)
Gains on sales of investments	1,092	—
Losses on purchases of debt	(200)	(5)
Other items	(21)	9
EBITDA[b]	$ 1,914	$ 4,847

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

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

RECONCILIATION OF FINANCIAL PROJECTIONS: EBITDA TO OPERATING CASH FLOW

As of 2/21/13 Outlook	2013		
($ in mm; oil at ~$95 NYMEX)	$3.00	$4.00	$5.00
O/G revenue (unhedged)[1]	$6,040	$7,090	$8,140
Hedging effect[2]	330	(150)	(660)
Marketing and other	300	300	300
Production taxes 4%	(230)	(270)	(310)
Production cost (LOE)	(1,320)	(1,320)	(1,320)
G&A[3]	(590)	(590)	(590)
Net income attributable to noncontrolling interest	(200)	(200)	(200)
Ebitda	$ 4,330	$ 4,860	$ 5,360
Interest expense incl. capitalized interest	(110)	(110)	(110)
Non-cash interest expense	60	60	60
Stock-based compensation	120	120	120
Net income attributable to noncontrolling interest	200	200	200
Operating cash flow[4]	$ 4,600	$ 5,130	$ 5,630
MEV/operating cash flow[5]	2.9x	2.6x	2.4x
EV/ebitda[6]	7.7x	6.8x	6.2x
Net debt/ebitda	3.0x	2.6x	2.4x

(1) Before effects of hedges gains or losses
(2) Includes effects of estimated realized hedging gains and losses and excludes effects of unrealized hedging gains and losses
(3) Includes expense related to noncash stock-based compensation
(4) Before changes in assets and liabilities
(5) MEV (Market Equity Value) = $13.3 billion ($20.00/share x 664 mm fully diluted shares as of 12/31/12)
(6) EV (Enterprise Value) = $33.6 billion (MEV plus $12.8 billion in net debt, $3.1 B in preferred stock and $4.1 billion working capital deficit and other LT liabilities as of 12/31/12)

RECONCILIATION OF FINANCIAL PROJECTIONS: OPERATING CASH FLOW TO NET INCOME

As of 2/21/13 Outlook	2013		
($ in mm; oil at ~$95 NYMEX)	$3.00	$4.00	$5.00
Operating cash flow[1]	$4,600	$5,130	$5,630
Oil and gas depreciation	(2,490)	(2,490)	(2,490)
Depreciation of other assets	(390)	(390)	(390)
Income taxes (39% rate)	(600)	(810)	(1,000)
Non-cash interest expense	(60)	(60)	(60)
Stock-Based Compensation	(120)	(120)	(120)
Net income attributable to noncontrolling interest	(200)	(200)	(200)
Net income attributable to Chesapeake	$740	$1,060	$1,370
Earnings per common share (fully diluted)	$0.97	$1.39	$1.80

(1) Before changes in assets and liabilities