

All Oil Companies Are Not Alike.

A Different Kind of Oil Company



Leading CO₂ Enhanced Oil Recovery (EOR) Company in the U.S. with a Unique Profile

Scale

- ~\$8.9 billion enterprise value
- 72,337 BOE/d production (2Q12)⁽¹⁾
- Highest operating margins and capital efficiency in peer group⁽²⁾

Performance

- 30% compound annual growth rate (CAGR) in EOR production over the last 12 years
- 2nd Largest CO₂ EOR Producer in North America

Platform

- Infrastructure in place with secure CO₂ supply
- More than 1 billion barrels of potential oil reserves
- Experienced management team

Liquidity

- ~\$1.1 billion of credit facility availability at 6/30/12
- Capital budget seeks to balance expenditures with free cash flow

Sustainable Growth

- Sustainable EOR growth profile at 13-15% CAGR through 2020

(1) Production figure still includes recently sold Bakken assets, see slide 8 for transaction details

(2) Please reference slides 11 and 12 for more information

Denbury at a Glance



		Pro forma for sale ⁽¹⁾
Total 3P Reserves (12/31/11)	~1.3 BBOE	~1.1 BBOE
% Oil Production (2Q12)	93%	~93% ⁽²⁾
Total Net Debt (6/30/12)	\$2.9 billion	~\$1.8 billion
Total Daily Production – BOE/d (2Q12)	72,337	~60,300 ⁽²⁾
Proved PV-10 (12/31/11) \$96.19 NYMEX Oil Price	\$10.6 billion	~\$10.6 billion ⁽³⁾
Market Cap (8/31/12)	~\$6.0 billion	
CO ₂ 3P Reserves (12/31/11)	~16 Tcf	
CO ₂ Pipelines Controlled & Under Construction	~1,000 miles	
Credit Facility Availability (6/30/12)	~\$1.1 billion	

(1) Pro forma for recently announced Bakken sale, **includes** Hartzog Draw and Webster.

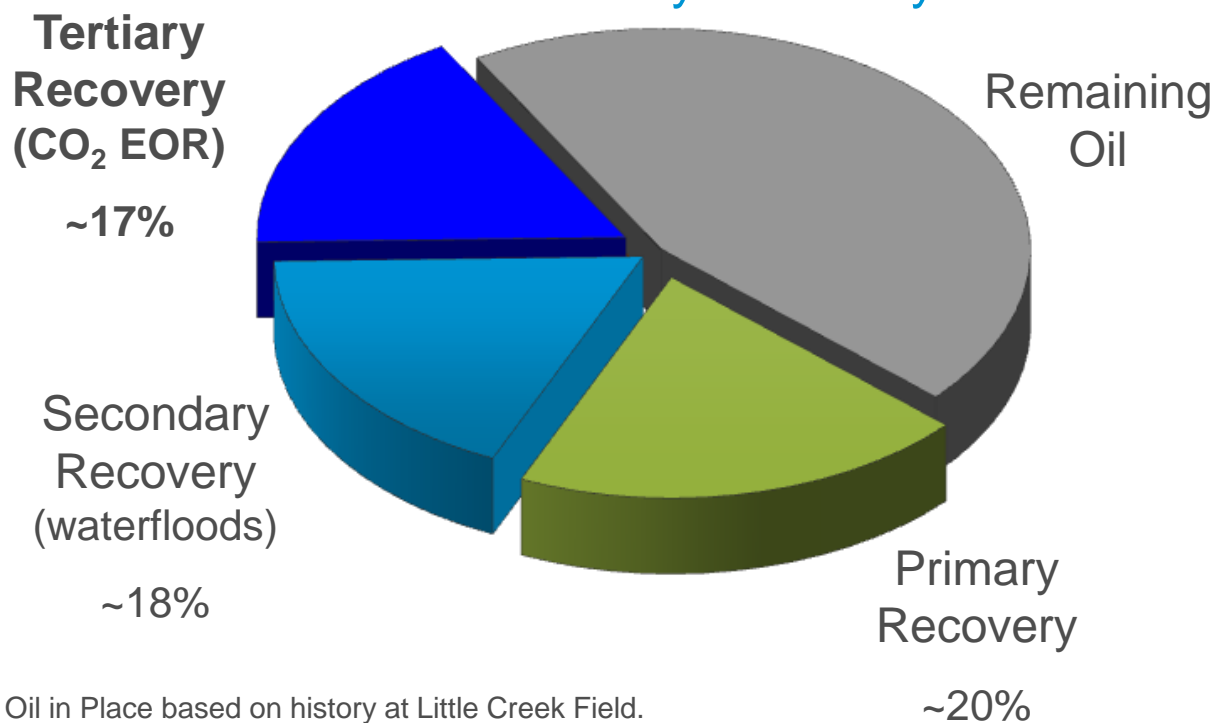
(2) Pro forma production adjusts for production sold and includes roughly 3,600 BOE/d from recently announced acquisition of Hartzog Draw and Webster.

(3) PV-10 value at 12/31/11 pro forma for recently announced Bakken sale, excluding Bakken at 12/31/11 and including previously disclosed PV-10 for Oyster Bayou and Hastings at 6/30/2012 using a \$95.67 NYMEX Oil Price for Oyster Bayou and Hastings. Does not include Thompson, Hartzog Draw or Webster, nor does it exclude net cash flows from the first six months of 2012.

What is CO₂ EOR & How Much Does It Recover?

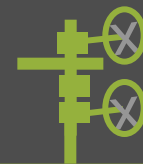


EOR Delivers Almost as Much Production as Primary or Secondary Recovery⁽¹⁾



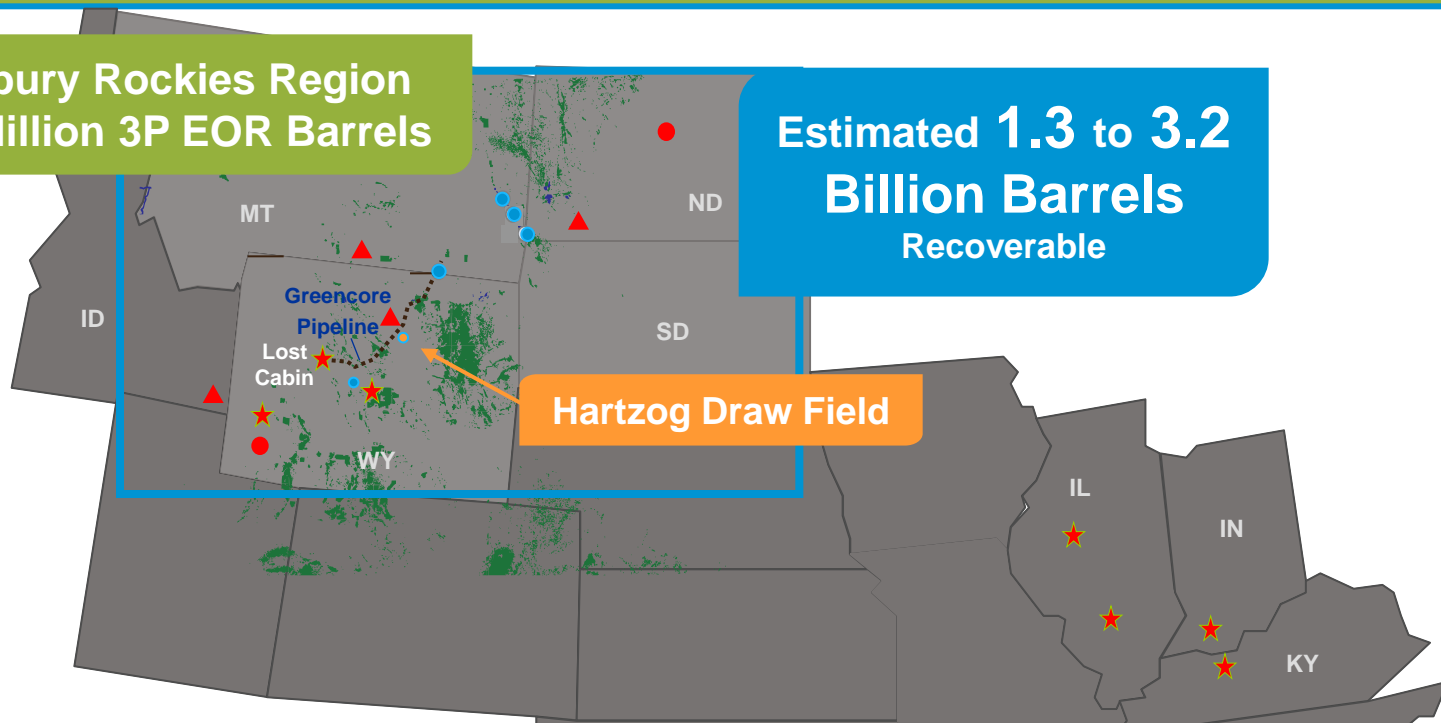
(1) Recovery of Original Oil in Place based on history at Little Creek Field.

Our Two EOR Target Areas: Up to 10 Billion Barrels Recoverable with EOR



Denbury Rockies Region
258 Million 3P EOR Barrels

**Estimated 1.3 to 3.2
Billion Barrels
Recoverable**

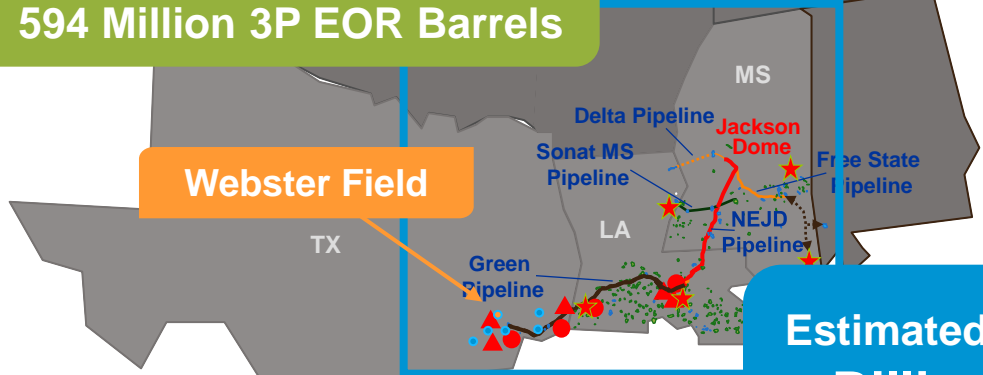


Hartzog Draw Field

- Existing CO₂ Pipelines
- CO₂ Pipelines Under Development
- Denbury owned Fields With EOR Potential
- Existing Anthropogenic CO₂ Sources
- ▲ Proposed Coal to Gas or Liquids
- ★ Existing or Proposed CO₂ Source Owned or Contracted

Denbury Gulf Coast Region
594 Million 3P EOR Barrels

**Estimated 3.4 to 7.5
Billion Barrels
Recoverable**



Webster Field

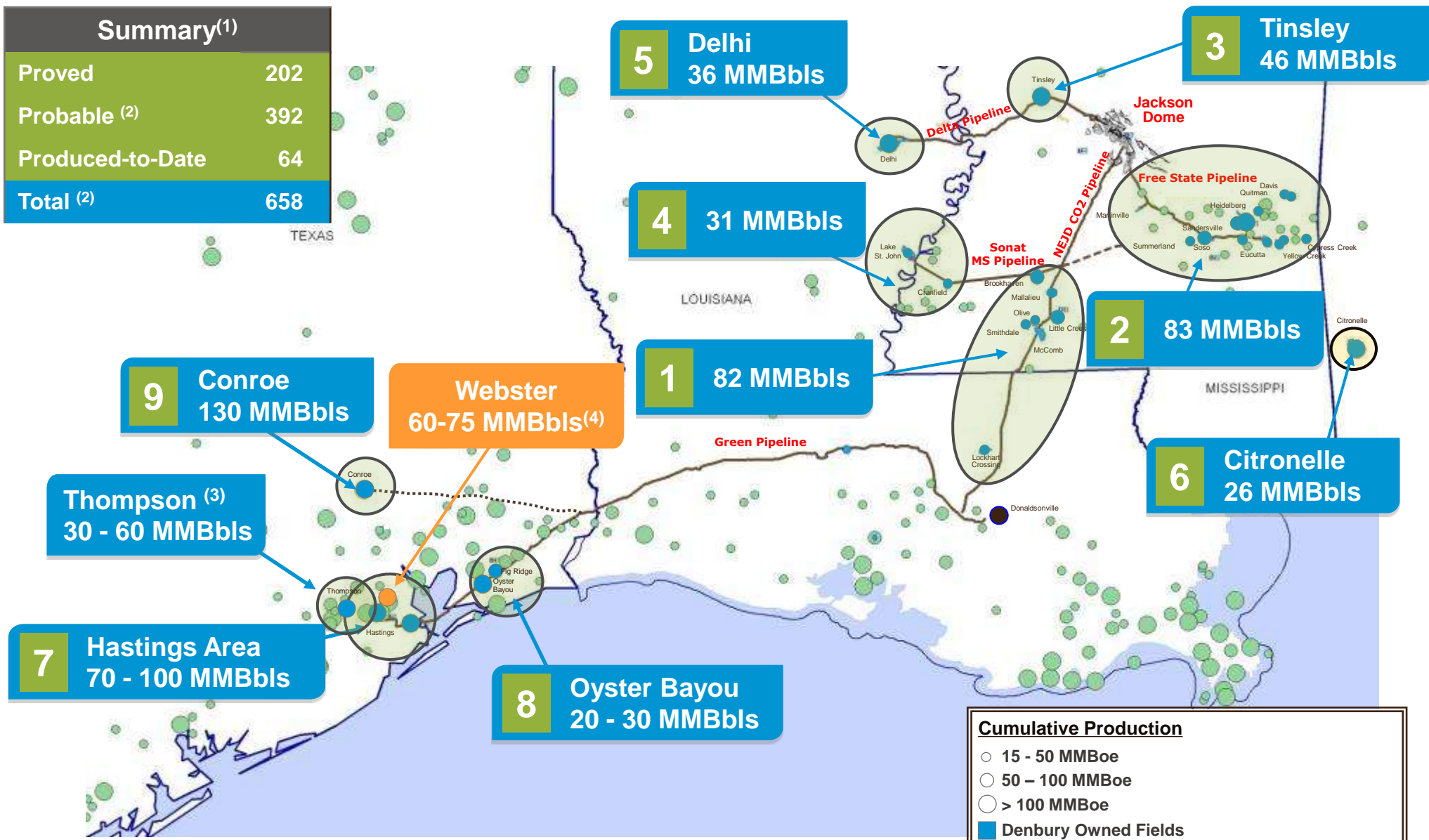
Source: DOE 2005 and 2006 reports.

Note: 3P total reserves as of 12/31/11, based on a variety of recovery factors, includes recently announced acquisition of Hartzog Draw and Webster field. See slide 8 for transaction details.

Gulf Coast Region: Control of CO₂ Sources & Pipeline Infrastructure Provides a Strategic Advantage



Summary ⁽¹⁾	
Proved	202
Probable ⁽²⁾	392
Produced-to-Date	64
Total ⁽²⁾	658



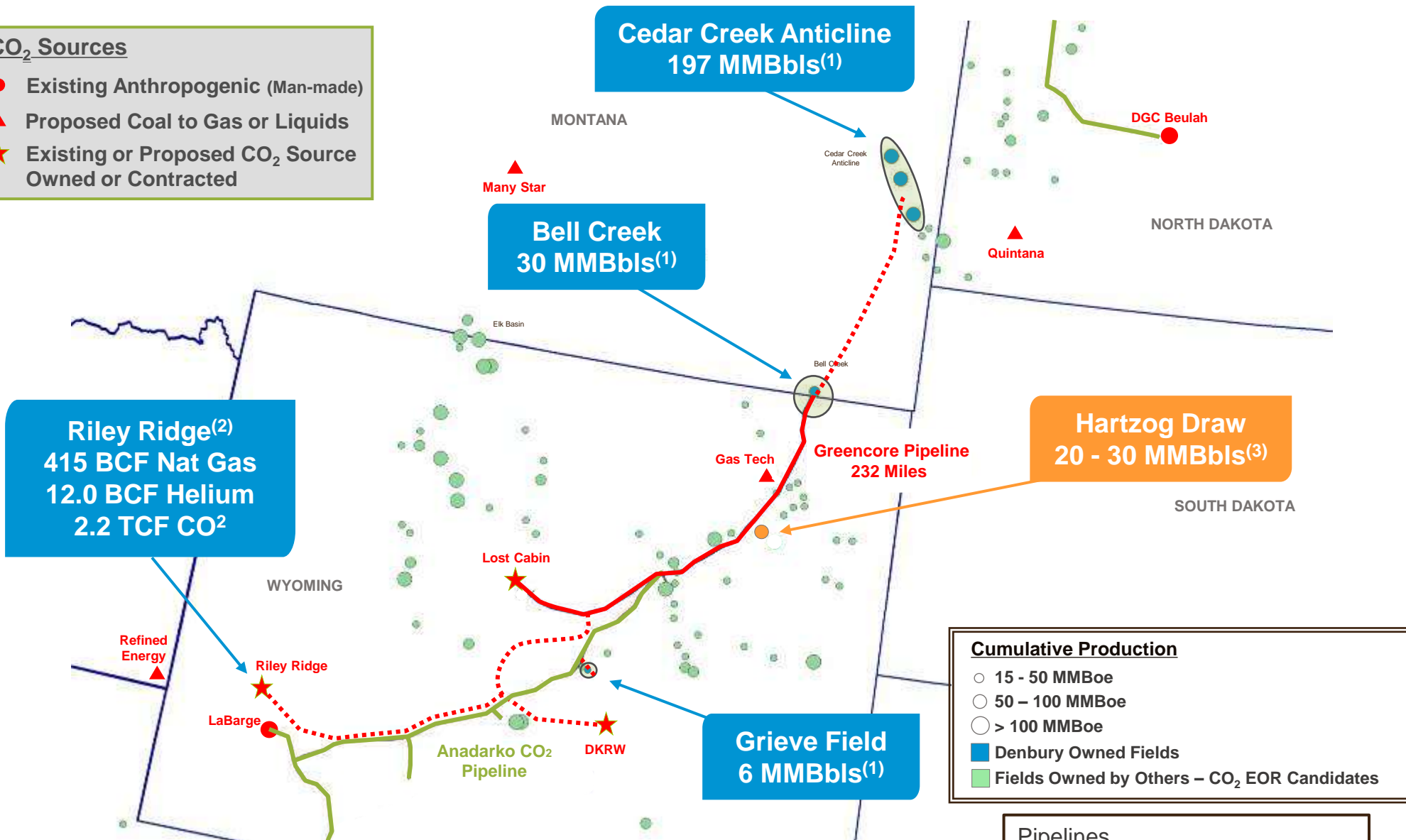
1) Proved plus probable tertiary oil reserves as of 12/31/11, rolled forward to 6/30/2012.
 2) Using mid-points of range, includes recently announced acquisition of Webster field.
 3) Acquired June 2012.
 4) Acquisition announced September 2012, expected to close in late 4Q 2012. See slide 8 for transaction details.

Rocky Mountain Region: Control of CO₂ Sources & Pipeline Infrastructure Provides a Strategic Advantage



CO₂ Sources

- Existing Anthropogenic (Man-made)
- ▲ Proposed Coal to Gas or Liquids
- ★ Existing or Proposed CO₂ Source Owned or Contracted



Cumulative Production

- 15 - 50 MMBoe
- 50 - 100 MMBoe
- > 100 MMBoe
- Denbury Owned Fields
- Fields Owned by Others – CO₂ EOR Candidates

Pipelines

- Denbury Pipelines in Process
- ⋯ Denbury Proposed Pipelines
- Pipelines Owned by Others

1) Probable and possible reserve estimates as of 12/31/11, based on a variety of recovery factors.
 2) Proved reserves as of 12/31/11
 3) Acquisition announced September 2012, expected to close late 4Q 2012. See slide 8 for transaction details.

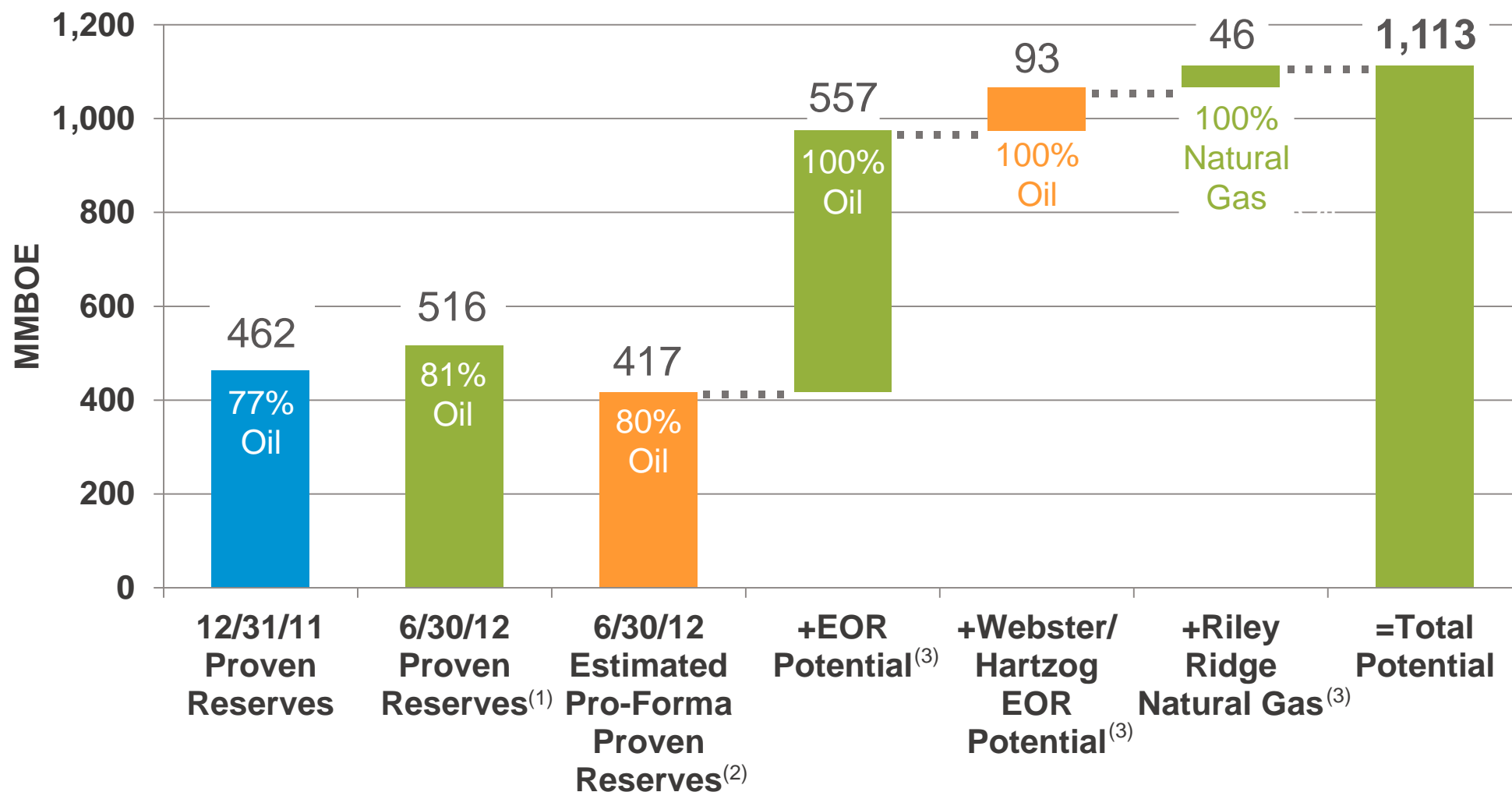


Transaction Terms

- Sell/Exchange Bakken assets for:
 - \$1.6 billion in cash proceeds (before closing adjustments and taxes)
 - Operating interest in Webster Field (SE Texas)⁽¹⁾
 - Operating interest in Hartzog Draw Field (NE Wyoming) ⁽¹⁾
- Expected to close late 4Q 2012, with a 7/1/2012 effective date
- Separately, we have agreed in principle to either purchase incremental CO₂ from XOM's LaBarge Field or purchase an interest in the CO₂ reserves from that field
- The purchase of an interest in CO₂ reserves would reduce the amount of cash received by Denbury

1) See appendix slides 40 and 41 for further information on these fields.

More than a Billion Barrels of Oil Potential



(1) Based on year-end 12/31/11 SEC proved reserves rolled forward for production, assets purchased and sold, incremental proved reserves for Hastings and Oyster Bayou and Bakken development, all through 6/30/12.

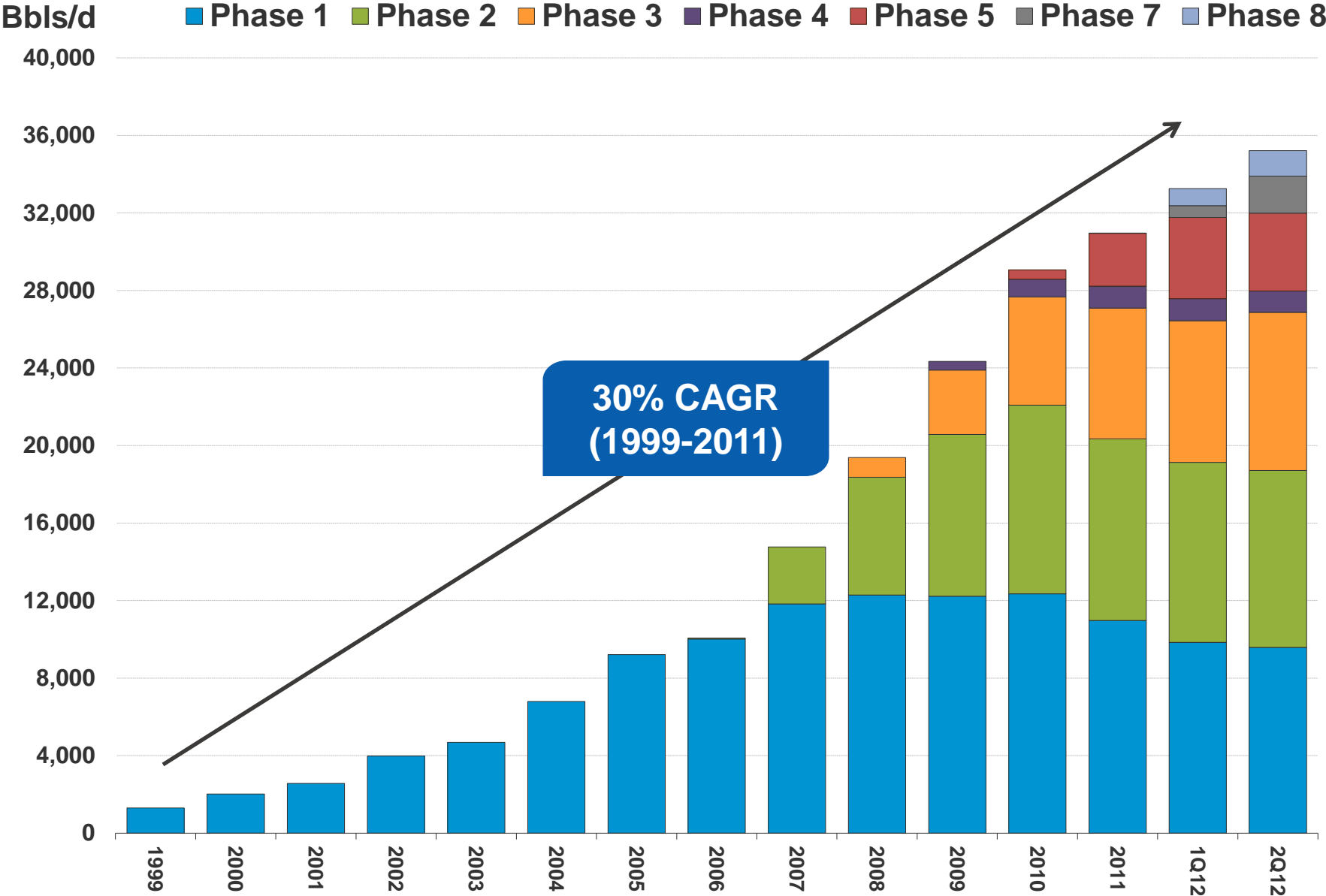
(2) Based on year-end 12/31/11 SEC proved reserves rolled forward for production, assets purchased and sold, incremental proved reserves for Hastings and Oyster Bayou, Bakken development, all through 6/30/12. Estimated pro-forma for Bakken sale and asset exchange, see slide 8 for transaction details.

(3) Estimates based on internal calculations, refer to slide 26 for additional disclosures.

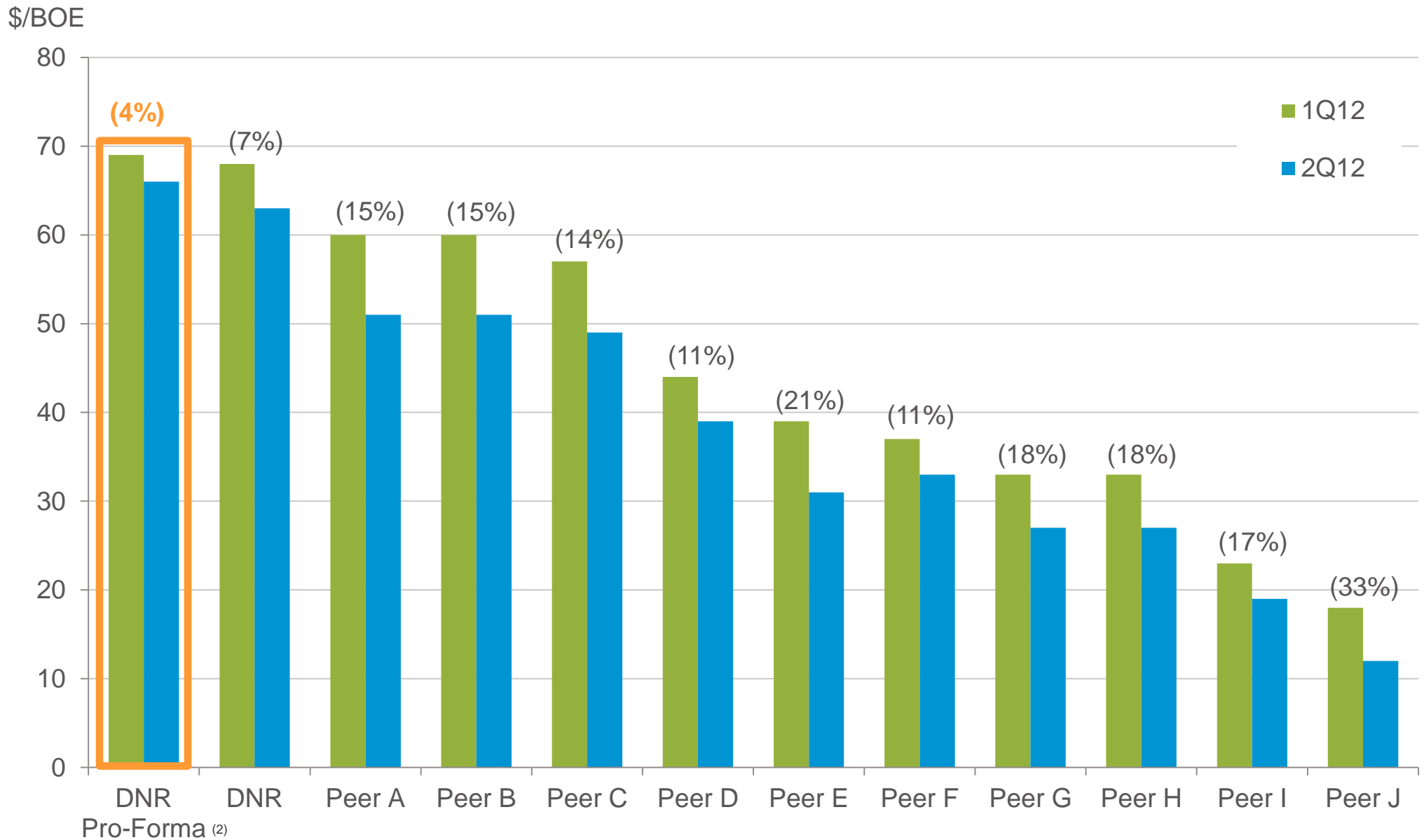
Proven Track Record



Net Daily Oil Production – Tertiary Operations (through 6/30/12)



Highest Operating Margin in the Peer Group (1)



(1) Data derived from SEC filings, 3 months ended 3/30/12 and 6/30/12, respectively and includes CLR, CXO, FST, NBL, NFX, PXD, RRC, SM, WLL, and XEC

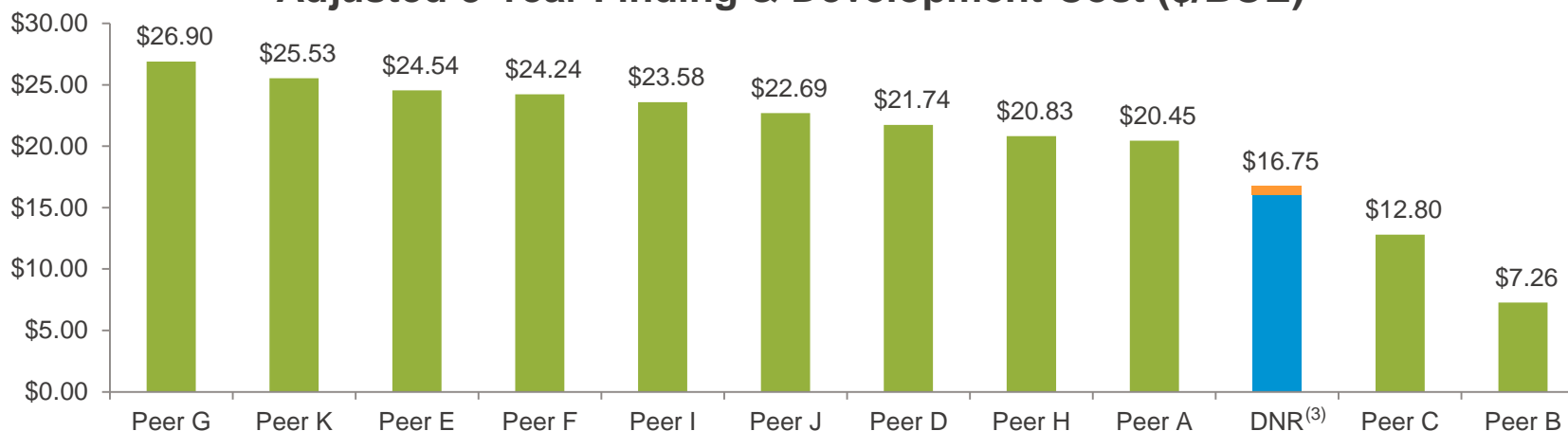
(2) Pro-forma for recently announced Bakken asset sale. See slide 8 for transaction details

Highest Capital Efficiency in Peer Group⁽¹⁾

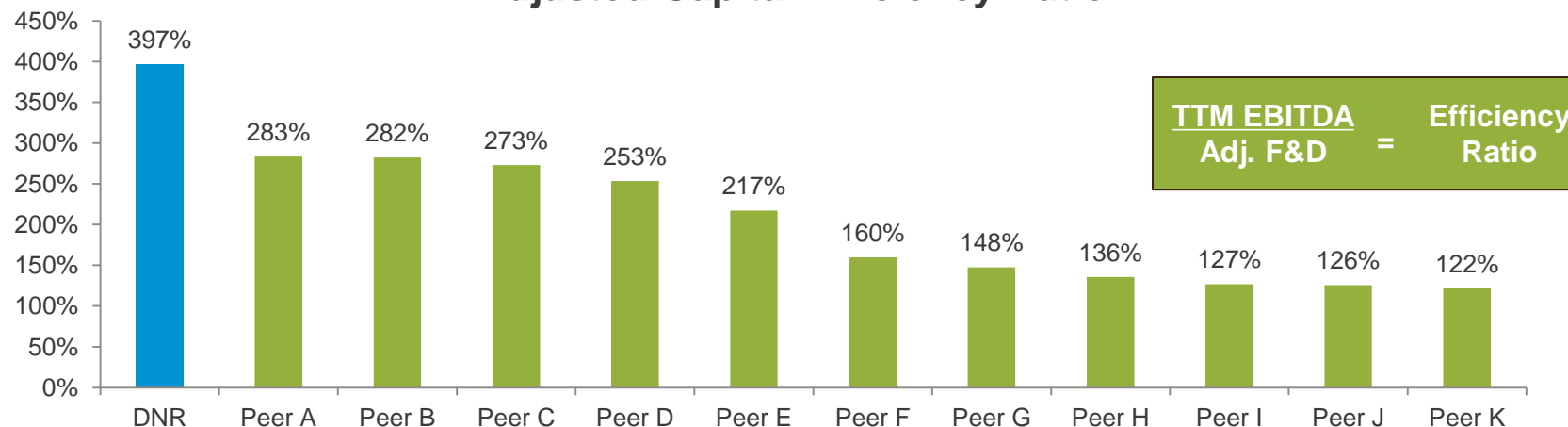
Does not include impact from recently announced Bakken sale and asset exchange



Adjusted 3-Year Finding & Development Cost (\$/BOE)⁽²⁾



Adjusted Capital Efficiency Ratio



(1) Peer Group includes CLR, CXO, FST, NBL, NFX, PXD, RRC, SD, SM, WLL, XEC

(2) Adjusted to include changes in future development costs and change in unevaluated properties.

(3) Includes 3 year average DD&A for CO₂ properties of \$0.83 per BOE

Compelling Economics⁽¹⁾



	EOR	Bakken
	Gulf Coast Model Averages	575,000 BOE / Well \$9.6 Million / Well⁽²⁾ 20% Royalty
NYMEX oil price	\$90.00	\$90.00
Finding & development cost:		
Field	9.00	21.00
Infrastructure	4.50	---
Total capital per BOE	\$13.50	\$21.00
Average operating cost over life	25.00	8.00
Average historic NYMEX differentials	1.25	10.00
Estimated gross margin	\$50.25	\$51.00
Estimated Internal Rate of Return	39%	27%
Return on investment	4.4	2.7

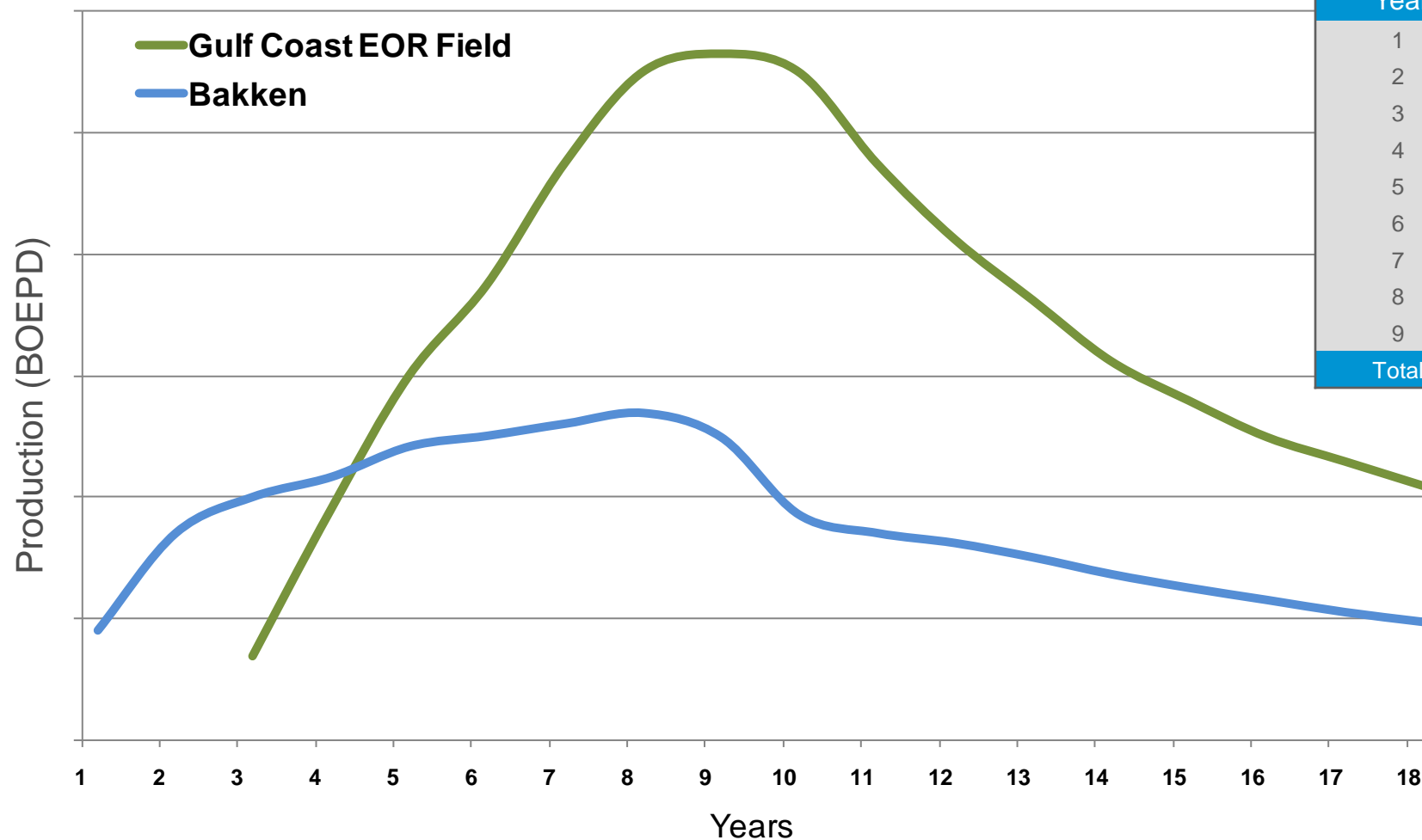
(1) Updated as of 12/31/11

(2) Cost target of long lateral well; Q1 actual cost averaged between \$10.5 to \$11.0 million

Complementary Production Profiles



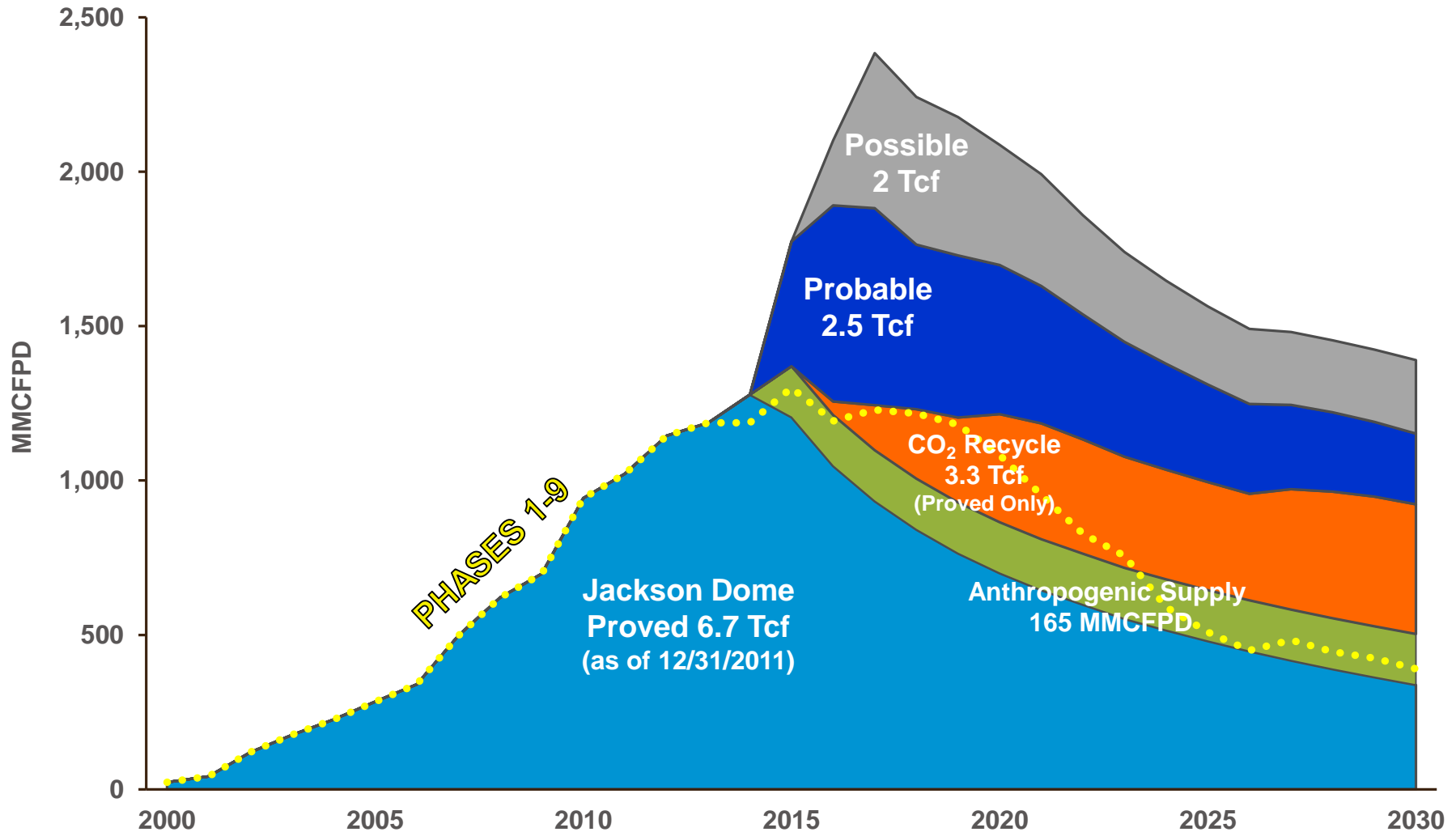
Projected Production Profile with Same Capital Spending



Capital Spending per Year Based on EOR Spending Pattern	
Year	\$MM
1	83
2	83
3	60
4	60
5	68
6	52
7	52
8	52
9	45
Total	\$555

Note: Assumes 700 BOEPD initial 30 day rate for Bakken wells.

Secure CO₂ Supply to Support Gulf Coast Growth



Note: CO₂ recycle assumed to be 50% of proved. Forecast based on internal management estimates. Actual results may vary. Phases 1-9 including industrial. Recently completed Thompson acquisition not included.

Secure CO₂ Supply to Support Rocky Mountain Growth



LaBarge Field

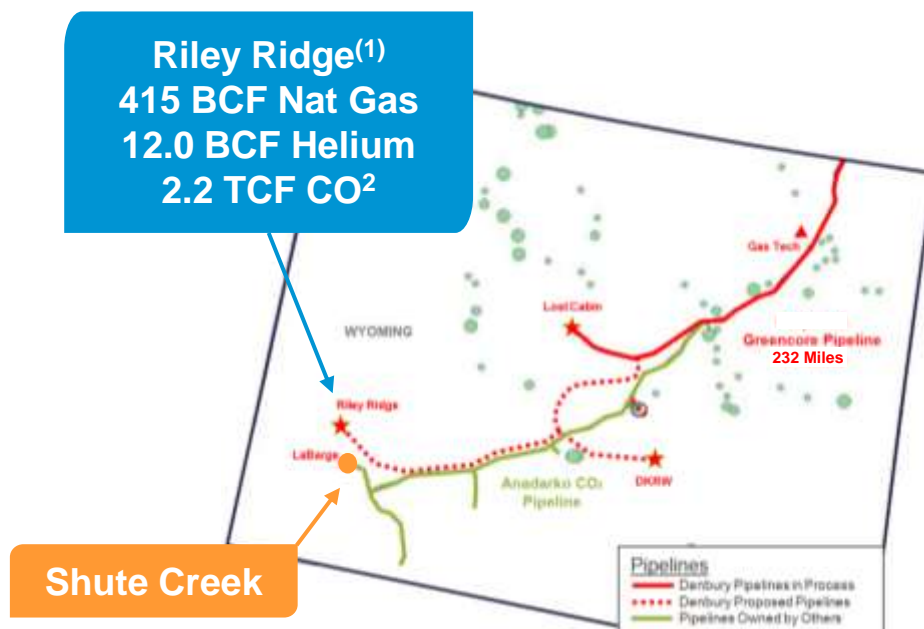
- Estimated Field Size: 750 Square Miles
- Estimated 100 TCF of CO₂ Recoverable

Riley Ridge – Denbury Operated

- 100% WI in 9,700 acre Riley Ridge Federal Unit
- 33% WI in ~28,000 acre Horseshoe Unit

Shute Creek – XOM Operated

- XOM has agreed in principle to either:
 - Sell up to 33% interest in CO₂ reserves – or –
 - Increase volume of CO₂ it will sell to Denbury under an existing sales contract
- Based on XOM's current plant capacity and availability, either option would allow for the delivery of up to 115 MMcf/d of CO₂



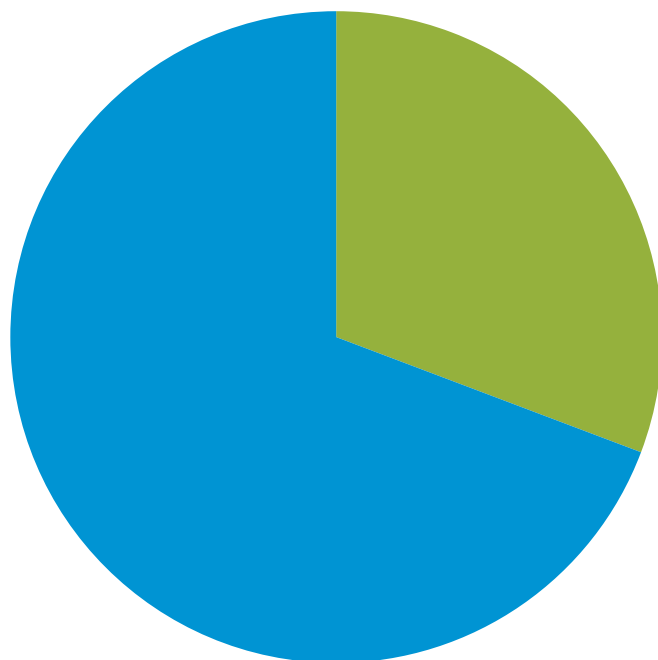
1) Proved reserves as of 12/31/2011

Strong Financial Position



- ~\$1.1 billion availability under credit facility on 6/30/12

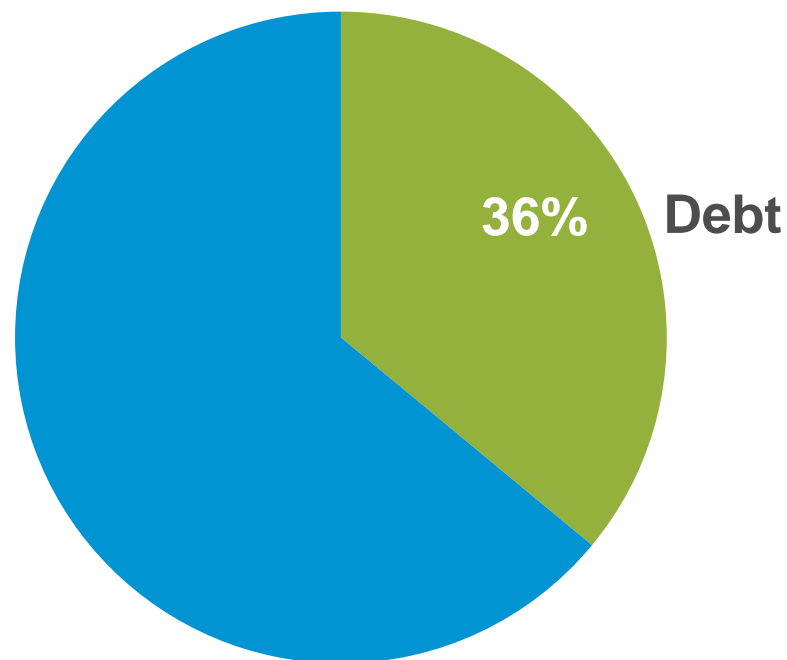
**Unused
Credit
Facility**



\$1.6 billion borrowing base

Net of cash, revolver debt of ~\$490 million at 6/30/12

**Debt to Capitalization
(6/30/12)**

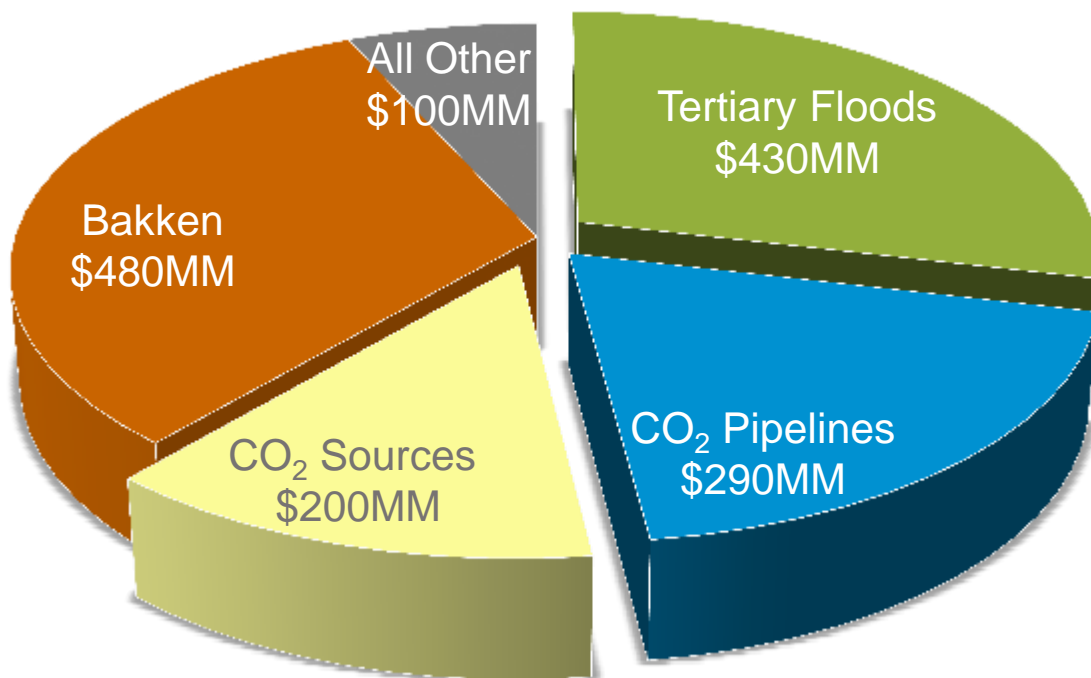


+ (6/30/12) Cash – \$28 million

2012 Summary Guidance⁽¹⁾



2012 Capital Budget – \$1.5 Billion⁽²⁾



2012 Production Estimate

Operating area	1Q12 (BOE/d)	2Q12 (BOE/d)	2012E (BOE/d)	2012E growth
Tertiary Oil Fields	33,257	35,208	33,000- 36,000	7-16%
Bakken	15,114	15,208	14,350- 16,350	63-86% ⁽⁴⁾
Total Continuing Production	69,770	72,280	69,350- 74,350	10-18%
Total Production⁽³⁾	71,532	72,337	69,775- 74,775	6-14%

Production per share will grow an additional ~3.5% in 2012 as a result of stock re-purchased to date

Currently expect tertiary and total production to be in the upper half of their respective ranges.

(1) Does not include impact of recently announced Bakken sale and asset exchange. See slide 8 for transaction details.

(2) Excludes capitalized interest and capitalized EOR startup costs, estimated at \$60 million, also net of estimated \$75 million funded with equipment leases

(3) Excludes production associated with divested properties completed in 2012.

(4) Recently announced divestiture of Bakken assets. See slide 8 for transaction details.

Hedges Protect Against Downside in Near-Term⁽¹⁾



Crude Oil ⁽²⁾	2012	2013				2014
	2 nd Half	1 st Quarter	2 nd Quarter	3 rd Quarter	4 th Quarter	1 st Half
Volumes hedged (Bbls/d) ⁽³⁾	54,250	55,000	56,000	56,000	54,000	46,000
Principal price support	\$80	~\$80	~\$80	~\$80	\$80	\$80
Principal price ceilings	~\$128	~\$108	~\$110	~\$110	~\$118	~\$103

Natural Gas	2012
Volumes hedged (Mcf/d) ⁽³⁾	20,000
Principal price support (primarily swaps)	\$6.30-6.85

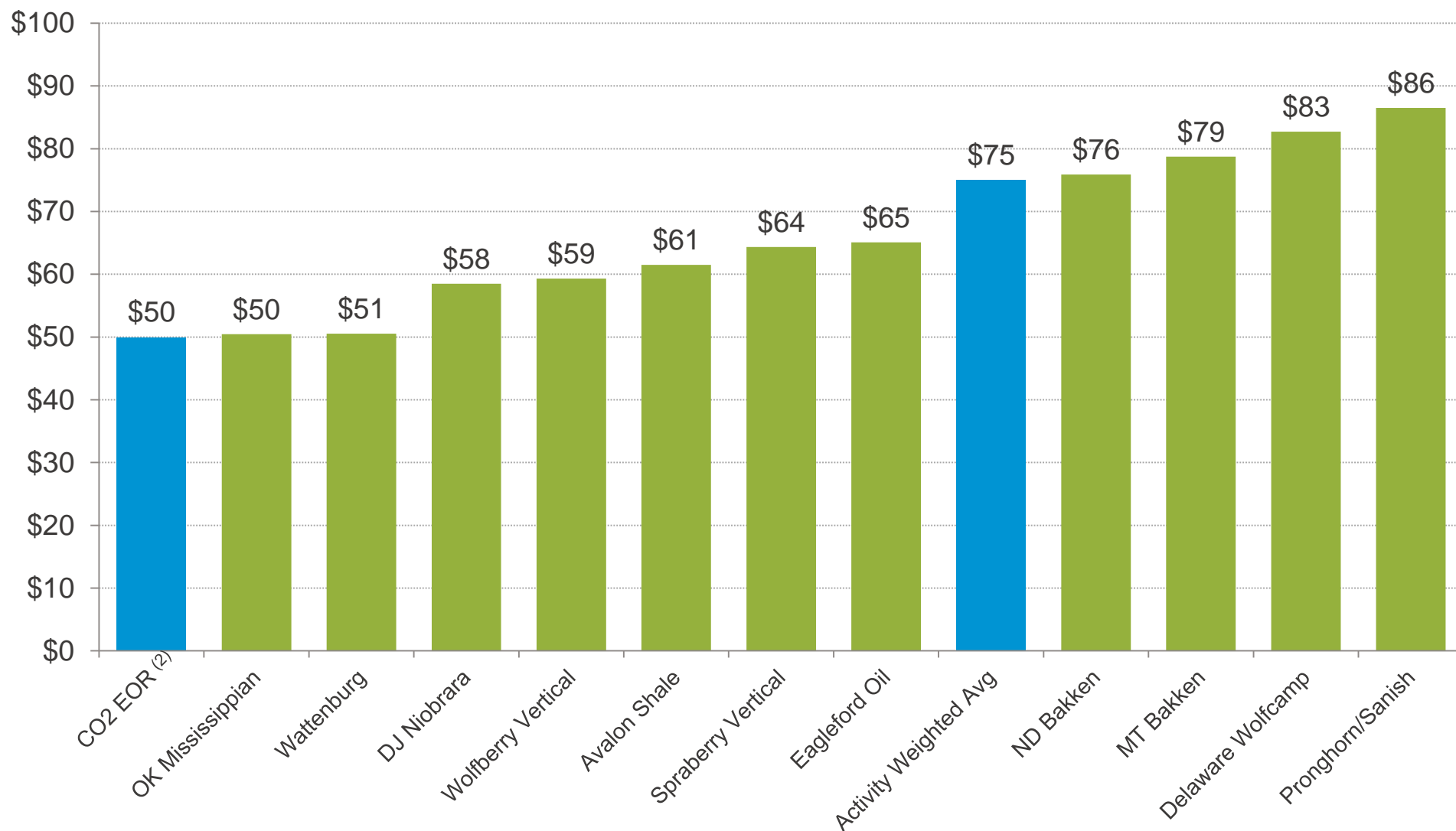
(1) Figures and averages as of 8/31/12. Please see slide 42 and SEC documents for details of derivative contracts.

(2) All crude oil derivative contracts are based on West Texas Intermediate (WTI) NYMEX price basis.

CO₂ EOR – Compelling Economics



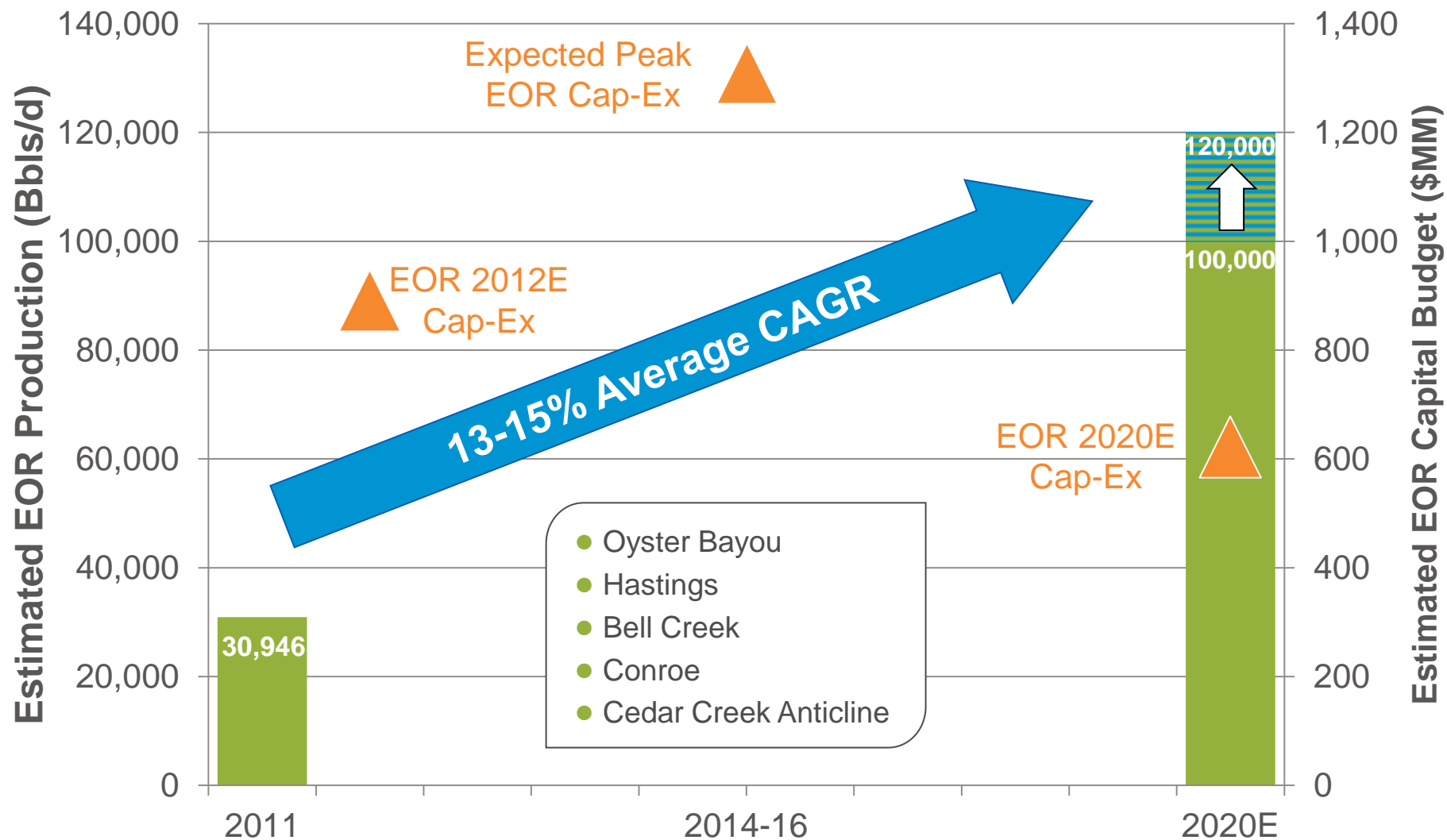
WTI Breakeven Price for a 15% After-Tax Rate of Return (\$ per Bbl)⁽¹⁾



(1) Source: ISI Group report dated June 15, 2012. Defined as the threshold WTI oil price necessary to generate a 15% after-tax rate of return. Excludes acreage costs.

(2) Internal estimate for indicative large CO₂ EOR development project in the Gulf Coast Region.

Sustainable EOR Growth through 2020 (1)



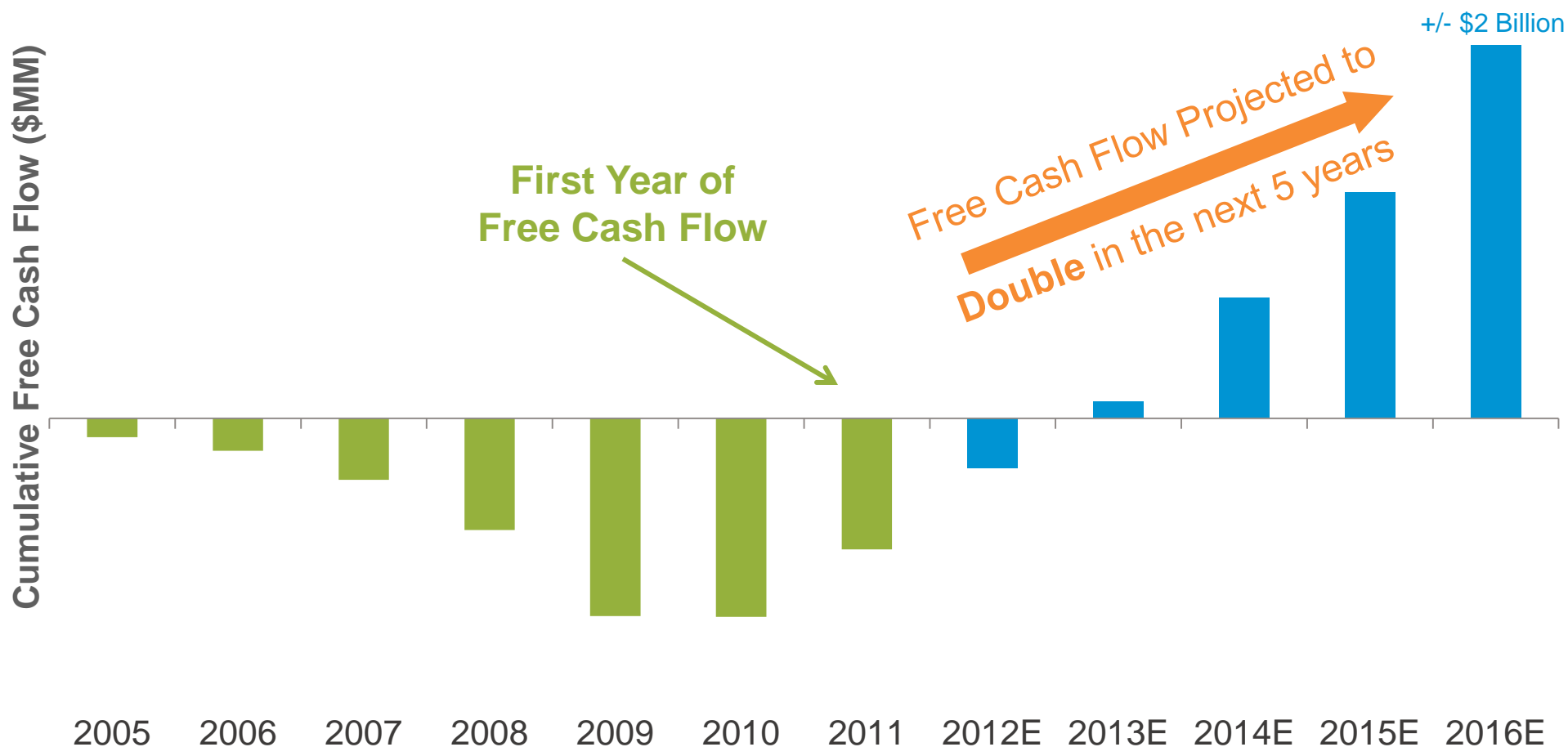
Does not include Thompson, Hartzog Draw or Webster

(1) 2012 and future forecasted capital expenditures and production may differ materially from actual results. See slide 26 for full disclosure.

CO₂ EOR Generates Significant Free Cash Flow



Cumulative Gulf Coast Tertiary Free Cash Flows⁽¹⁾



Does not include Thompson, Hartzog Draw or Webster

(1) Calculated from actual historical operating cash flow (revenues less operating expenses) less capital expenditures and currently projected operating income and capital expenditures in 2012 and beyond using strip prices as of 5/4/2012. Includes Jackson Dome and Pipeline expenditures in Gulf Coast, does not include recently completed Thompson acquisition. See slide 26 for full disclosure of forward-looking statements.

Estimated EOR Peak Production Rates (as of 12/31/11)



Operating Area	First Production	Estimated Peak Production Rate (Net MBOE/d)					Expected Peak Year	Produced to date ⁽¹⁾ (MMBOE)	Proved Remaining ⁽¹⁾ (MMBOE)	2P&3P Remaining ⁽²⁾ (MMBOE)
		< 5	5-10	10-15	15-20	> 20				
Phase 1	1999			🔴			2010	36	35	11
Phase 2 (excl Heidelberg)	2006		🔴				2015-17	11	16	12
Oyster Bayou	2012	🔴					2012-13	<1	14	11
Tinsley	2008						2013-14	6	31	9
Heidelberg	2009		🔴				2014-16	2	31	11
Delhi	2010		🔴				2015-17	1	27	8
Bell Creek	2013		🔴				2018-20	---	---	30
Cranfield	2009			🔴			2016-19	1	8	6
Lake Saint John	2016	🔴					2018-22	---	---	18
Hastings	2012				🔴		2021-25	<1	43	32
Citronelle	Unscheduled	🔴					>2020	---	---	26
Conroe	2015				🔴		2022-26	---	---	130
Cedar Creek Anticline	2017				🔴		2023-27	---	---	197
Thompson		To Be Determined						---	---	45
Hartzog Draw		To Be Determined						---	---	25
Webster		To Be Determined						---	---	68

Expected year of first tertiary production.

- (1) Tertiary oil production and reserves as of 12/31/11, except for Oyster Bayou and Hastings at which proved reserves were recorded in the first and second quarters of 2012, respectively.
- (2) Based on internal estimates of reserve recovery, using mid-points of ranges.

IN SUMMARY: A Different Kind of Oil Company



Leading CO₂ Enhanced Oil Recovery (EOR) Company in the U.S. with a Unique Profile

- Significant strategic advantage in CO₂ EOR
- Well defined and focused long-term growth strategy
- Highest operating margin and capital efficiency in peer group
- Substantial free cash flow generation from CO₂ EOR after up-front investment in infrastructure
- CO₂ EOR provides high degree of capital flexibility
- Low stock price relative to net asset value





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About Forward Looking Statements



The data contained in this presentation that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things, forecasted capital expenditures, drilling activity, acquisition and dispositions plans, development activities, timing of CO₂ injections and initial production response in tertiary flooding projects, estimated costs, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO₂ reserves, helium reserves, potential reserves from tertiary operations, future hydrocarbon prices or assumptions, liquidity, cash flows, availability of capital, borrowing capacity, finding costs, rates of return, overall economics, net asset values, potential reserves and anticipated production growth rates in our CO₂ models, 2012 and future production and expenditure estimates, and availability and cost of equipment and services. These forward-looking statements are generally accompanied by words such as “estimated”, “preliminary”, “projected”, “potential”, “anticipated”, “forecasted” or other words that convey the uncertainty of future events or outcomes. These statements are based on management’s current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent Form 10-K and Form 10-Q filed with the SEC. Therefore, the actual results may differ materially from the expectations, estimates or assumptions expressed in or implied by any forward-looking statement made by or on behalf of the Company.

Cautionary Note to U.S. Investors – Current SEC rules regarding oil and gas reserve information allow oil and gas companies to disclose in filings with the SEC not only proved reserves, but also probable and possible reserves that meet the SEC’s definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury’s proved reserves as of December 31, 2011 were estimated by DeGolyer & MacNaughton, an independent petroleum engineering firm. In this presentation, we make reference to probable and possible reserves, some of which have been prepared by our independent engineers and some of which have been prepared by Denbury’s internal staff of engineers. In this presentation, we also refer to estimates of original oil in place, resource “potential” or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible (2P and 3P reserves), include estimates of reserves that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

Appendix



CO₂ EOR is a Proven Process



Significant CO₂ EOR Operators by Region

Gulf Coast Region

- Denbury Resources

Permian Basin Region

- Occidental
- Kinder Morgan
- Whiting

Rockies Region

- Denbury Resources
- Anadarko

Canada

- Cenovus
- Apache

Significant CO₂ Suppliers by Region

Gulf Coast Region

- Jackson Dome, MS (Denbury Resources)

Permian Basin Region

- Bravo Dome, NM (Kinder Morgan, Occidental)
- McElmo Dome, CO (ExxonMobil, Kinder Morgan)
- Sheep Mountain, CO (ExxonMobil, Occidental)

Rockies Region

- Riley Ridge, WY (Denbury Resources)
- LaBarge, WY (ExxonMobil)
- Lost Cabin, WY (ConocoPhillips)

Canada

- Dakota Gasification – Anthropogenic (Cenovus, Apache)

History of CO₂ EOR

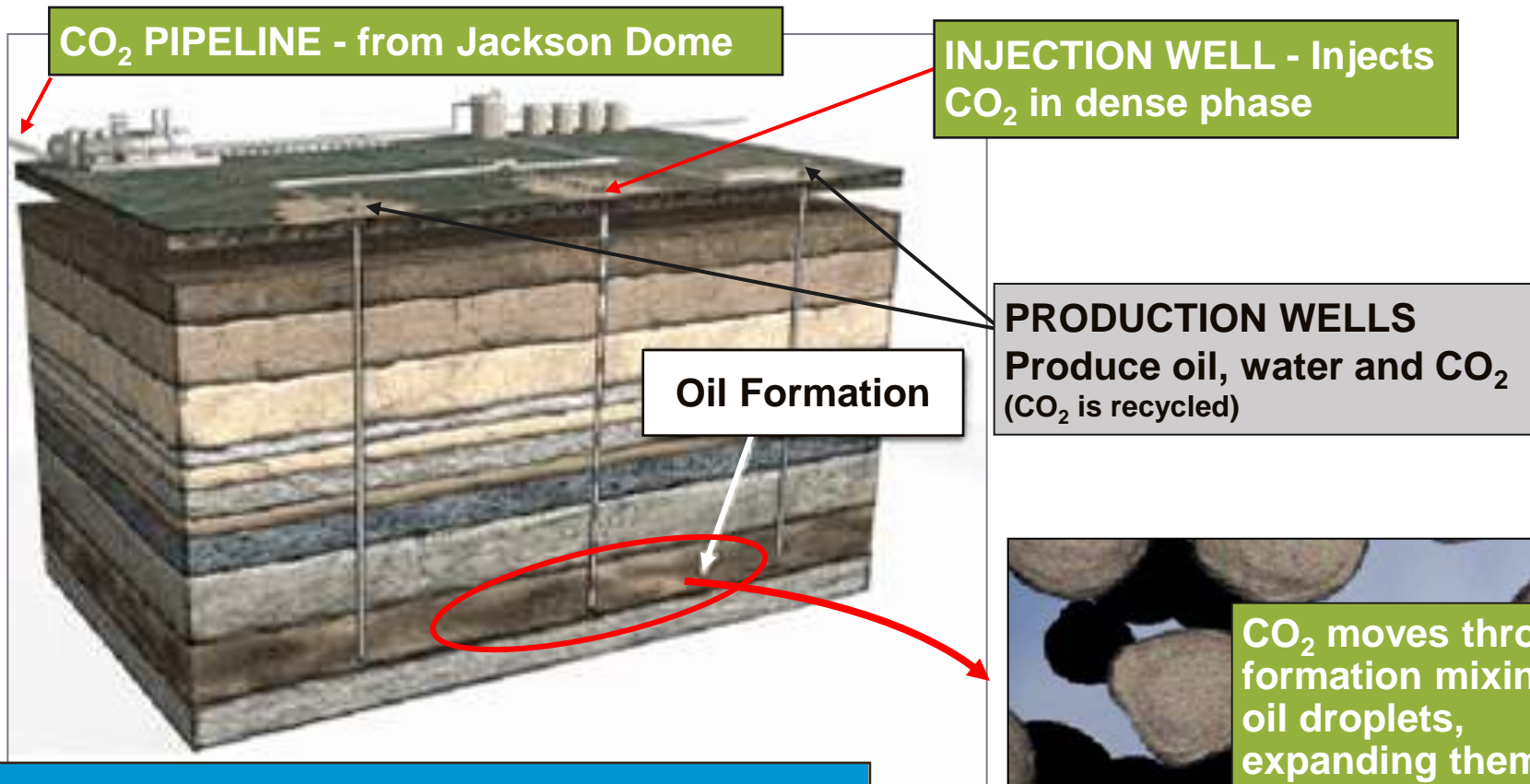
- 1910's-1970's – CO₂ Field Discoveries (Bravo Dome, McElmo Dome, Jackson Dome, Sheep Mountain)
- 1950's-1960's – Development & Testing
- 1972 – First Notable CO₂ EOR Flood in Permian Basin (SACROC)
- 1973 – First Notable CO₂ EOR Flood in Gulf Coast (Little Creek)
- 1986 – First Notable CO₂ EOR Flood in Rockies (Rangely)
- 2000 – First Anthropogenic CO₂ EOR Flood (Weyburn/Canada)

Denbury is the 2nd Largest CO₂ EOR Producer in North America⁽¹⁾



(1) Based on net production interests from company filings for quarter ended 3/31/2012.

CO₂ Operations: Oil Recovery Process



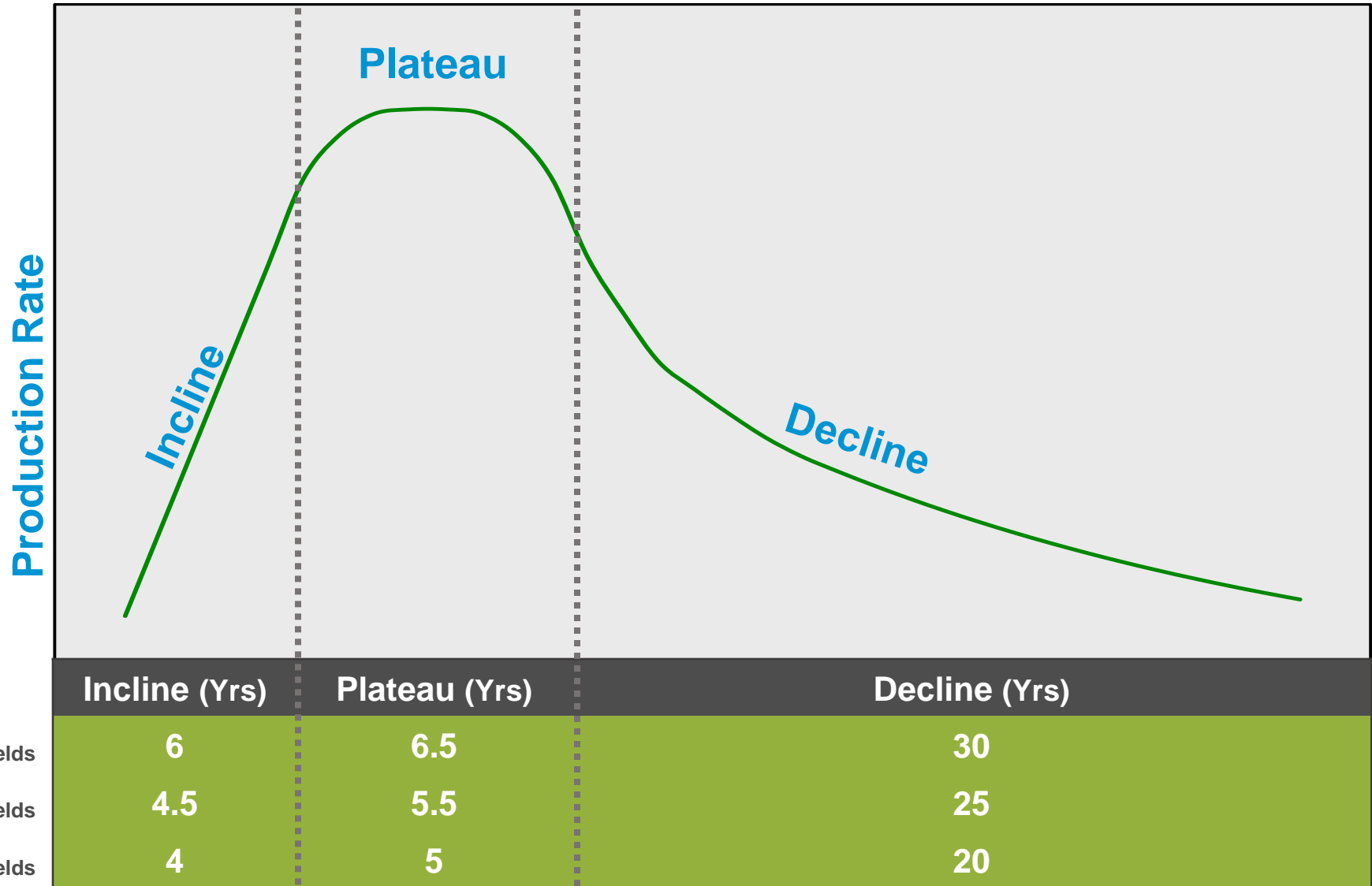
Model for Oil Recovery Using CO₂ is +/- 17% of Original Oil in Place (Based on Little Creek)

Primary recovery = +/- 20%

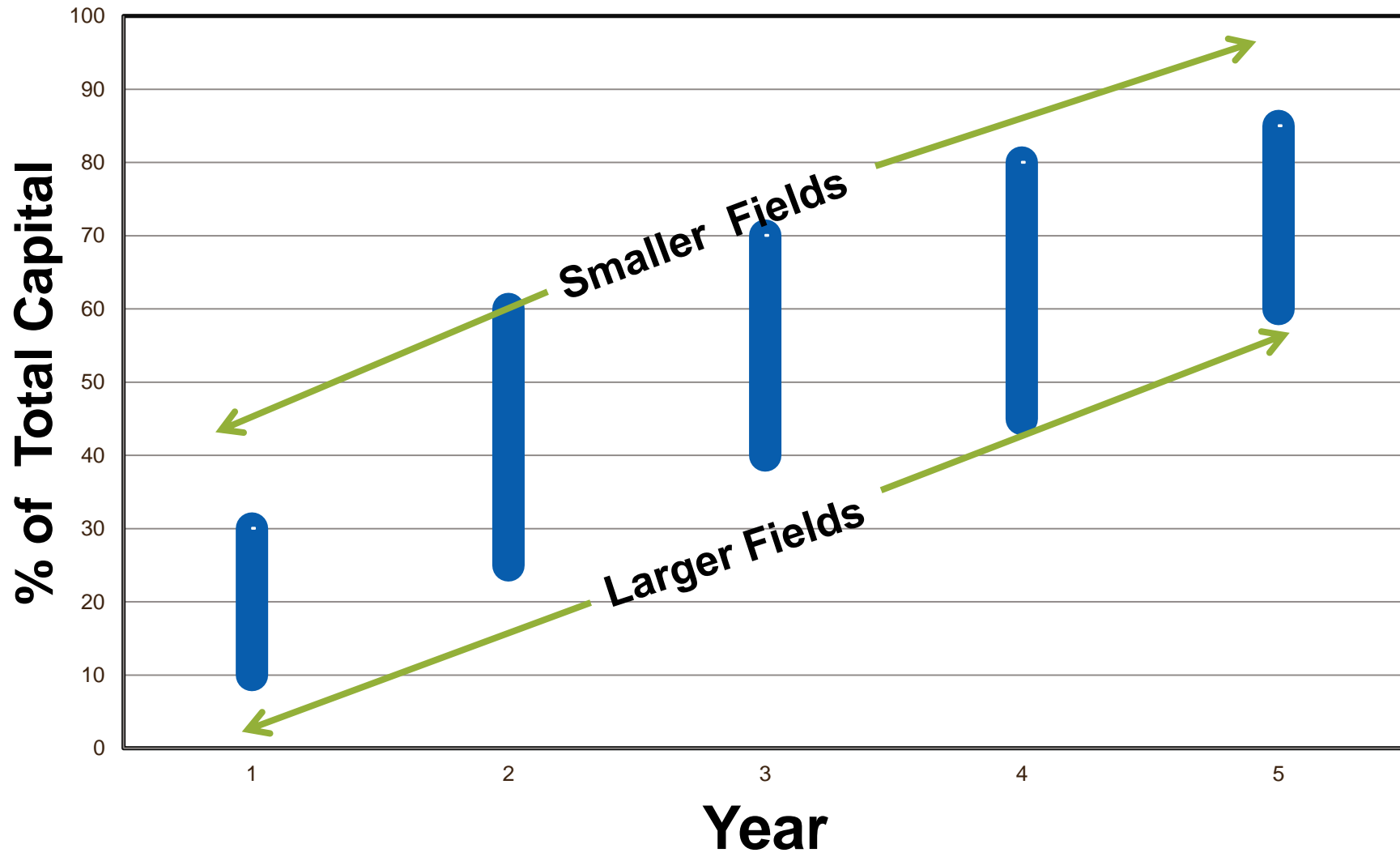
Secondary recovery (waterfloods) = +/- 18%

Tertiary (CO₂) = +/- 17%

CO₂ EOR Generalized Type Curve



Capital Spending Range for CO₂ Floods





Unique characteristics of CO₂ EOR provides significant capital flexibility

- We attempt to balance development expenditures with free cash flow
- In contrast to shale plays, a reduction in EOR capital spending will not immediately impact EOR production growth
- Our newer EOR projects have many years of production growth with fairly low capital expenditures
- It is relatively easy to slow the development pace of EOR projects - most Rocky Mountain EOR infrastructure development could be delayed if necessary
- No lease expiration issues and limited capital commitments on EOR projects beyond 2012

Production by Area (BOE/d) ⁽¹⁾



Operating area	2Q11	3Q11	4Q11	2011	1Q12 ⁽²⁾	2Q12 ⁽²⁾	2012E ^{(2),(3)}
Tertiary Oil Fields	30,771	31,091	31,144	30,959	33,257	35,208	33,000 - 36,000
Mississippi	5,642	5,636	4,746	5,486	4,573	4,095	4,450
Texas	4,202	4,096	3,868	4,133	3,674	4,573	4,650
Louisiana	454	47	141	287	191	189	150
Alabama & Other	1,079	1,064	1,031	1,049	1,090	1,117	950
Cedar Creek Anticline	8,925	8,930	8,858	8,968	8,496	8,535	8,300
Bakken	7,626	9,976	11,743	8,788	15,114	15,208	14,350- 16,350 ⁽⁴⁾
Other Rockies	3,629	3,578	3,373	3,520	3,375	3,355	3,500
Total Continuing Production	62,328	64,418	64,904	63,190	69,770	72,280	69,350 - 74,350
Gulf Coast Non-Core Properties	1,901	1,732	1,677	1,805	1,054	---	250
Paradox Basin Properties	690	680	653	665	708	57	175
Total Production	64,919	66,830	67,234	65,660	71,532	72,337	69,775 - 74,775
							~93% Oil

(1) Does not include impact from recently announced Bakken sale and asset exchange. See slide 8 for transaction details.

(2) In February and April 2012, we sold non-core Gulf Coast and Paradox Basin assets in separate transactions for combined net proceeds of \$213 million. The combined average annual production from with these assets in 2012 was estimated at 2,050 BOE/d. Due to their contribution to our production during the period we owned them in 2012, the sale reduced our 2012 average annual production estimates by 1,625 BOE/d.

(3) In June 2012 we acquired Thompson field for \$360 million, before working capital adjustments. Expected average production from the assets for the remainder of 2012 is estimated at 2,000 BOE/d. The acquisition increased our 2012 average annual production estimates by 1,150 BOE/d as the acquired assets will only contribute to our production for approximately seven months in 2012.

(4) Recently announced divestiture of Bakken assets. See slide 8 for transaction details.

Tertiary Production by Field



Field	Average Daily Production (BOE/d)				
	2Q11	3Q11	4Q11	1Q12	2Q12
Phase 1					
Brookhaven	3,213	3,030	3,121	3,014	2,779
Little Creek Area	1,636	1,533	1,445	1,216	1,131
Mallalieu Area	2,646	2,620	2,587	2,585	2,461
McComb Area	1,983	2,005	1,843	1,746	1,902
Lockhart Crossing	1,560	1,346	1,304	1,284	1,313
Phase 2					
Martinville	416	453	481	551	480
Eucutta	3,114	2,985	3,139	3,090	2,870
Soso	2,317	2,331	2,162	2,063	1,947
Heidelberg	3,548	3,141	3,728	3,583	3,823
Phase 3					
Tinsley	6,990	7,075	6,338	7,297	8,168
Phase 4					
Cranfield	1,085	1,214	1,200	1,152	1,094
Phase 5					
Delhi	2,263	3,358	3,778	4,181	4,023
Phase 7					
Hastings	---	---	---	618	1,913
Phase 8					
Oyster Bayou		---	18	877	1,304
Total Tertiary Production	30,771	31,091	31,144	33,257	35,208

Analysis of Tertiary Operating Costs



	Correlation w/Oil	2Q10 \$/Bbl	3Q10 \$/Bbl	4Q10 \$/Bbl	1Q11 \$/Bbl	2Q11 \$/Bbl	3Q11 \$/Bbl	4Q11 \$/Bbl	1Q12 \$/Bbl	2Q12 \$/Bbl
CO ₂ Costs	Direct	\$4.73	\$4.52	\$5.38	\$5.39	\$5.43	\$4.87	\$4.53	\$5.76	\$5.14
Power & Fuel	Partially	5.82	6.03	5.76	6.12	6.17	6.24	6.71	6.71	6.69
Labor & Overhead	None	3.50	3.70	3.43	3.94	3.77	3.85	3.90	4.59	4.64
Equipment Rental	None	2.02	1.93	1.79	2.20	1.52	2.28	2.38	2.30	0.15
Chemicals	Partially	1.41	1.73	1.67	1.62	1.44	1.80	1.67	1.63	1.27
Workovers	Partially	1.62	2.78	2.36	3.75	2.53	3.44	2.68	3.43	3.01
Other	None	1.56	1.68	1.34	1.91	2.01	2.43	1.72	2.32	2.05
Total		\$20.66	\$22.37	\$21.73	\$24.93	\$22.87	\$24.91	\$23.59	\$26.74	\$22.95
NYMEX Oil Price		\$78.12	\$76.10	\$85.16	\$94.26	\$102.58	\$89.60	\$93.93	\$102.87	\$93.49

(1) Due to a change in classification of equipment leases, tertiary lease operating expense were reduced by \$2.57/bbl in the second quarter.

Potential Carbon Gasification Projects



- Denbury purchase contracts (contingent on plants being completed)
 - Initial production expected +/- 4 years after construction begins (not before 2015)

Gulf Coast Sources (\$0.29 to \$0.44/Mcf @ \$60 Oil)		MMCFD
Mississippi Power ⁽⁴⁾ (2014)	<i>Currently Under Construction</i>	+/- 115
Air Products (Port Arthur, TX) ⁽⁴⁾ (Q1 2013)		50
Lake Charles Cogeneration LLC ⁽³⁾		190 – 240
Mississippi Gasification (SNG) ⁽¹⁾ ⁽²⁾ ⁽³⁾		170 – 225

Midwest Sources (\$0.20/Mcf @ \$60 Oil)		MMCFD
Indiana Gasification (SNG) ⁽¹⁾ ⁽²⁾		230 – 300
Power Holdings of Illinois (SNG) ⁽¹⁾		250 – 300
Christian County Generation/Tenaska of Illinois (SNG) ⁽¹⁾ ⁽²⁾ ⁽⁵⁾		170 – 225
Cash Creek Kentucky (SNG) ⁽¹⁾		190 – 210

(1) Requires additional supplies and additional pipeline.

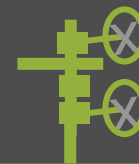
(2) In term sheet negotiation phase under the U.S. Department of Energy Loan Guarantee Program.

(3) Denbury and Producer selected for DOE Grant FOA-0000015 (grant dollars, not loan guarantees).

(4) Under Construction

(5) Contingent on having pipeline capacity.

Rockies Anthropogenic CO₂



Rocky Mountain Purchase Contracts		MMCFD
COP Lost Cabin (Central Wyoming) (Q1 2013)	<i>Currently Under Construction</i>	+/- 50
XOM LaBarge (SW Wyoming) ⁽¹⁾ (Q3 2012)		+/- 50
DKRW Medicine Bow (SE Wyoming) ⁽²⁾ (+/- 2016)		+/- 100

Rocky Mountain CO ₂ Ownership	MMCFD
Riley Ridge Unit - LaBarge (SW Wyoming) (2016)	+/- 130⁽⁴⁾

Rocky Mountain Potential Sources	MMCFD
GasTech (NE Wyoming)	+/- 115
Quintana South Heart Project (SW North Dakota)	+/- 100
Dakota Gasification (SW North Dakota) ⁽³⁾	+/- 250

(1) Grieve Field Contract – Potential for more XOM supply.

(2) In term sheet negotiation phase under the U.S. Department of Energy Loan Guarantee Program.

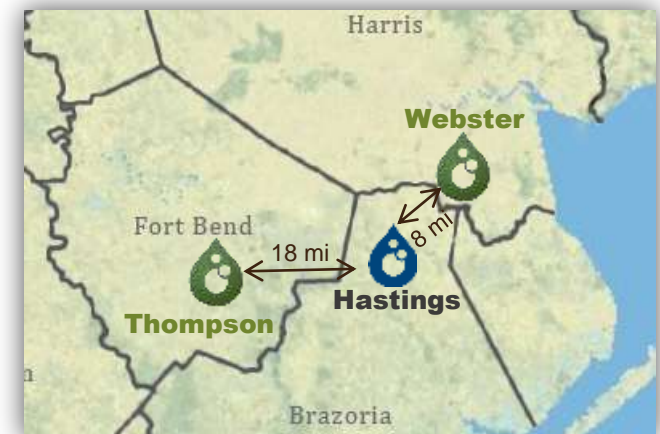
(3) Includes volumes currently under contract by third parties

(4) Initial capacity, potential to increase to +/- 600 MMCFD by 2021

Webster Field – Southeastern Texas



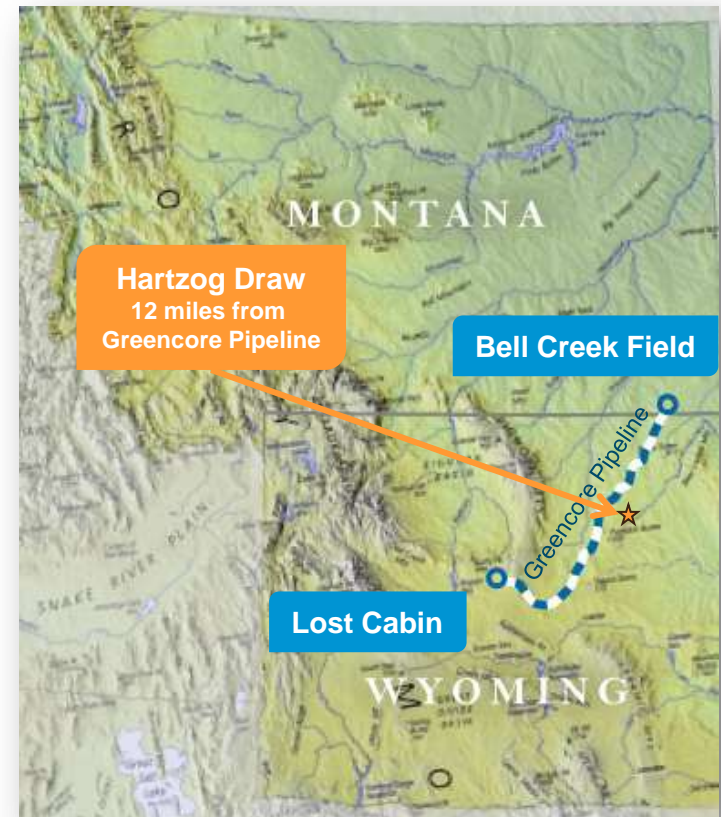
- Acquisition expected to close late 4Q 2012
- Denbury will be the operator with a 99.4% working interest
- Discovered in 1937 by Humble oil with a peak production in the 1970's at over 67,000 barrels per day.
- Produces from the same zones as Hastings
- ~550 million barrels of Original Oil in Place in zones targeted for CO₂ EOR, with ultimate potential net recovery of 60-75 million barrels of oil
- Requires ~8 mile CO₂ pipeline from Green Pipeline
- Currently producing ~1,000 boe/day net (86% oil)
- Conventional (non-tertiary) reserves ~3 million boe



Hartzog Draw Field – Northeastern Wyoming



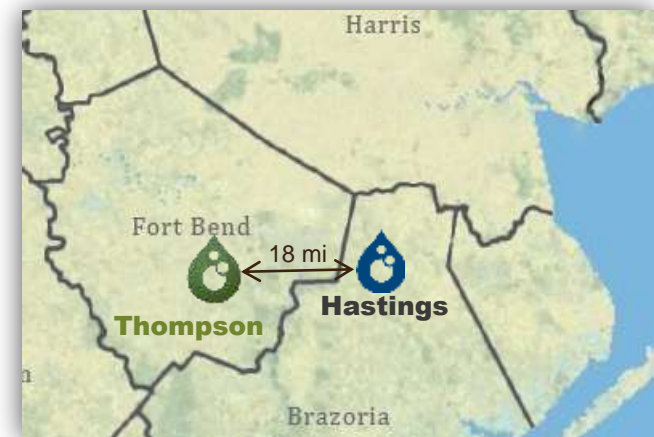
- Acquisition expected to close late 4Q 2012
- Denbury will be the operator with an:
 - 83% working interest in the oil producing Shannon Sandstone zone, and a
 - 67% working interest in the natural gas producing Big George Coal zone
- Discovered in 1975 by City Services Oil Company with peak production in 1978 at over 35,000 barrels per day.
- ~370 million barrels of Original Oil in Place, with ultimate potential net recovery by CO₂ EOR of 20-30 million barrels of oil
- Requires about ~12 mile CO₂ pipeline from Greencore pipeline
- Currently producing ~2,600 boe/day net (52% oil)
- Conventional (non-tertiary) reserves ~7 million boe



Thompson Field, Fort Bend County, Texas



- Acquired in June 2012 for \$366 million cash⁽¹⁾
- Denbury is the operator with a nearly 100% working interest and 84.7% net revenue interest
- Original oil in place of ~650 MMBbls, with zones initially targeted for CO₂ flood estimated to have ~300 MMBbls of OOIP
- Potential tertiary oil reserves between 30-60 MMBbls (based on recovery factor from other Gulf Coast CO₂ floods)
- Requires ~18 mile CO₂ pipeline from Green Pipeline
- Estimated 2012 development costs ~\$12 million
- Estimated average production for remainder of 2012 of 2,000 net BOPD
- Proved reserves of 12.3 MMBbls as of 6/30/12
 - Estimated potential of additional 5 MMBbls of conventional reserves



(1) The seller retained an approximate 5% gross revenue interest (less severance taxes) beginning when average monthly production exceeds 3,000 bbls/d after the initiation of CO₂ injection.

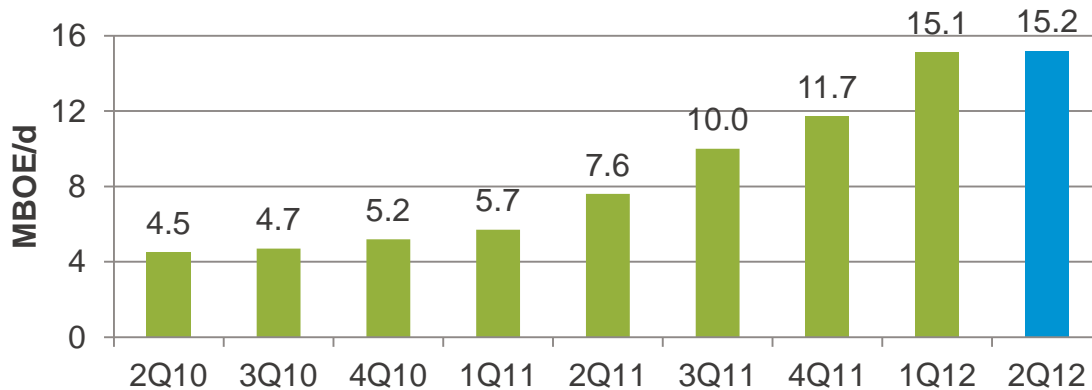
Bakken Area⁽¹⁾



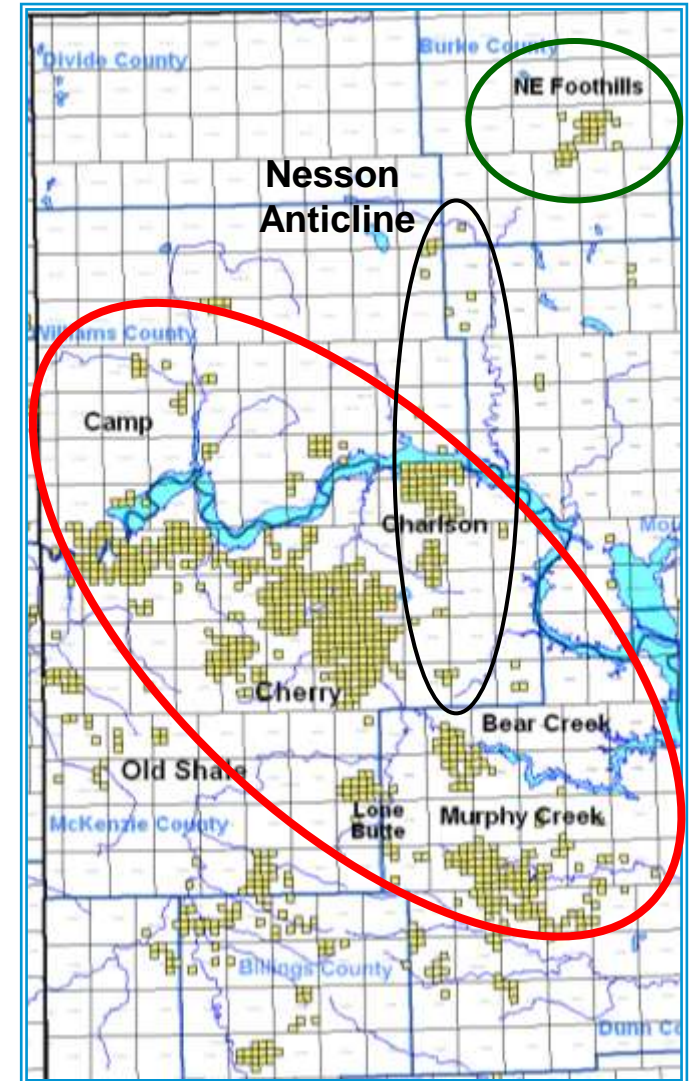
Bakken Area

- ~200,000 net acres
- ~300 MMBOE of total potential
 - ~107 MMBOE Proved as of 6/30/2012
- 2011 Production – 8,788 BOE/d
- 2Q12 Production – 15,208 BOE/d
 - 99% increase vs. 2Q11
- 2012E Production – 14,350-16,350 BOE/d

Net Bakken Production



(1) Recently announced divestiture of Bakken assets. See slide 8 for transaction details.



○ Denbury's Core Bakken Area ○ Denbury's Extensional Bakken Areas
● DNR Acreage

Bakken Area Production Zones



Area	Productive Zone		Estimated Wells/DSU	Approx. Net Acreage
	MB	TFS		(1,000's)
Charlson	✓	✓	6	15
Murphy Creek	✓	✓	6	18
Bear Creek	✓	✓	6	10
Cherry	✓	✓	6	66
Lone Butte	✓	✓	6	9
Camp/Indian Hills	✓	?	6	16
NE Foothills	✓	?	3	10
Old Shale Play	✓	✓	6	46
Montana & Other Areas	✓	?	3	12
Total				202

Crude Oil & Natural Gas Hedge Detail



2012 Crude Oil Hedges (BOPD) ⁽¹⁾

Instrument	Volume	Average ⁽²⁾		Ceiling		
		Price	Floor	Ceiling	Low	High
H2 Collars	12,000		80.00	124.54	123.00	125.62
	24,000		80.00	127.70	126.25	129.35
	14,000		80.00	131.04	130.00	132.75
	3,000		80.00	140.13	139.10	140.65
Put	625		65.00			
Swap	625	81.04				

2012 Natural Gas (MCFD)

Instrument	Volume	Average ⁽²⁾		Low	High
		Price			
FY12 Swaps	7,000	6.31		6.30	6.35
	11,000	6.62		6.60	6.65
	2,000	6.82		6.80	6.85

2013 Crude Oil Hedges (BOPD) ⁽¹⁾

Instrument	Volume	Average ⁽²⁾		Ceiling		
		Price	Floor	Ceiling	Low	High
Q1 Collars	6,000		70.00	109.67	106.50	113.00
	9,000		80.00	105.14	102.25	106.50
	40,000		80.00	108.41	108.00	109.60
Q2 Collars	4,000		75.00	118.25	115.00	121.50
	8,000		80.00	105.63	104.50	106.50
	44,000		80.00	108.43	108.00	109.60
Q3 Collars	4,000		75.00	126.80	120.50	133.10
	16,000		80.00	105.06	104.49	106.50
	36,000		80.00	108.37	108.00	109.60
Q4 Collars	16,000		80.00	103.39	102.25	105.00
	20,000		80.00	120.66	120.00	121.50
	18,000		80.00	126.63	126.00	127.50

2014 Crude Oil Hedges (BOPD) ⁽¹⁾

Instrument	Volume	Average ⁽²⁾		Ceiling		
		Price	Floor	Ceiling	Low	High
1H Collars	46,000		80.00	103.13	101.60	104.50

(1) All crude oil derivative contracts are based on West Texas Intermediate (WTI) NYMEX price basis.

(2) Averages are volume weighted

Capital Structure



(\$MM)	6/30/12
Cash	\$28
Bank credit facility (Borrowing base of \$1.6 billion, matures May 2016)	520
9.750% Sr. Sub Notes due 2016 (Callable March 2013 at 104.875% of par)	411
9.500% Sr. Sub Notes due 2016 (Callable May 2013 at 104.75% of par)	235
8.250% Sr. Sub Notes due 2020 (Callable February 2015 at 104.125% of par)	996
6.375% Sr. Sub Notes due 2021 (Callable August 2016 at 103.188% of par)	400
Other Encore Sr. Sub Notes	4
Genesis pipeline financings / other capital leases	376
Total long-term debt	\$2,942
Equity	5,153
Total capitalization	\$8,095
2Q12 Annualized Adjusted cash flow from operations ⁽¹⁾	\$1,447
Debt to 2Q12 Annualized Adjusted cash flow from operations ⁽¹⁾	2.0x
Debt to total capitalization	36%

(1) A non-GAAP measure, please visit our website for a full reconciliation.

Encore Acquisition was Highly Profitable



Purchase price:	(Billions)
Equity	\$2.8
Debt assumed	1.0
Total value	\$3.8 (1)

Value: (Estimated values at \$96.19/Bbl – 12/31/11 SEC Pricing)	
Proved reserves at 12/31/11	\$1.7 (2)
Value received or anticipated from sold properties	~3.6 (3)
Net cash flow from 3/9/10 to 12/31/11	0.4
Total	~\$5.7
Additional potential:	
EOR potential	(227 MMBOE) (4)

(1) Excludes consolidated ENP debt and minority interest in ENP.

(2) Excludes sold properties, and ENP reserves.

(3) Includes ~\$2 billion of estimated value of Bakken sale.

(4) Includes EOR potential at Bell Creek and CCA.