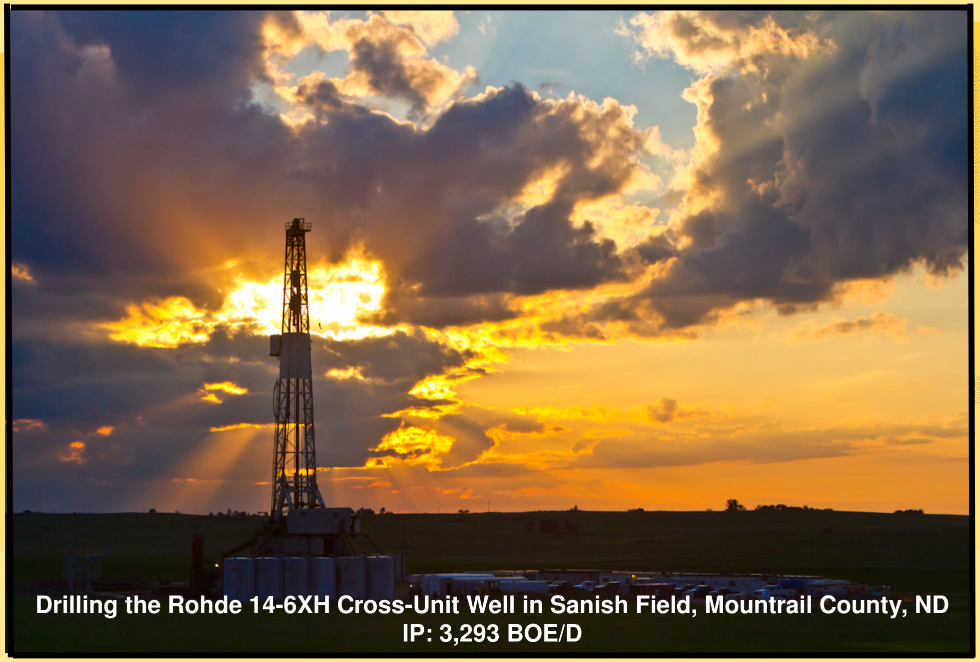
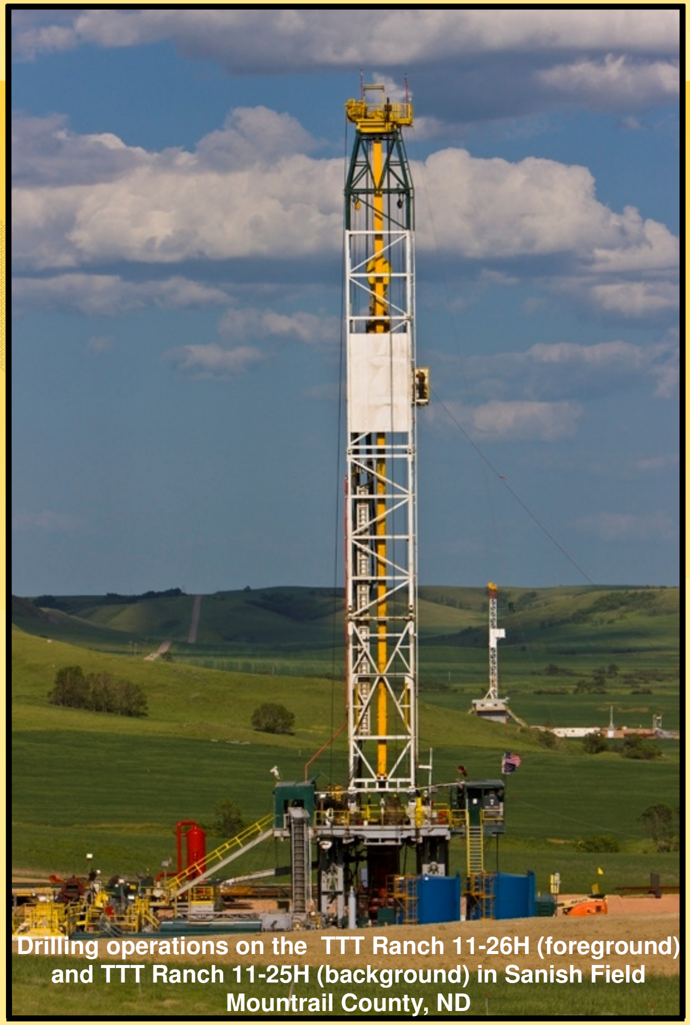
Whiting Petroleum Corporation



Drilling the Rohde 14-6XH Cross-Unit Well in Sanish Field, Mountrail County, ND
IP: 3,293 BOE/D



Drilling operations on the TTT Ranch 11-26H (foreground) and TTT Ranch 11-25H (background) in Sanish Field
Mountrail County, ND

Current Corporate Information
October 2010

Forward-Looking Statement Disclosure, Non-GAAP Measures

This presentation includes forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact included in this presentation are forward-looking statements. These forward looking statements are subject to risks, uncertainties, assumptions and other factors, many of which are beyond the control of the Company. Important factors that could cause actual results to differ materially from those expressed or implied by the forward-looking statements include the Company's business strategy, financial strategy, oil and natural gas prices, production, reserves and resources, impacts from the global recession and tight credit markets, the impacts of hedging on our results of operations, level of success in exploitation, exploration, development and production activities, uncertainty regarding the Company's future operating results and plans, objectives, expectations and intentions and other factors described in the Company's prospectus supplement dated September 20, 2010. In addition, Whiting's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

In this presentation, we refer to Adjusted Net Income and Discretionary Cash Flow, which are non-GAAP measures that the Company believes are helpful in evaluating the performance of its business. A reconciliation of Adjusted Net Income and Discretionary Cash Flow to the relevant GAAP measures can be found at the end of the presentation.

Reserve and Resource Information

Whiting uses in this presentation the terms proved, probable and possible reserves. Proved reserves are reserves which, 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 under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Probable reserves are reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of probable and possible reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by the Company.

Whiting uses in this presentation the term "total resources," which consists of contingent and prospective resources, which SEC rules prohibit in filings of U.S. registrants. Contingent resources are resources that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles. For contingent resources to move into the reserves category, the key conditions, or contingencies, that prevented commercial development must be clarified and removed. Prospective resources are estimated volumes associated with undiscovered accumulations. These represent quantities of petroleum which are estimated to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have not yet been drilled. This class represents a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the accumulations must be further evaluated and an estimate of quantities that would be recoverable under appropriate development projects prepared. Estimates of resources are by nature more uncertain than reserves and accordingly are subject to substantially greater risk of not actually being realized by the Company.

Company Overview

Drilling the Hutchins Stock Association #1096 in North Ward Estes Field, Whiting's EOR project in Winkler County, Texas.

Market Capitalization[1]	*$5.7 B*
Long-term Debt[2]	*$705.3 MM*
Shares Outstanding[3]	*58.5 MM*
Debt/Total Cap[2]	*22.7%*
Proved reserves[4]	*275.0 MMBOE*
% Oil	*81%*
RP ratio[5]	*13.6 years*
Q2 2010 Production	*64.6 MBOE/d*

1 Assumes a $97.47 share price (closing price as of October 1, 2010) on 58,547,487 common shares pro forma for the closing of the convertible preferred exchange offer, which closed on September 17, 2010.

2 Pro forma as of June 30, 2010 for redemption of Whiting's $150 million 7¼% Senior Subordinated Notes due 2012 and its $220 million 7¼% Senior Subordinated Notes due 2013, the convertible preferred exchange offer and the issuance of $350 million 6½% Senior Subordinated Notes due 2018, which closed on September 24, 2010. Please refer to Slide #51 for details.

3 Pro forma as of June 30, 2010 for convertible preferred exchange offer.

4 Whiting reserves at December 31, 2009 based on independent engineering.

5 R/P ratio based on year-end 2009 proved reserves and 2009 production.

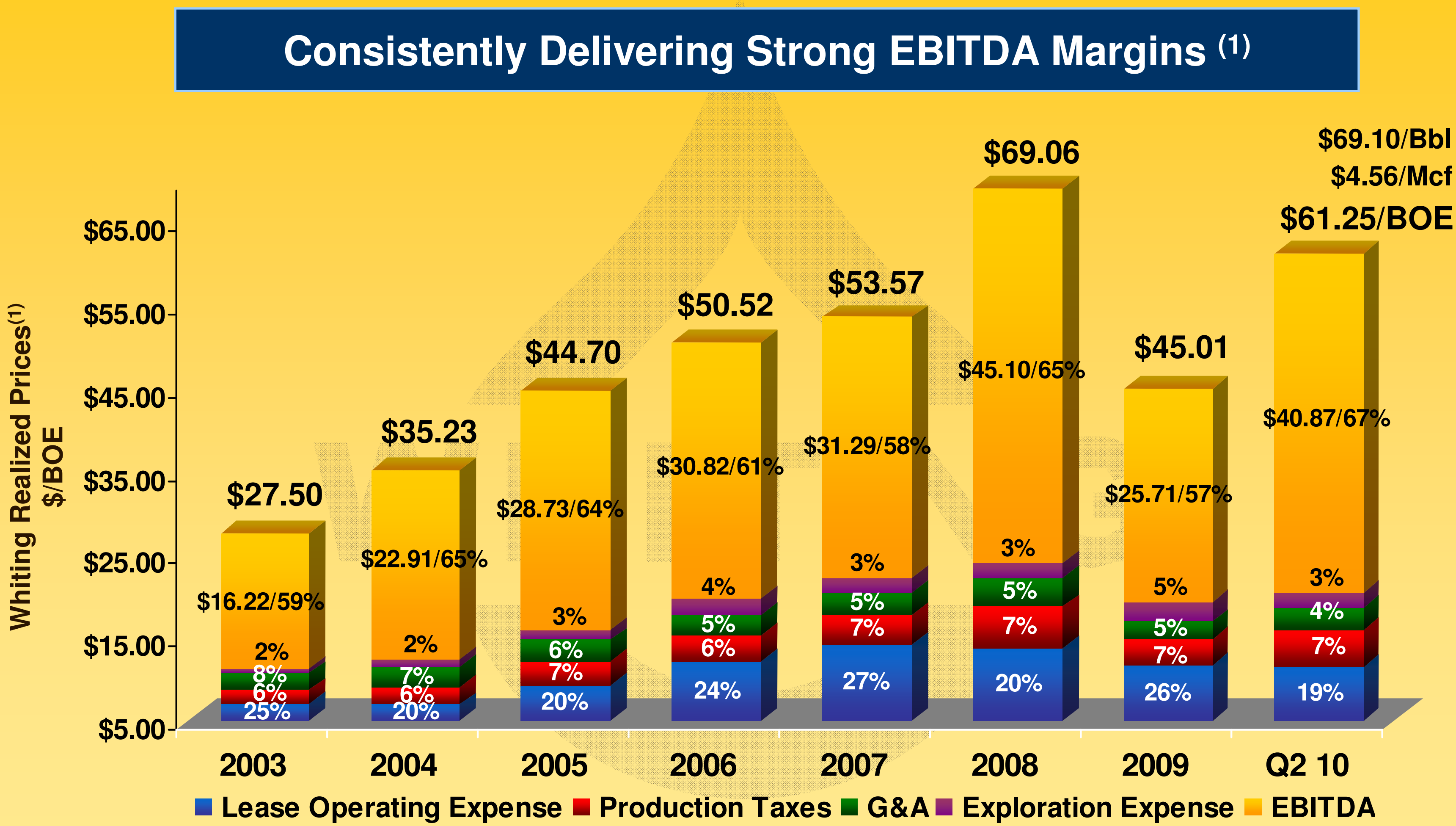
Adjusted Net Income and Discretionary Cash Flow for the Three Months Ended June 30, 2010 and 2009 (1)(2)

	Three Months Ended	
	6/30/10	6/30/09
(In millions, except per share data)		
Net Income (Loss)	$ 119.9	($ 93.2)
Adjusted Net Income (Loss)	$ 72.2	($ 0.6)
Adjusted Earnings (Loss) Per Basic Share	$ 1.42	($ 0.01)
Adjusted Earnings (Loss) Per Diluted Share	$ 1.31	($ 0.01)
Discretionary Cash Flow	$ 228.2	$ 109.7

(1) Please refer to slide #55 for a Reconciliation of Net Income Available to Common Shareholders to Adjusted Net Income Available to Common Shareholders.

(2) Please refer to slide #56 for a Reconciliation of Net Cash Provided by Operating Activities to Discretionary Cash Flow.

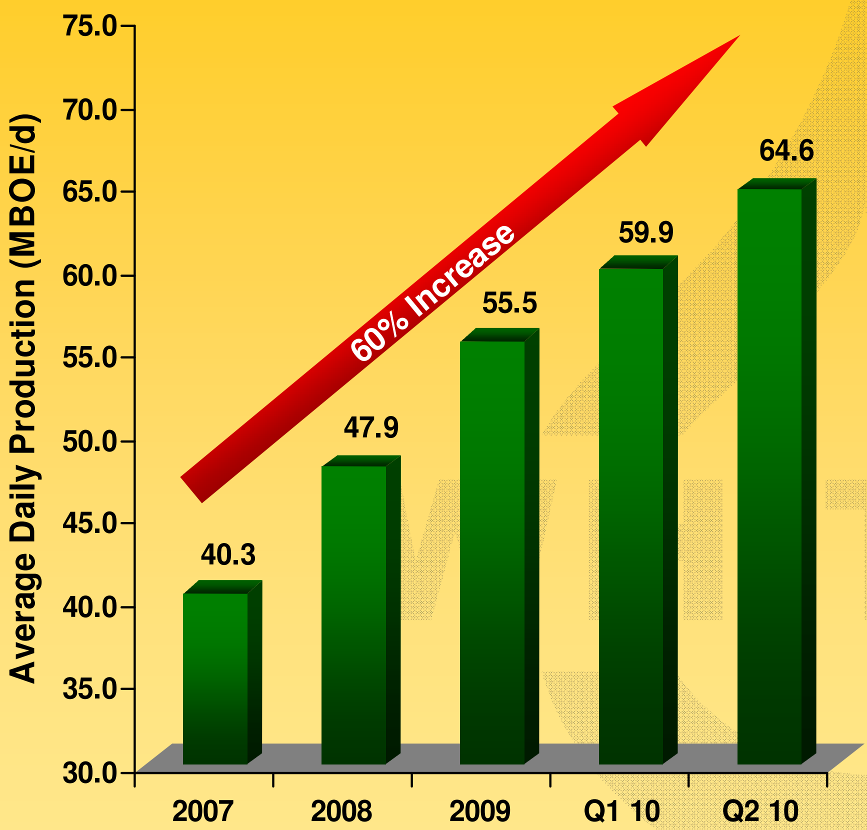
Consistently Strong Margins



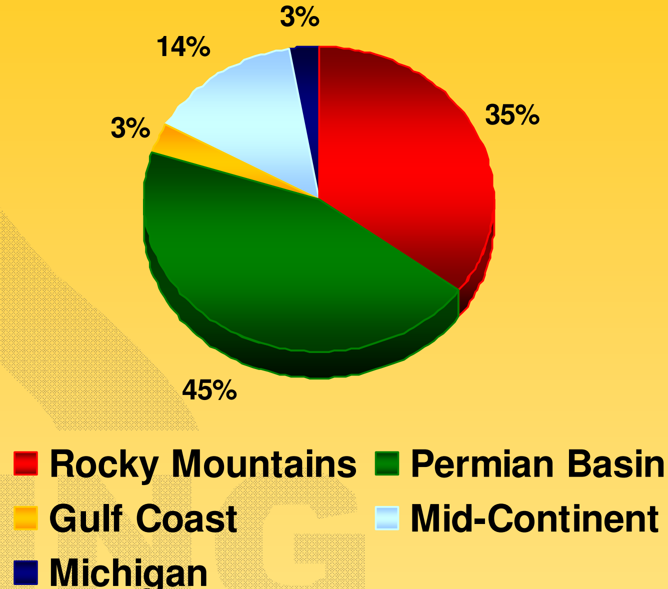
(1) Includes hedging adjustments.

Platform for Continued Growth

Average Daily Production



Proved Reserves (12/31/2009)

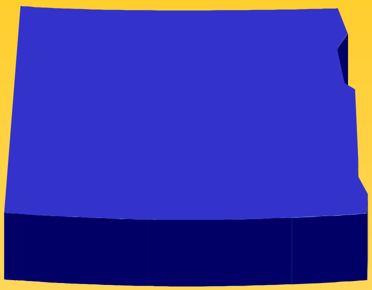


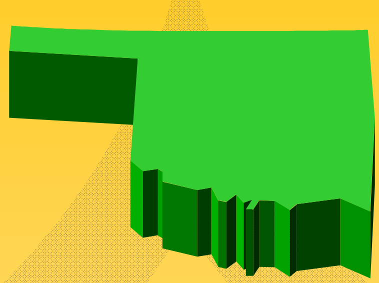
- 275.0 MMBOE (12/31/2009)
- 81% Oil / 19% Natural Gas
- 64% Developed / 36% Undeveloped
- 917,517 Net Acres (59% Developed)
- $2.9 Billion PV10% (pre-tax)

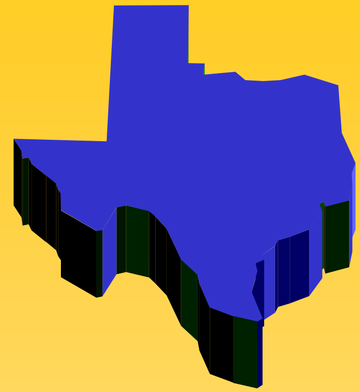
At December 31, 2009, Whiting Had a 13.6 Year R/P Ratio [1] Supported by a Strong Portfolio of Development Opportunities

(1) R/P ratio based on year-end 2009 proved reserves and 2009 production.

Whiting a Top Oil Producer in Three States







NORTH DAKOTA [1]

#2

1,300,000 Barrels Per Month (August 2010)

OKLAHOMA [2]

#5

Total Barrels: 1,469,014

TEXAS [3]

#16

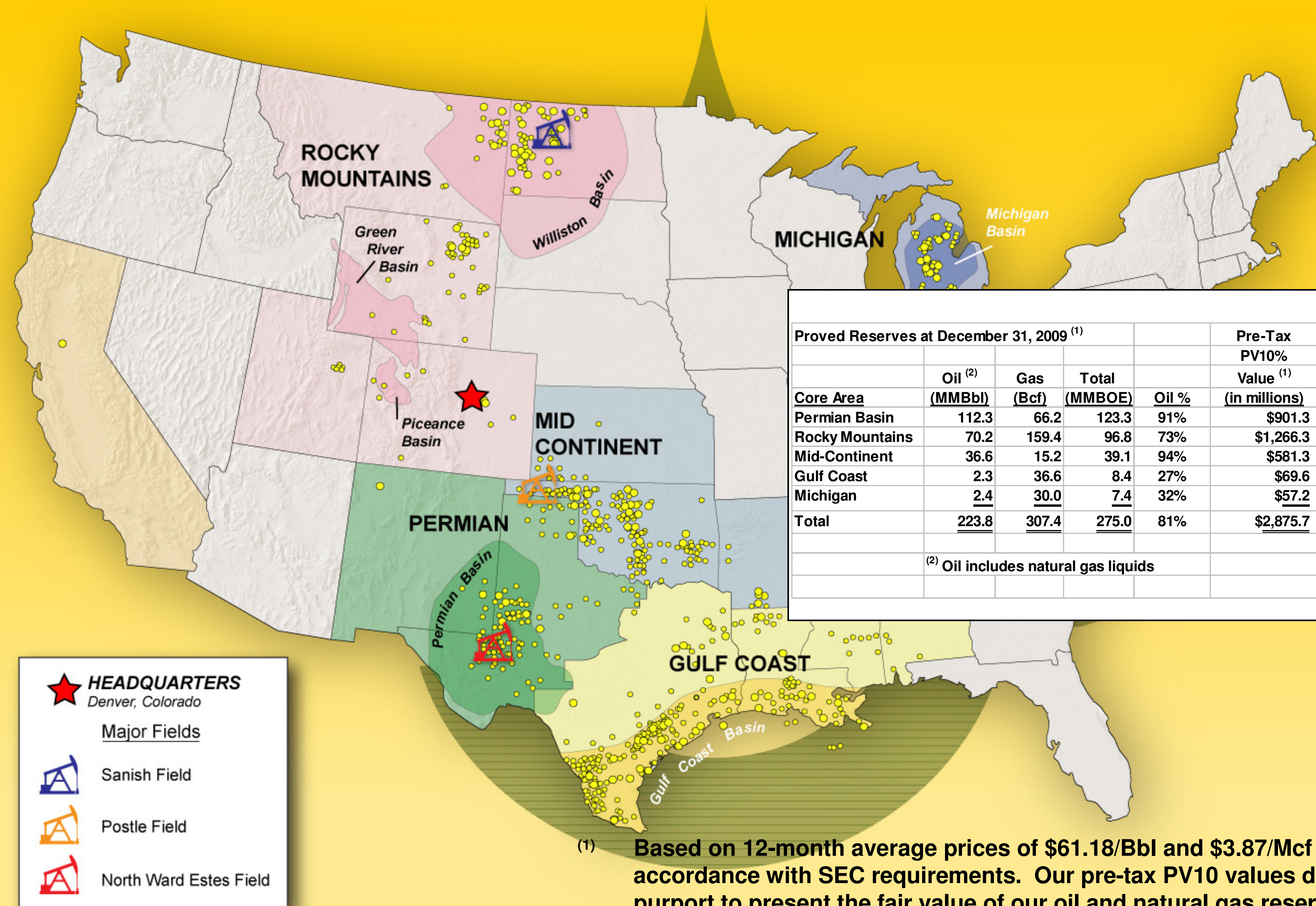
Total Barrels: 3,571,309

(1) Whiting was the second largest producer according to the North Dakota Industrial Commission for the month ended January 31, 2010, in which Whiting's gross operated production was 807,600 barrels of oil per month. As of August 2010, Whiting's gross operated production was 1.3 million barrels of oil per month, which is an annualized rate of 15.6 million barrels per year.

(2) According to the Oklahoma Corporation Commission for the year 2008.

(3) According to the Railroad Commission of Texas for the year 2009.

Map of Operations



Proved Reserves at December 31, 2009 (1)					Pre-Tax PV10% Value (1)	Q2 2010 Average Daily Net Production
Core Area	Oil (2) (MMBbl)	Gas (Bcf)	Total (MMBOE)	Oil %	(in millions)	(MBOE/d)
Permian Basin	112.3	66.2	123.3	91%	$901.3	12.0
Rocky Mountains	70.2	159.4	96.8	73%	$1,266.3	37.0
Mid-Continent	36.6	15.2	39.1	94%	$581.3	10.0
Gulf Coast	2.3	36.6	8.4	27%	$69.6	2.8
Michigan	2.4	30.0	7.4	32%	$57.2	2.8
Total	223.8	307.4	275.0	81%	$2,875.7	64.6

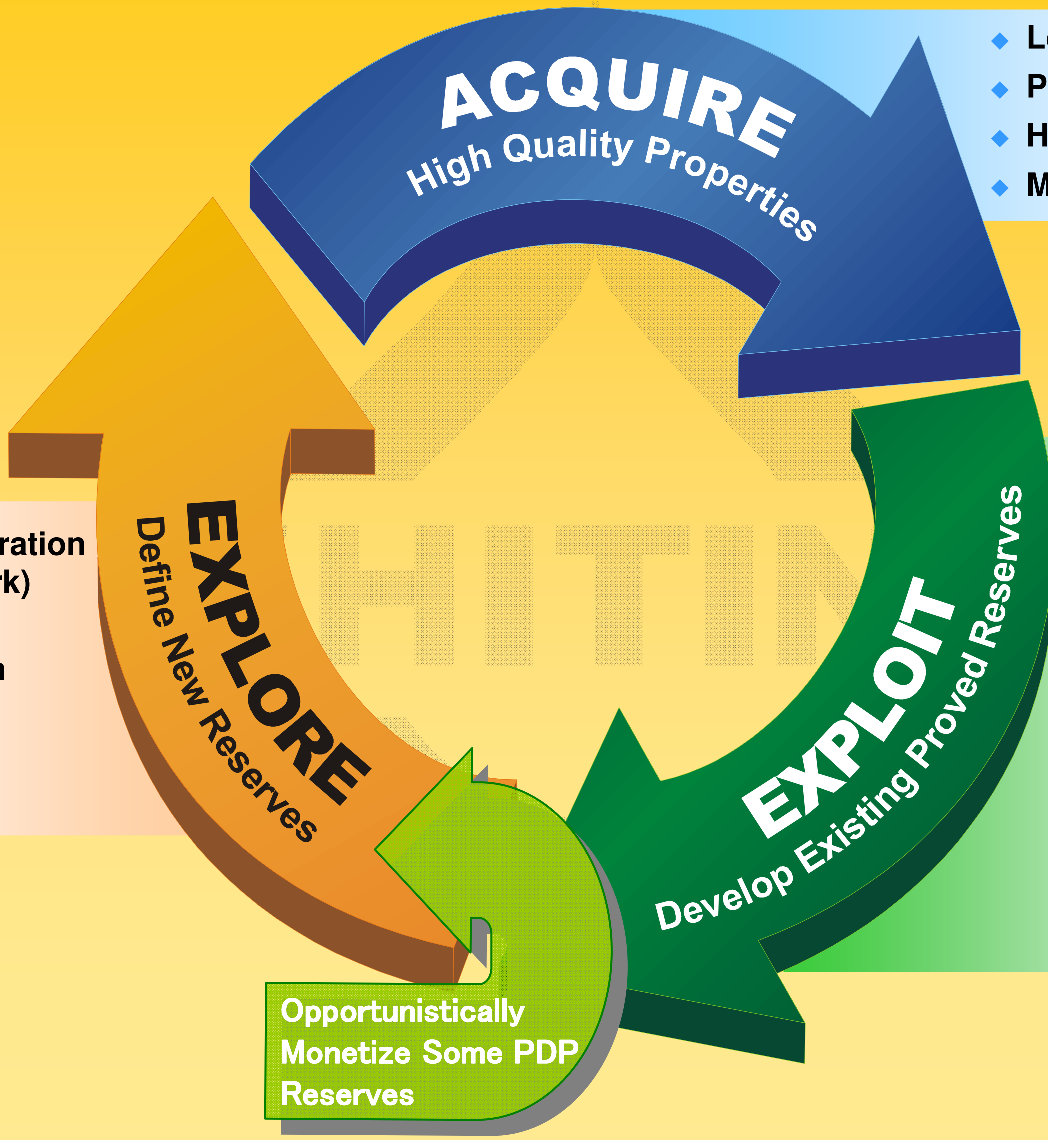
(2) Oil includes natural gas liquids

(1) Based on 12-month average prices of $61.18/Bbl and $3.87/Mcf in accordance with SEC requirements. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.

Our Formula for Success

- Long-lived properties
- Predictable performance
- High PDP content
- Multi-zone potential

- New Rockies exploration areas (Lewis & Clark)
- Other horizontal oil prospects (Permian Basin)



- Permian Basin – North Ward Estes field
- Anadarko Basin – Postle field
- Williston Basin – Bakken Sanish and Parshall field areas
- Piceance Basin - Boies Ranch / Jimmy Gulch prospect areas
- Uintah Basin – Flat Rock Field

Whiting Total Reserves and Resources at Dec. 31, 2009

	MMBO	MMBNGL	Oil & NGL MMBO	BCF	MMBOE	% of MMBOE
PDP	104	12	116	157	142	19.5%
PBP	2	1	3	13	5	0.7%
PNP	23	3	26	8	27	3.7%
PUD	64	15	79	129	101	13.8%
Total Proved (1) (2)	193	31	224	307	275	
Total Probable (1) (3)	45	13	58	182	89	12.2%
Total Possible (1) (4)	135	32	167	185	198	27.1%
Total 3P Reserves	373	76	449	674	562	
Resource Potential (5)	93	19	112	337	168	23.0%
Total Reserve and Resource Potential	466	95	561	1,011	730	100.0%

(1) Proved, Probable and Possible Reserves based on independent engineering by Cawley Gillespie & Associates, Inc. at December 31, 2009. Based on 12-month average prices of $61.18/Bbl and $3.87/Mcf in accordance with SEC requirements. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(2) Future capital expenditures for total Proved Reserves are estimated at $1,406M.

(3) Future capital expenditures for total Probable Reserves are estimated at $806M.

(4) Future capital expenditures for total Possible Reserves are estimated at $1,439M.

(5) Whiting has internally estimated its unrisked Total Resource potential using prices of $75/Bbl and $6.00/Mcf held flat. Future capital expenditures associated with Resources are estimated at $2,195M. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

Major Fields with Probable and Possible Reserves at December 31, 2009 (1) (2)

Region	Field	MMBOE	Capex MM$	$ Per BOE
Permian	North Ward Estes	124	647	5.22
(Additional phases and larger CO_2 slug sizes)				
Rockies	Sanish	63	586	9.30
(65 flank and cross-unit Bakken wells plus 140 Three Forks wells)				
Rockies	Sulphur Creek	28	328	11.71
(193 20- and 10-acre wells)				
Rockies	Parshall	9	98	10.89
(93 Three Forks wells)				
	Total (78% of 287 MMBOE)	224	1,659	7.41

(1) **Based on independent engineering by Cawley Gillespie & Associates, Inc. at December 31, 2009. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.**

(2) **Based on 12-month average prices of $61.18/Bbl and $3.87/Mcf in accordance with SEC requirements.**

Whiting Total Resource Potential at Dec. 31, 2009 (1)(2)(3)

Using Prices of $75.00/Bbl and $6.00/Mcf Held Flat

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	MMBO	MMBNGL	Oil & NGL MMBO	Nat. Gas BCF	MMBOE	PV10, MM$
Lewis & Clark – ND **(3 Forks Expl. Drlg.)**	58	5	63	24	66	$ 828
Sanish Field – ND **(Increase 3 Forks Drilling Density to 3 Wells per 1,280-acre Unit from 2)**	14	2	16	8	17	$ 185
Other Williston Basin **(Red River and 3 Forks Expl. Drlg.)**	11	0	11	2	12	$ 193
Sulphur Creek – CO **(Higher NYMEX Gas Price of Approx. $6.00/Mcf)**	1	12	13	161	40	$ 90
Other Area – WY, UT & MI **(Expl. Drlg. in Niobrara Shale in WY, Cane Creek in UT & PDC in MI)**	9	0	9	142	33	$ 206
Total Resource Potential	93	19	112	337	168	$ 1,502

(1) Whiting has internally estimated its unrisked Total Resource potential. PV10 values were based on NYMEX price assumptions of $75.00/Bbl and $6.00/Mcf. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.

(2) Future capital expenditures for Total Resources are estimated at $2,195M.

(3) Estimated future capital expenditures associated with these areas are as follows: Lewis & Clark $981MM, Sanish $234MM, Other Williston Basin $165MM, Sulphur Creek $419MM, Other WY, UT, MI $396MM.

Whiting Total Reserves & Resources at Dec. 31, 2009

with Breakout of % Bakken and EOR

	MMBOE	BAK & 3FKS (MMBOE)	BAK & 3FKS %	POSTLE & N WARD (MMBOE)	POSTLE & N WARD %
PDP	142	25	18%	57	40%
PBP	5	0	0%	0	0%
PNP	27	0	0%	22	81%
PUD	101	19	19%	49	49%
Total Proved [(1)]	275	44	16%	128	47%
Total Probable [(1)]	89	3	3%	32	36%
Total Possible [(1)]	198	70	35%	94	47%
Total 3P Reserves	562	117	21%	254	45%
Resource Potential [(2)]					
LEWIS & CLARK – ND	66	66	100%		
SANISH – ND	17	17	100%		
OTHER WILLISTON BASIN	12	4	33%		
SULPHUR CREEK – CO	40	0	0%		
OTHER AREAS - WY, UT & MI	33	0	0%		
Total Resource Potential	168	87	52%		
Total 3P Reserve and Resource Potential	730	204	28%	254	35%

(1) The Proved, Probable and Possible reserve estimates shown are based on independent engineering by Cawley, Gillespie & Associates, Inc. at December 31, 2009 using SEC NYMEX prices of $61.18/Bbl and $3.87/Mcf. The PV10 values shown in other slides, however, were based on estimated reserves calculated using NYMEX price assumptions of $75.00/Bbl and $6.00/Mcf. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(2) Whiting has internally estimated its "Total Resource" potential at NYMEX prices of $75/Bbl and $6.00/Mcf. Please see Slide #2 for the definition of "Total Resource." All volumes shown are unrisked.

Whiting Pre-Tax PV10 Values at Dec. 31, 2009 (1)

Using $75.00/Bbl and $6.00/Mcf Held Flat – Excludes Resource Potential (2)

	MMBO	MMBNGL	Oil & NGL MMBO	Nat. Gas BCF	MMBOE	PV10, MM$
PDP	104	12	116	157	142	$ 2,755
PBP	2	1	3	13	5	$ 71
PNP	23	3	26	8	27	$ 464
PUD	64	15	79	129	101	$ 1,125
Total Proved	193	31	224	307	275	$ 4,415
Total Probable	45	13	58	182	89	$ 895
Total Possible	135	32	167	185	198	$ 1,565
Total 3P Reserves	373	76	449	674	562	

(1) Reserve estimates shown are based on independent engineering by Cawley, Gillespie & Associates, Inc. at December 31, 2009 using SEC NYMEX price assumptions of $61.18/Bbl and $3.87/Mcf. The PV10 values, however, were based on estimated reserves calculated using NYMEX price assumptions of $75.00/Bbl and $6.00/Mcf. The new reserve volumes estimated using the higher price assumptions were 293 MMBOE for proved, 99 MMBOE for Probable, 204 MMBOE for Possible and 597 MMBOE for Total 3P Reserves. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.

(2) Whiting has internally estimated its "Total Resource" potential. At NYMEX prices of $75.00/Bbl and $6.00/Mcf, Whiting estimates its Total Resource at 168 MMBOE with a PV10% value of $1.5 billion. This value has not been included above. Please see slide #2 for the definition of "Total Resource." All volumes shown are unrisked.

Finding Costs

(in Thousands)

	2004	2005	2006	2007	2008	2009	Six-Year Total/Avg. (2004 – 2009)
Proved Acquisitions	$ 525,563	$ 906,208	$ 29,778	$ 8,128	$ 294,056	$ 78,800	$ 1,842,533
Unproved Acquisitions	$ 4,401	$ 16,124	$ 38,628	$ 13,598	$ 98,841	$ 12,872	$ 184,464
Development Cost	$ 74,476	$ 215,162	$ 408,828	$ 506,057	$ 914,616	$ 436,721	$ 2,555,860
Exploration Cost	$ 9,739	$ 22,532	$ 81,877	$ 56,741	$ 42,621	$ 50,970	$ 264,480
Change in Future Dvlp. Cost	$ 150,538	$ 692,229	$ 267,685	$ 10,048	$ (204,633)	$ 423,541	$ 1,339,408
Total	$ 764,717	$ 1,852,255	$ 826,796	$ 594,572	$1,145,501	$ 1,002,904	$ 6,186,745
Acquisition Reserves							
Acquisition – Oil (MBbls)	52,288	115,737	670	691	513	3,177	173,076
Acquisition – Gas (MMcf)	114,715	101,082	4,009	-	90,329	4,155	314,290
Total Acquisition (MBOE)	71,407	132,584	1,338	691	15,568	3,870	225,458
Development Reserves							
Development – Oil (MBbls)	5,175	1,956	4,125	10,973	20,395	25,115	67,739
Development – Gas (MMcf)	29,133	21,068	19,362	40,936	57,093	41,969	209,561
Total Development (MBOE)	10,031	5,467	7,352	17,796	29,911	32,109	102,666
Revisions							
Reserve Revisions – Oil (MBbls)	(853)	950	2,053	392	(20,851)	33,566	15,257
Reserve Revisions – Gas (MMcf)	(9,862)	(45,322)	(57,780)	8,079	(74,689)	(62,618)	(242,192)
Total Reserve Revisions (MBOE)	(2,497)	(6,604)	(7,577)	1,739	(33,299)	23,130	(25,108)
Cost Per BOE to Acquire	$ 7.36	$ 6.83	$ 22.25	$ 11.76	$ 18.89	$ 20.36	$ 8.17
Cost Per BOE to Develop	$ 31.75	$ -	$ -	$ 30.02	$ -	$ 16.73	$ 56.01
All-In Finding Cost Per BOE	$ 9.69	$ 14.09	$ 742.74	$ 29.40	$ 94.05	$ 16.97	$ 20.42

Unrisked Probable and Possible Reserves – BOE	286,596
Probable and Possible Cap-Ex	$ 2,244,649
All-In Rate with Future Dvlp. Cost and Prob. & Poss.	$ 14.30

Key Development Areas for 2010
($ in millions)

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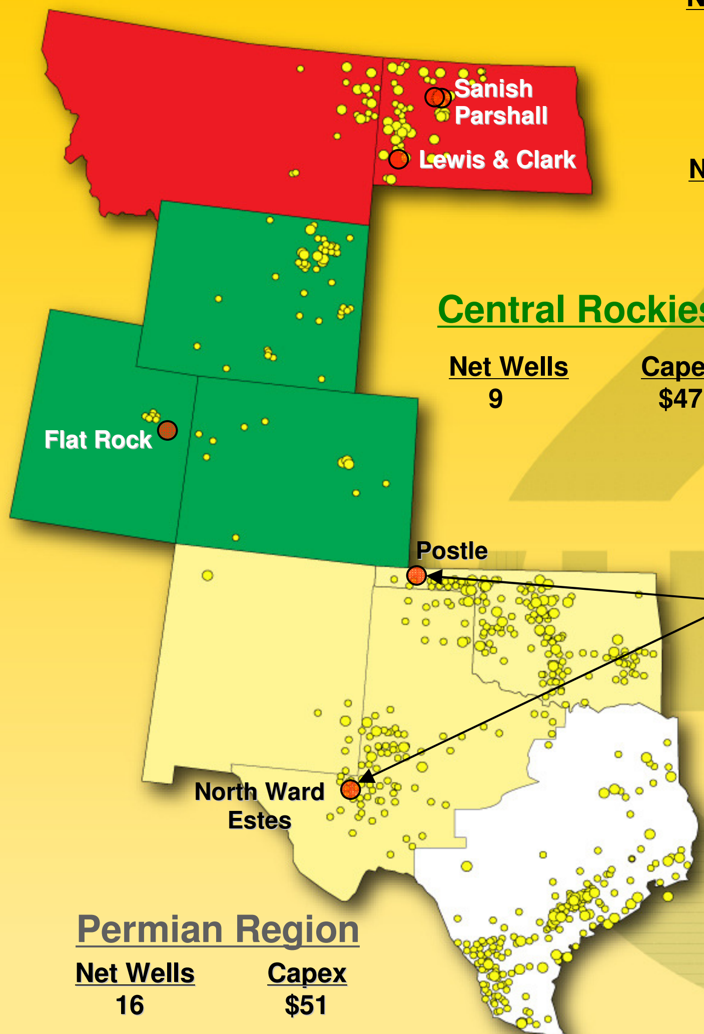


Northern Rockies

Sanish Field

Net Wells	Capex
52	$273

Lewis & Clark

Net Wells	Capex
10	$77

Central Rockies

Net Wells	Capex
9	$47

EOR Projects

Net Wells	Capex
18	$230

Gulf Coast

Net Wells	Capex
7	$29

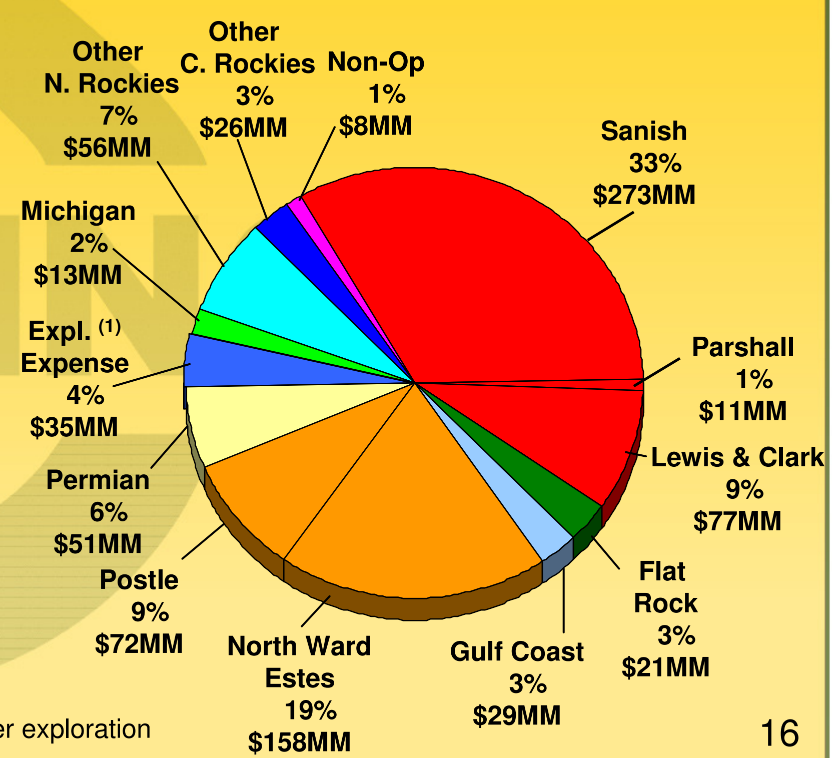
Permian Region

Net Wells	Capex
16	$51

Existing Properties

2010 Capital Projects

2010 Exploration & Development Budget $830 MM



(1) Comprised primarily of exploration salaries, lease delay rentals, seismic and other exploration and development.

2010 Exploration and Development Budget
Estimated Gross and Net Wells in 2010

	EST. 2010 CAPEX (In MM)	PLANNED WELLS Gross	Net
NORTHERN ROCKIES			
Sanish Field	$ 273	98	52
Parshall Field	$ 11	15	3
Lewis & Clark Area	$ 77	13	10
Other Northern Rockies	$ 56	33	9
SUBTOTAL	$ 417	159	74
EOR PROJECTS			
North Ward Estes (1)	$ 158	--	--
Postle (1)	$ 72	24	18
SUBTOTAL	$ 230	24	18
PERMIAN BASIN			
Various	$ 51	20	16
CENTRAL ROCKIES			
Flat Rock Field	$ 21	5	5
Other Central Rockies	$ 26	5	4
SUBTOTAL	$ 47	10	9
GULF COAST			
Various	$ 29	15	7
MICHIGAN			
PDC Expl. & Dvlp.	$ 13	2	2
OTHER, NON-OPERATED	$ 8	--	--
EXPL. EXPENSE (2)	$ 35	--	--
GRAND TOTAL	$ 830	230	126

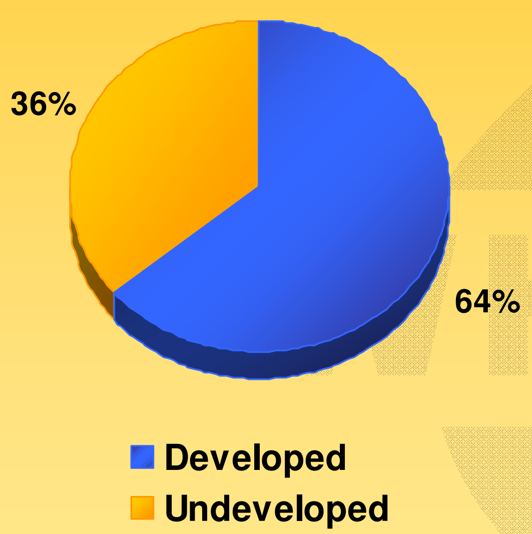
(1) 2010 planned capital expenditures at our CO_2 projects include approximately $52 million for purchased CO_2 at North Ward Estes and $12 million for Postle CO_2 purchases.

(2) Comprised primarily of exploration salaries, lease delay rentals and seismic and other development.

Reserve & Production Profiles

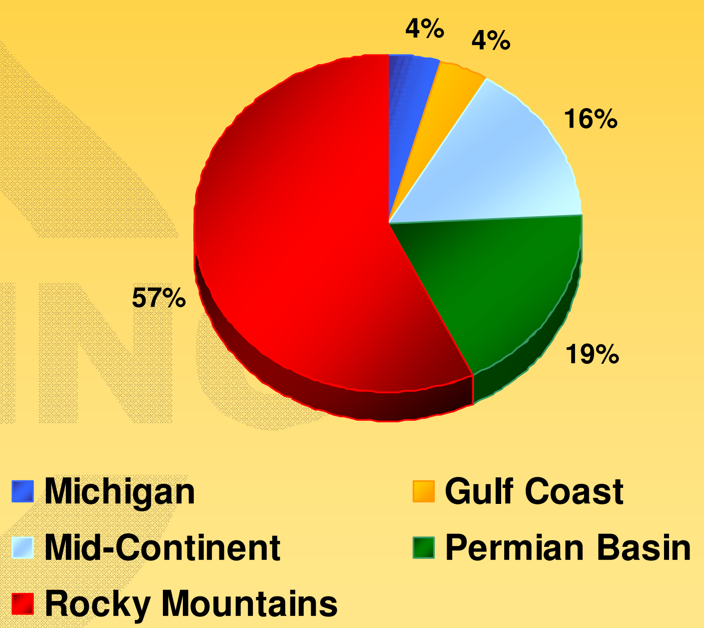
Proved Reserves

As of Dec. 31, 2009
275.0 MMBOE



Avg. Production By Core Area

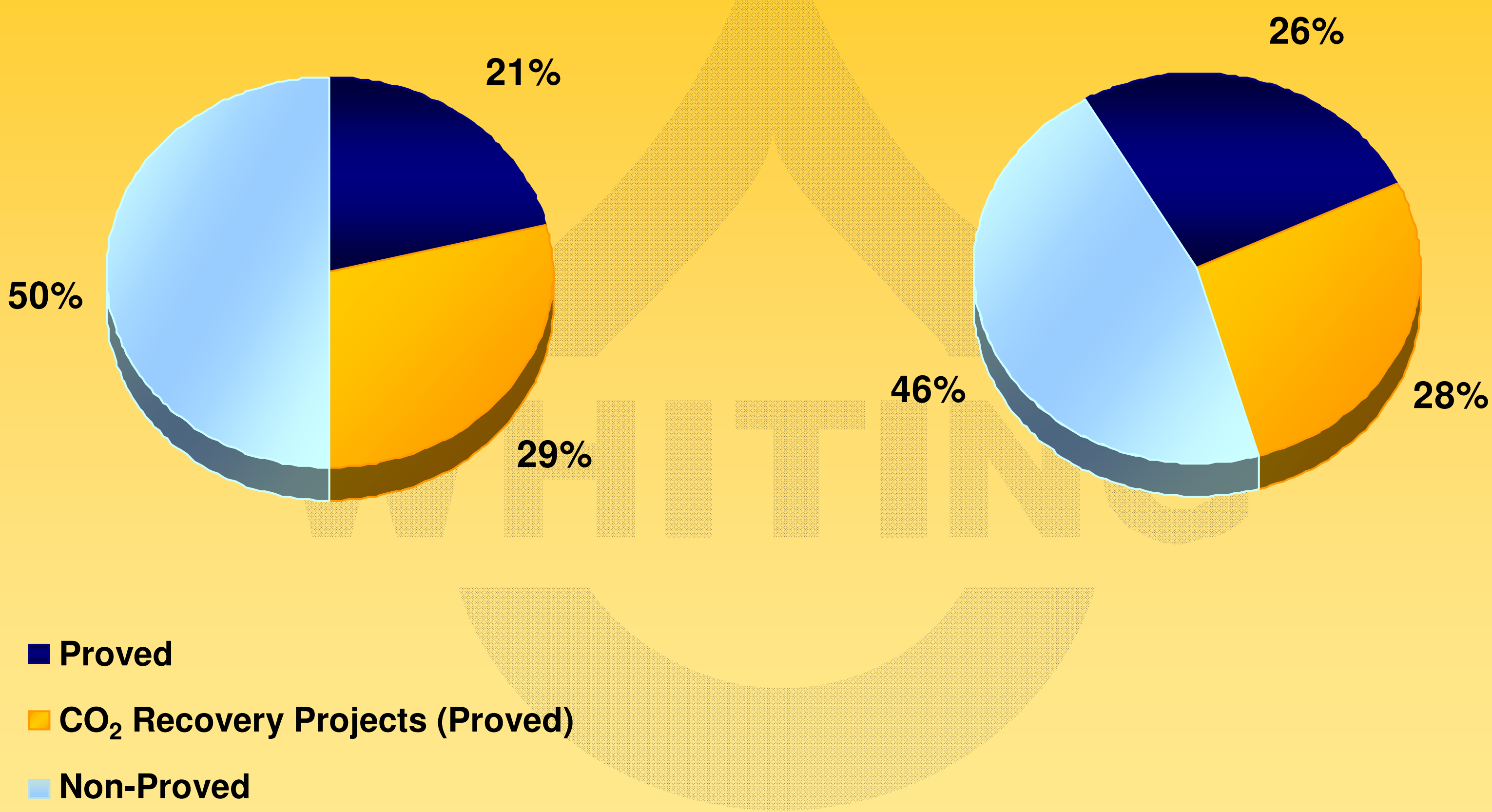
Q2 2010
64.6 MBOE/d



Based on 2009 Production, Whiting Has a 13.6 Year R/P Ratio

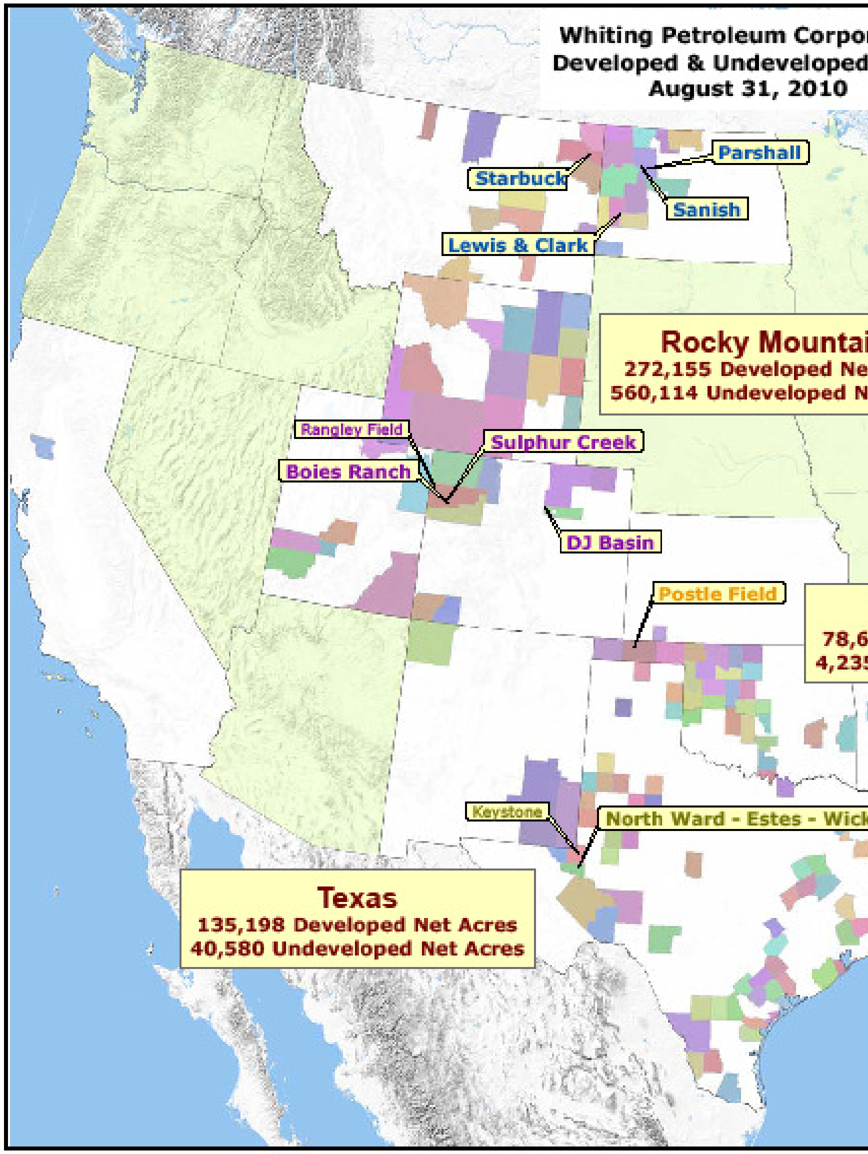
2009 vs. 2010 Exploration & Development Expenditures By Reserve Category

2009 – $480 MM Actual [1]	2010 – $830 MM Budget



[1] This amount was not reduced by $60.5 million of 2009 development costs that Whiting incurred prior to the closing of the Sanish field transaction and were reimbursed to Whiting in the Sanish field transaction.

Whiting Developed & Undeveloped Acreage by Core Area



Company Totals

Gross	Net	
1,110,289	554,121	Developed Acres
1,030,134	604,310	Undeveloped Acres
2,140,423	1,158,431	Total

Whiting Net Acres in Bakken/Three Forks Hydrocarbon System (1)

Prospect Area	Formation	Gross Acres	Net Acres	Net Undeveloped Bakken/Three Forks Acreage
North Dakota				
Lewis & Clark	Bakken & Three Forks	340,241	225,685	222,428
Sanish	Bakken & Three Forks	112,427	67,893	35,304
Parshall	Bakken & Three Forks	73,242	18,188	1,457
Hidden Bench/ Tarpon	Bakken & Three Forks	42,969	24,378	24,378
Cassandra	Bakken & Three Forks	26,286	14,459	12,466
Big Island	Bakken	63,879	49,133	49,133
Other ND	Bakken & Three Forks	60,124	29,170	29,170
Montana				
Starbuck	Bakken & Three Forks	111,966	90,174	90,174
Other Montana	Bakken & Three Forks	37,839	13,186	13,186
Total		868,973	532,266 (2)	477,696

(1) As of September 30, 2010.

(2) Whiting's total acreage cost in the 532,266 net acres is approximately $89.4 million, or $168 per net acre, based on current book value.

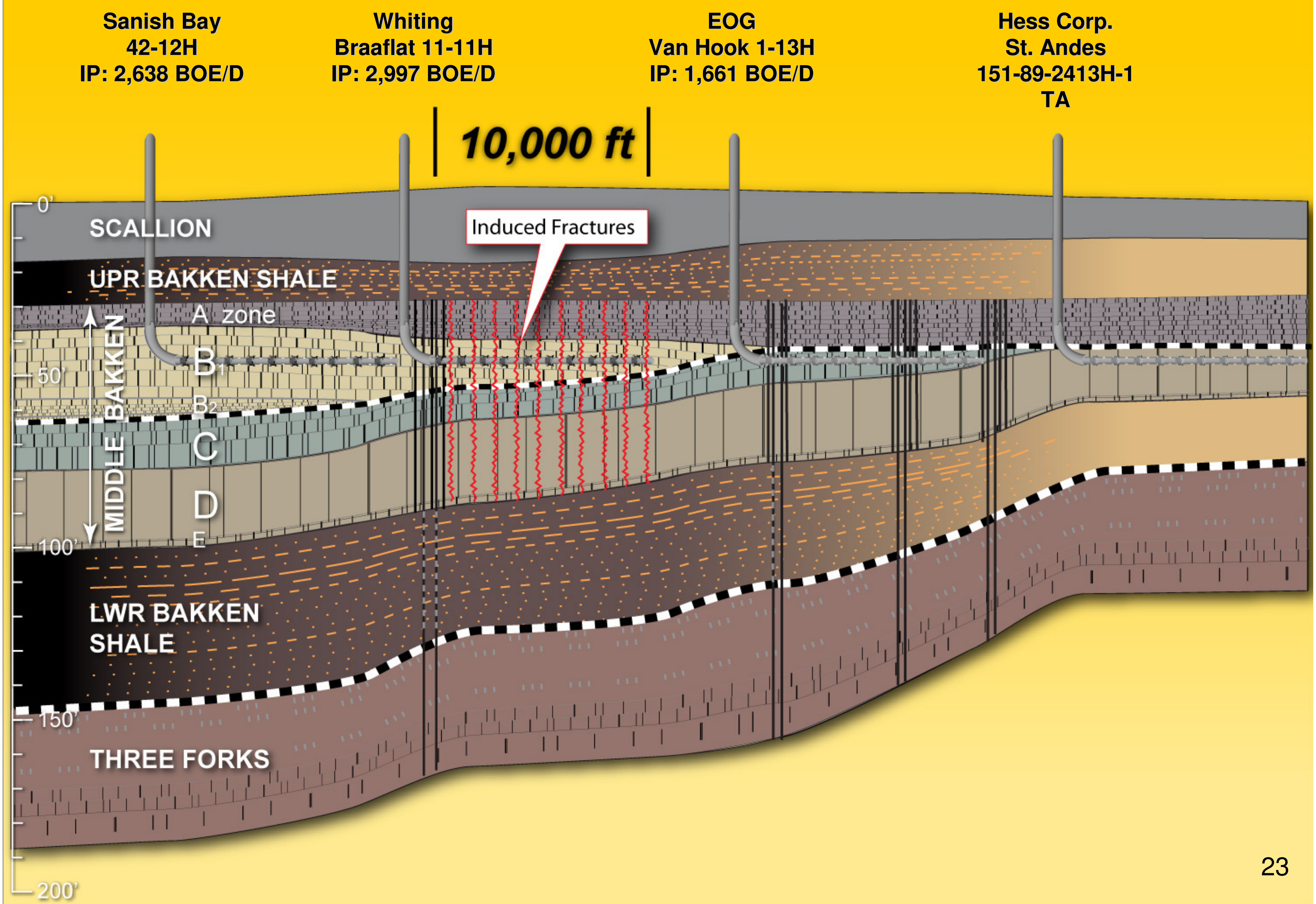
Whiting Williston Basin Bakken Activity

Foreground: the Smith 11-7H was completed on 8/2/08, flowing 2,421 BOED.

Background: Drilling the Kannianan 11-5H, which flowed 1,998 BOED at completion on 9/3/09.

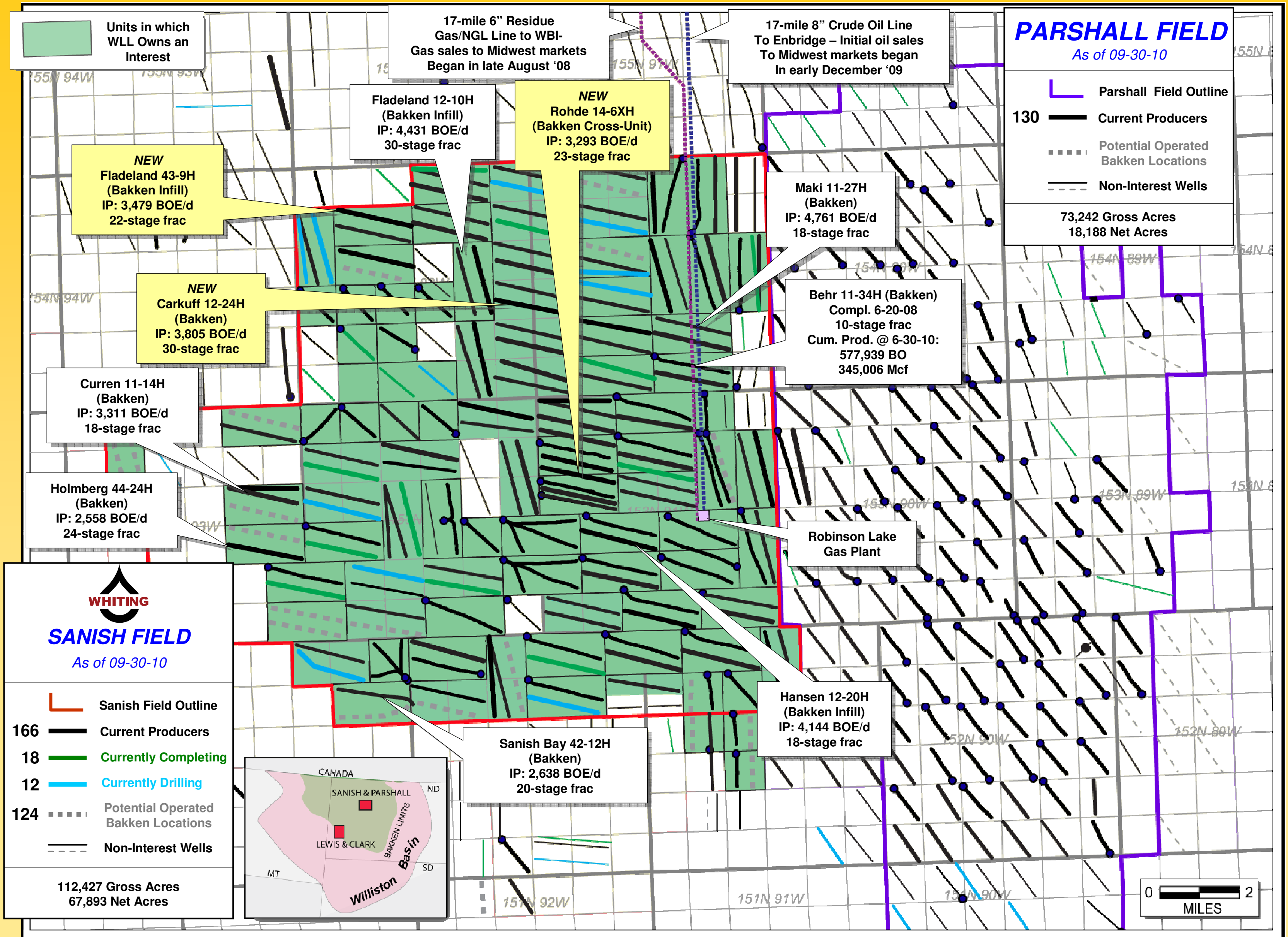
- Basin-wide stratigraphic trap in shale and dolomitic siltstone
- 185,669 gross; 86,081 net acres in Sanish and Parshall fields
- Average EUR 850 MBOE/well, average CWC of approximately $5.0MM
- Whiting plans to complete 90 operated wells and participate in 8 non-operated wells for a total of 98 gross (52 net) wells in Sanish field in 2010
- Whiting plans to participate in 12 gross (2 net) wells in the non-operated Parshall field in 2010

Middle Bakken Induced Fractures



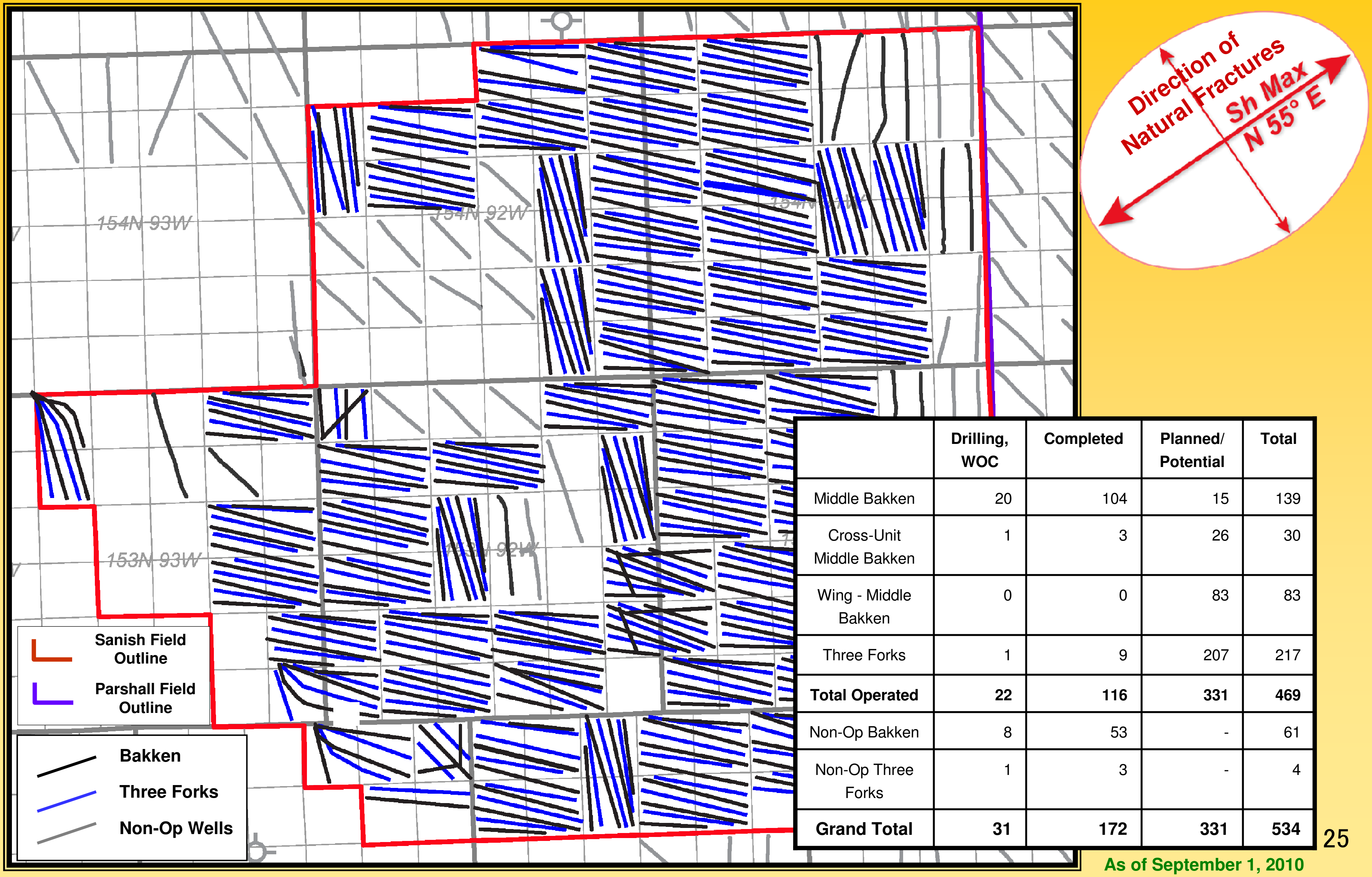
Sanish and Parshall Fields -
Recent and Notable Wells

WHITING



Fully Developed Bakken and Three Forks Horizontal Wells in Sanish Field Area

WHITING



	Drilling, WOC	Completed	Planned/ Potential	Total
Middle Bakken	20	104	15	139
Cross-Unit Middle Bakken	1	3	26	30
Wing - Middle Bakken	0	0	83	83
Three Forks	1	9	207	217
Total Operated	**22**	**116**	**331**	**469**
Non-Op Bakken	8	53	-	61
Non-Op Three Forks	1	3	-	4
Grand Total	**31**	**172**	**331**	**534**

As of September 1, 2010

30-, 60- and 90-day Average Production Rates for Whiting Operated Bakken Wells in Sanish Field

2010 Wells	WI	NRI	Test Date	IP (BOE/d) 24-hr. Test	Average 1st 30 Days (BOE/d)	Average 1st 60 Days (BOE/d)	Average 1st 90 Days (BOE/d)
1) Ogden 12-3H (1)	57%	47%	08/28/10	2,137			
2) Rohde 14-6XH	61%	49%	08/25/10	3,293			
3) Miller 43-10H (1)	48%	39%	08/23/10	1,669			
4) Hagey 12-13H (1)	41%	33%	08/20/10	2,322			
5) Littlefield 21-12H	87%	71%	08/13/10	2,788			
6) Fladeland 43-9H	30%	24%	08/10/10	3,479			
7) Carkuff 12-24H	38%	31%	08/07/10	3,805			
8) Oppenboen 12-5H	73%	59%	07/19/10	1,875	649		
9) Fladeland 12-10H	70%	56%	07/17/10	4,431	1,316		
10) Kannianen 43-31H	46%	38%	07/09/10	1,910	670		
11) Peterson 13-4H	99%	81%	07/07/10	1,694	713		
12) Moore 14-7XH	89%	72%	07/01/10	1,611	701		
13) Lahti 24-22H	53%	43%	06/19/10	2,058	968	953	
14) Hansen 12-20H	99%	80%	06/18/10	4,144	1,195	982	
15) Iverson 21-14H	47%	39%	06/15/10	2,551	1,241	1,074	
16) Littlefield 12-34H	54%	44%	05/28/10	1,942	1,262	1,139	1,014
17) Lacey 12-1H	86%	70%	05/28/10	3,445	1,245	1,007	867
18) Fladeland 21-12H	31%	26%	05/25/10	2,690	1,251	1,109	988
19) Fladeland 44-9H	30%	25%	05/16/10	2,301	841	684	618
20) Jorgenson 12-27H	76%	62%	05/13/10	2,893	1,434	1,276	1,272

(1) Fracture stimulated in 22 stages using sliding sleeves. Eight additional stages using the “plug and perf” method will be performed at a later date.

(Continued) 30-, 60- and 90-day Average Production Rates for Whiting Operated Bakken Wells in Sanish Field

2010 Wells	WI	NRI	Test Date	IP (BOE/d) 24-hr. Test	Average 1st 30 Days (BOE/d)	Average 1st 60 Days (BOE/d)	Average 1st 90 Days (BOE/d)
21) Niemitalo 12-35H	80%	65%	05/09/10	2,860	1,251	1,125	1,029
22) Olson Federal 42-8H	84%	70%	05/02/10	1,912	922	893	861
23) Curren 11-14H	21%	17%	04/24/10	3,311	1,016	774	707
24) TTT Ranch 12-25H	40%	32%	04/21/10	2,513	1,230	1,157	1,017
25) Rohde 43-1H	30%	25%	04/18/10	2,949	1,049	1,020	950
26) Holmberg 44-24H	36%	27%	04/13/10	2,558	713	619	539
27) Platt 43-28H	73%	59%	04/08/10	2,251	883	791	727
28) Meiers 11-17H	88%	71%	04/01/10	2,393	871	742	688
29) Annala 12-33H	78%	64%	03/26/10	2,730	927	869	832
30) Smith 12-7H	79%	64%	03/21/10	2,736	909	751	696
31) Leo 12-29H	93%	75%	03/18/10	3,474	1,210	937	821
32) TTT Ranch 21-26H	25%	21%	03/15/10	2,471	1,040	905	814
33) Kinnoin 21-14H	52%	42%	03/11/10	2,559	1,478	1,401	1,276
34) TTT Ranch 12-6H	43%	35%	03/07/10	2,987	1,212	992	895
35) Patten 44-3H	95%	77%	03/01/10	2,294	1,164	1,135	1,068
36) Sorenson 11-3H	38%	31%	02/19/10	2,770	1,736	1,594	1,513
37) Fladeland 11-10H	70%	56%	02/14/10	1,929	838	679	590
38) TTT Ranch 43-4H	31%	26%	02/02/10	1,853	922	673	647
39) Ness 44-21H	73%	60%	01/20/10	3,278	1,209	1,059	953
40) Rigel State 12-16H	32%	26%	01/17/10	3,205	945	940	877
41) Kannianen 44-33H	73%	60%	01/10/10	3,767	1,668	1,383	1,259
42) Iverson 11-14H	47%	38%	01/03/10	1,906	824	680	600
2010 Averages	60%	49%		2,617	1,063	957	893
2008 through 2010 Averages	61%	50%		2,323	955	818	742

30-, 60- and 90-day Average Production Rates for Whiting Operated Three Forks Wells in Sanish Field

2010 Wells	WI	NRI	Test Date	IP (BOE/d) 24-hr. Test	Average 1st 30 Days (BOE/d)	Average 1st 60 Days (BOE/d)	Average 1st 90 Days (BOE/d)
1) Marmon 12-18TFH [(1)]	99%	81%	08/31/10	1,182			
2) TTT Ranch 4-6TFH	43%	35%	08/16/10	1,768			
3) KR State 11-16TFH	25%	20%	06/26/10	1,298	543	424	
4) Foreman 11-4TFH	46%	38%	06/24/10	1,447	702	515	
5) Olson 11-14TFH	21%	17%	06/05/10	1,640	686	601	
6) Anderson 11-7TFH	47%	38%	01/29/10	1,262	460	404	382
2009 Wells							
7) Ogden 11-3TFH	57%	47%	11/10/09	1,479	632	534	464
8) Hansen 21-3TFH	50%	41%	06/10/09	551	300	257	255
9) Braaflat 21-11TFH	97%	79%	01/01/09	1,005	362	314	282
2010 Averages	47%	38%		1,433	598	486	382
2009 / 2010 Averages	54%	44%		1,292	526	436	346

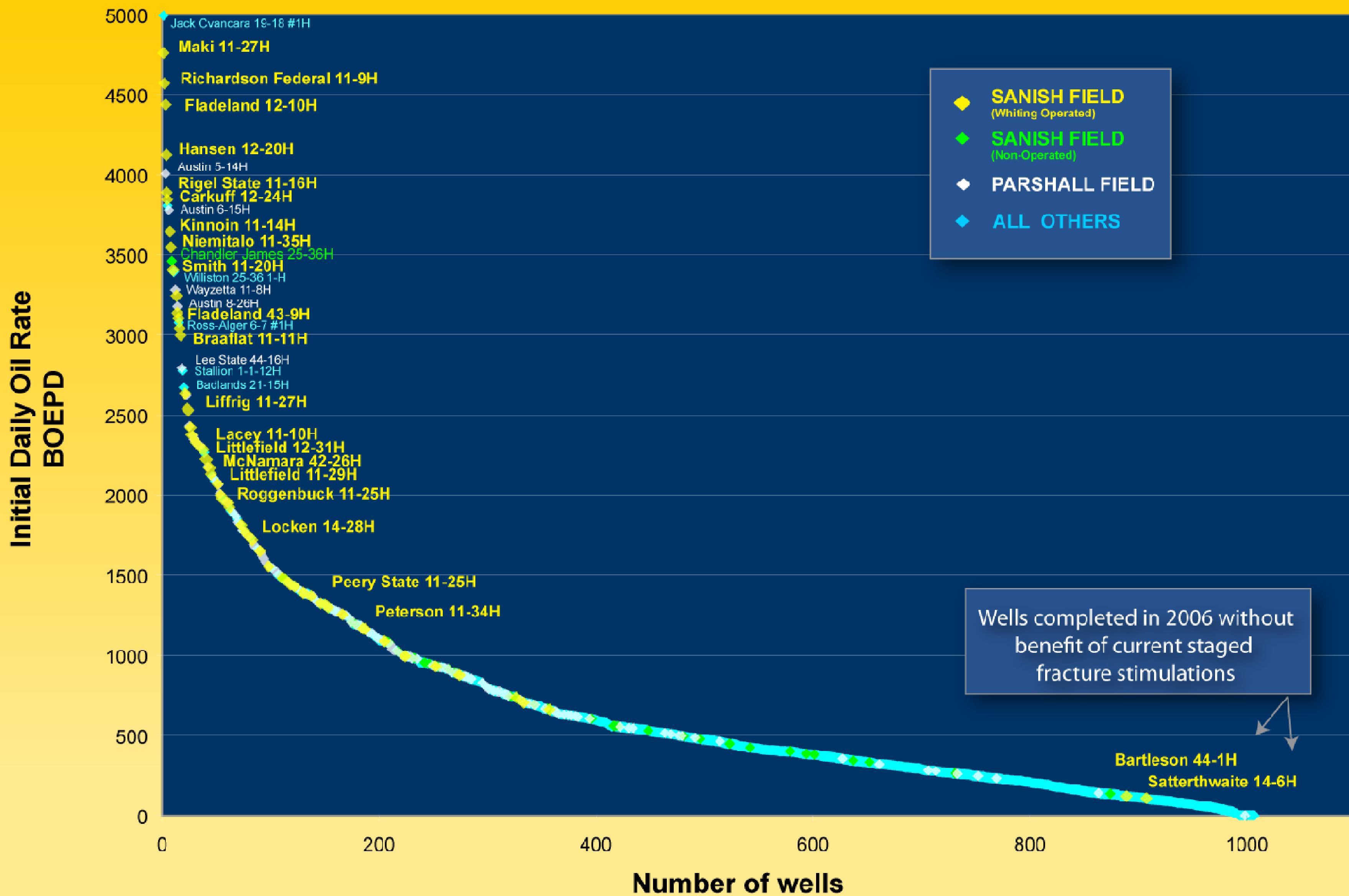
(1) Monitor well that was fracture stimulated in 10 stages.

Reported Initial Daily Rate (BOEPD)

North Dakota Middle Bakken Horizontal Wells since 2000

North Dakota Industrial Commission + Public Announcements

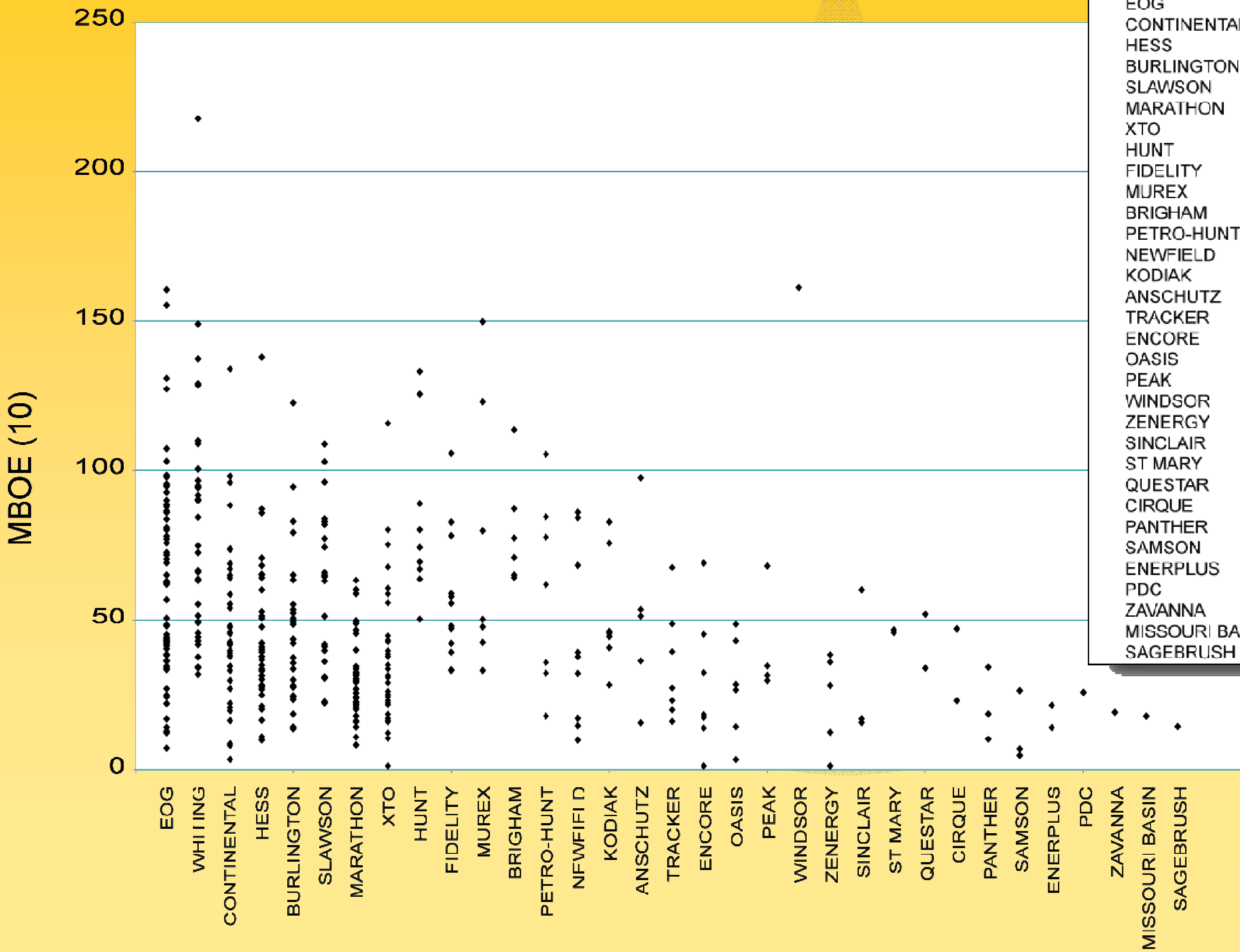
July, 2010



Six Month Cumulative Production by Operator For Bakken Wells Drilled Since January 2009

Source: North Dakota Industrial Commission + Montana Board of Oil & Gas
July, 2010

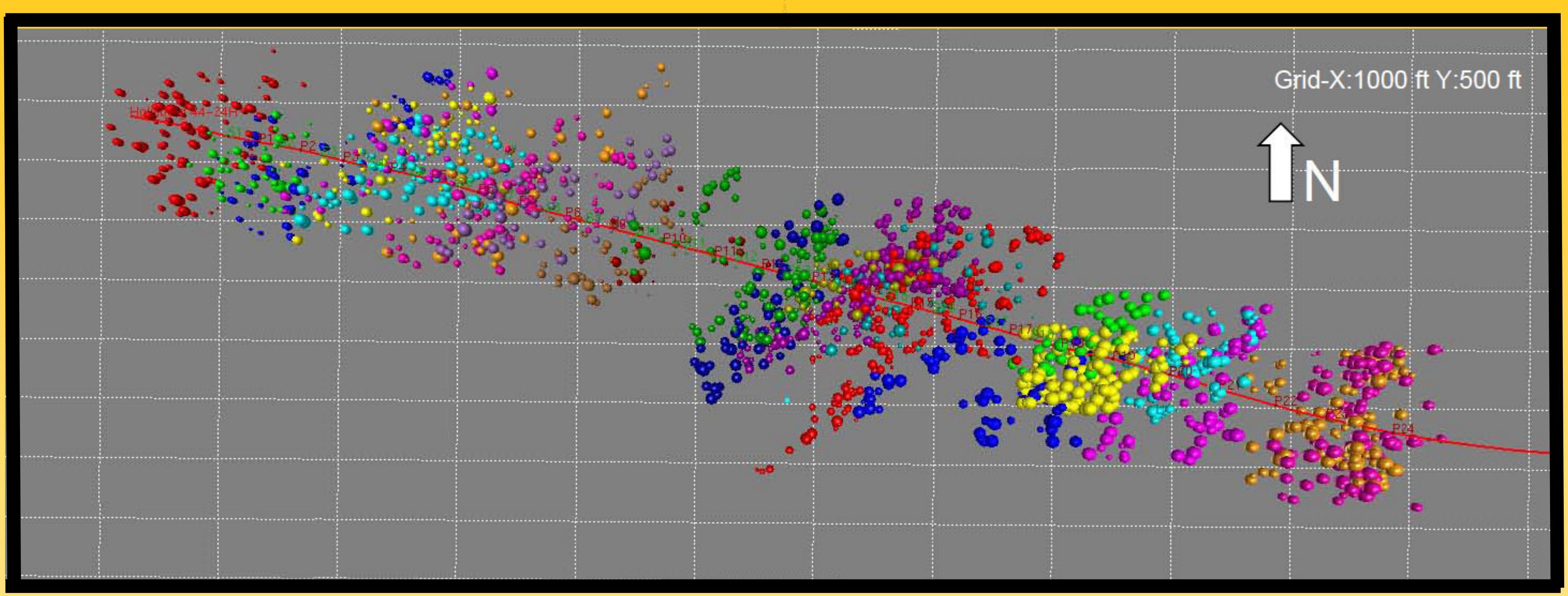
WHITING



	6 mo Total Production (MBOE10)	Wells Drilled	Average per Well (MBOE10)
WHITING	**2,796**	**35**	**80**
EOG	4,342	71	61
CONTINENTAL	1,998	41	49
HESS	1,637	37	44
BURLINGTON	1,329	29	46
SLAWSON	1,313	22	60
MARATHON	1,264	41	31
XTO	1,155	32	36
HUNT	752	9	84
FIDELITY	681	12	57
MUREX	526	7	75
BRIGHAM	478	6	80
PETRO-HUNT	415	7	59
NEWFIELD	389	9	43
KODIAK	363	7	52
ANSCHUTZ	254	5	51
TRACKER	242	7	35
ENCORE	197	7	28
OASIS	192	7	27
PEAK	164	4	41
WINDSOR	161	1	161
ZENERGY	116	5	23
SINCLAIR	93	3	31
ST MARY	92	2	46
QUESTAR	86	2	43
CIRQUE	70	2	35
PANTHER	63	3	21
SAMSON	38	3	13
ENERPLUS	35	2	18
PDC	26	1	26
ZAVANNA	19	1	19
MISSOURI BASIN	18	1	18
SAGEBRUSH	14	1	14

Microseismic Events

Recorded during fracture stimulation of the Holmberg 44-28H



- 24-Stage Frac / IP: 2,558 BOE/D
- Excellent "frac saturation" evidenced by minimal gaps of unfraced rock along the wellbore with some overlapping stages impacting the same rock volume.
- Well developed NE-trending natural fractures indicated in some locations.
- Lateral frac wings average 750' on either side of the wellbore. This is consistent with our other fracs and planned spacing pattern for full field development.

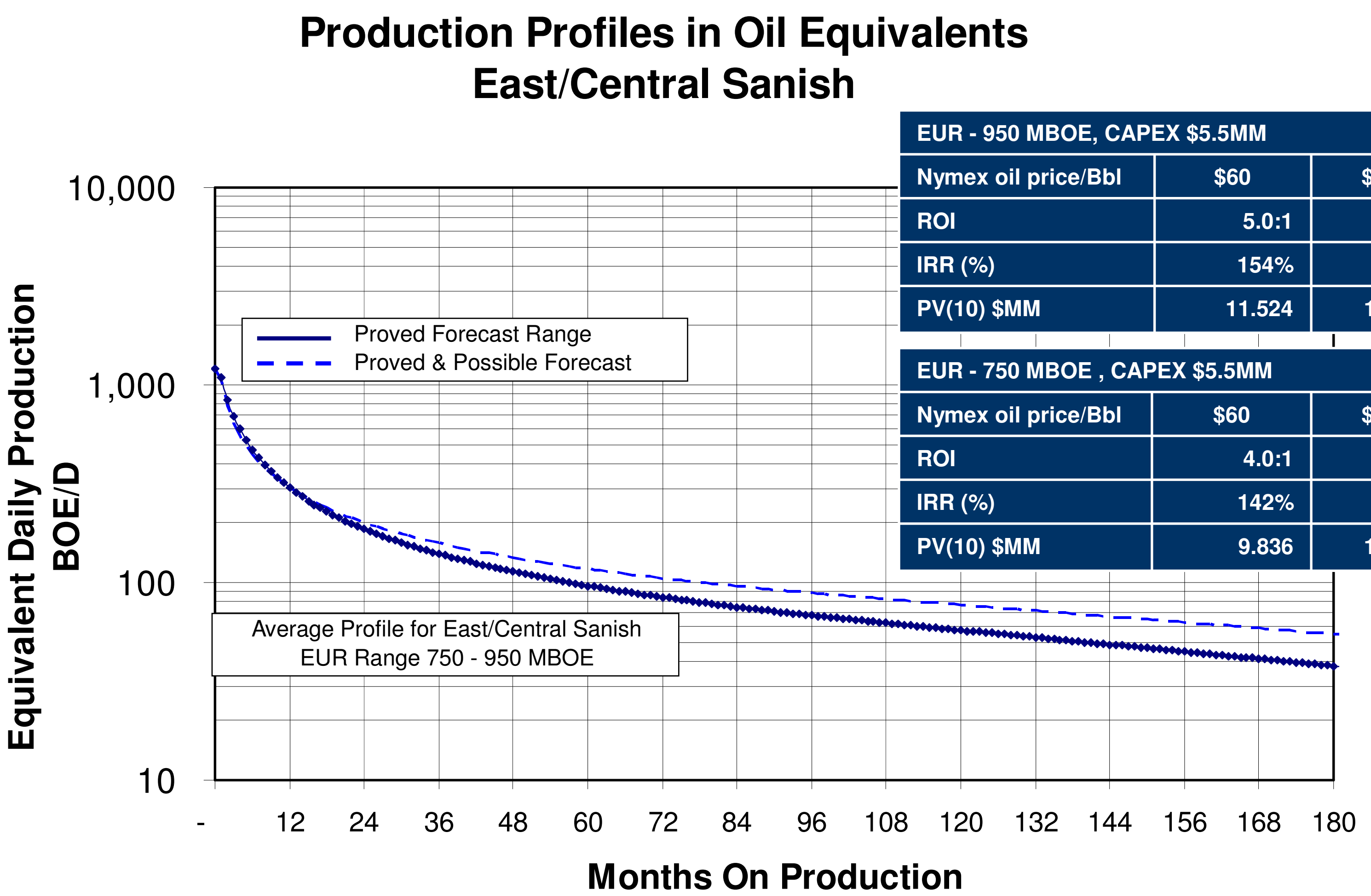
Whiting's Sanish Field Track Record

Installed 1,242 sleeves in 94 wells (thru 5/10)

- **20 intervals "tight": (1.6%)**
- **8 sleeves (4 wells) not opened: (0.8%)**
- **5 sleeves skipped due to human error: (0.4%)**
- Successfully pumped: 987 sleeves (97.6%)

Typical Bakken Production Profile
East/Central Sanish (1) (2)

WHITING



EUR - 950 MBOE, CAPEX $5.5MM			
Nymex oil price/Bbl	$60	$70	$80
ROI	5.0:1	6.2:1	7.3:1
IRR (%)	154%	233%	349%
PV(10) $MM	11.524	15.060	18.579

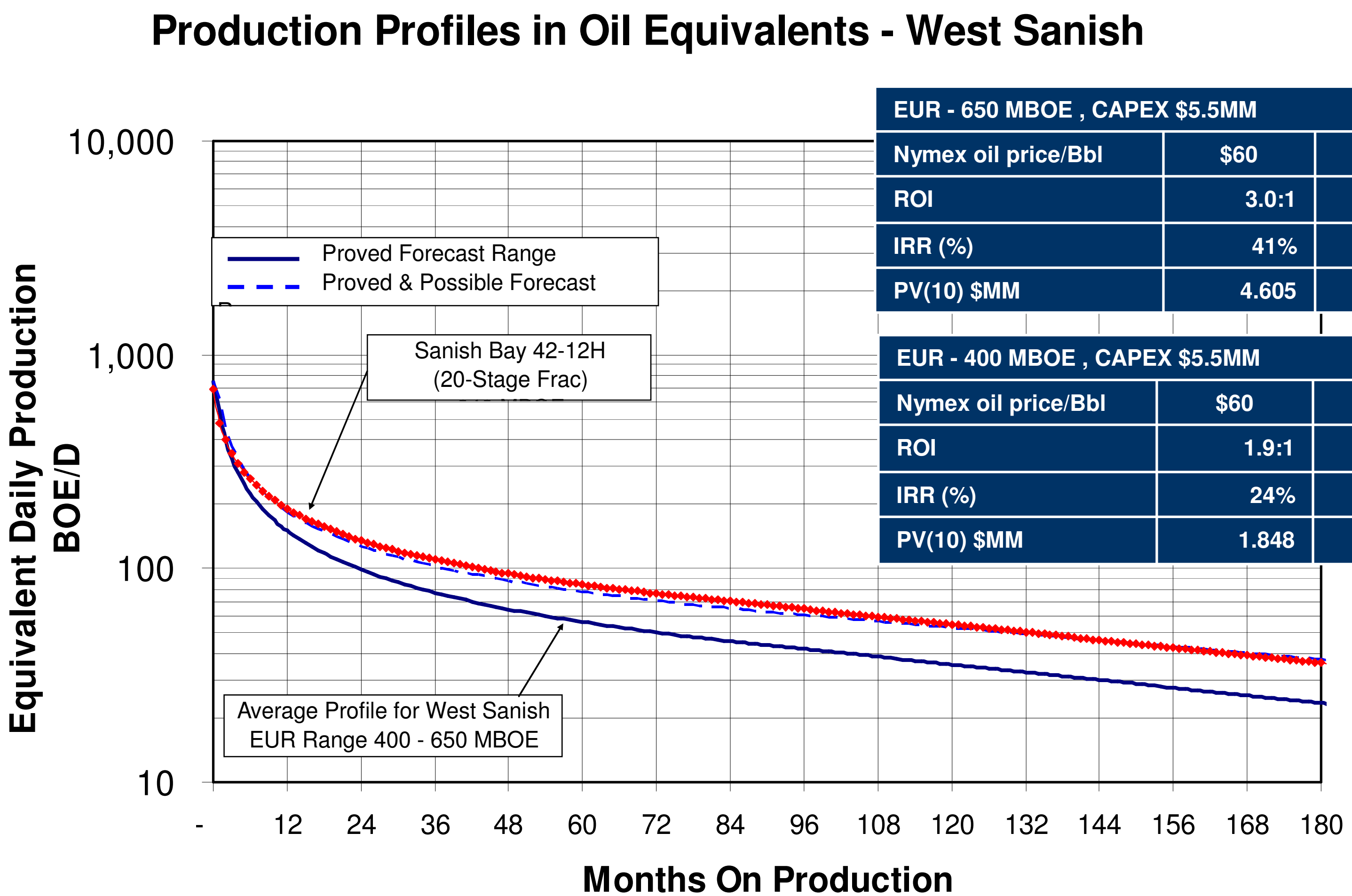
EUR - 750 MBOE , CAPEX $5.5MM			
Nymex oil price/Bbl	$60	$70	$80
ROI	4.0:1	4.9:1	5.8:1
IRR (%)	142%	198%	314%
PV(10) $MM	9.836	13.046	16.258

(1) **Based on independent engineering by Cawley Gillespie & Associates, Inc. at 12/31/09. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.**

(2) **EURs, ROIs, IRRs and PV10 values will vary well to well. Whiting holds an average WI of 61% and an average NRI of 50% in its operated wells in Sanish field.**

Typical Bakken Production Profile
West Sanish (1) (2) (3)

WHITING



EUR - 650 MBOE , CAPEX $5.5MM			
Nymex oil price/Bbl	$60	$70	$80
ROI	3.0:1	3.7:1	4.4:1
IRR (%)	41%	63%	87%
PV(10) $MM	4.605	6.830	9.056

EUR - 400 MBOE , CAPEX $5.5MM			
Nymex oil price/Bbl	$60	$70	$80
ROI	1.9:1	2.4:1	2.9:1
IRR (%)	24%	37%	56%
PV(10) $MM	1.848	3.541	5.237

(1) **Based on independent engineering by Cawley Gillespie & Associates, Inc. at 12/31/09. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.**

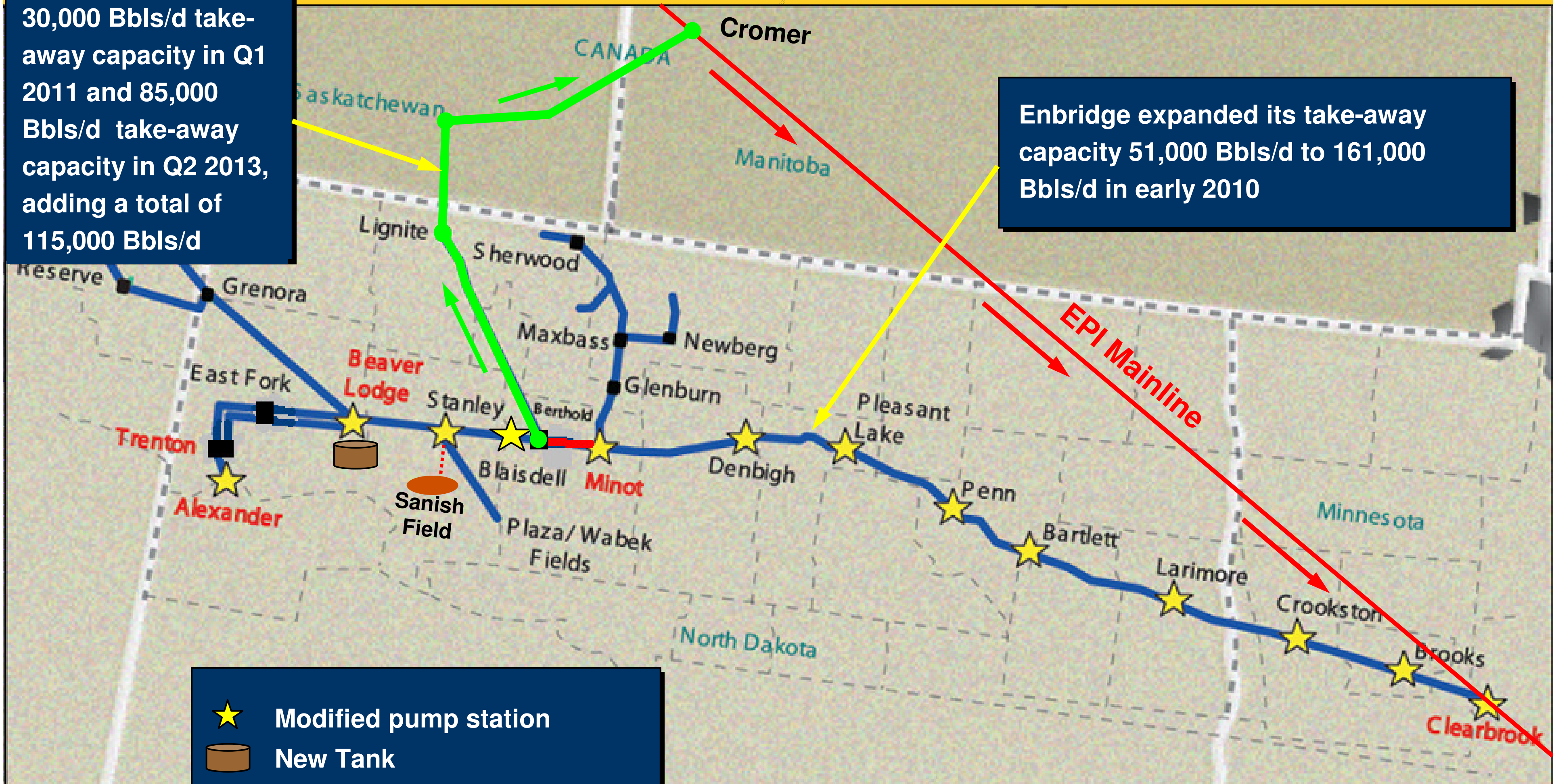
(2) **EURs, ROIs, IRRs and PV10 values will vary well to well. Whiting holds an average WI of 61% and an average NRI of 50% in its operated wells in Sanish field.**

(3) **Future wells in the western portion of Sanish field will be fraced in 22 - 30 stages.**

Enbridge Pipeline Expansion [1]

Enbridge to add 30,000 Bbls/d take-away capacity in Q1 2011 and 85,000 Bbls/d take-away capacity in Q2 2013, adding a total of 115,000 Bbls/d

Enbridge expanded its take-away capacity 51,000 Bbls/d to 161,000 Bbls/d in early 2010



- Modified pump station
- New Tank

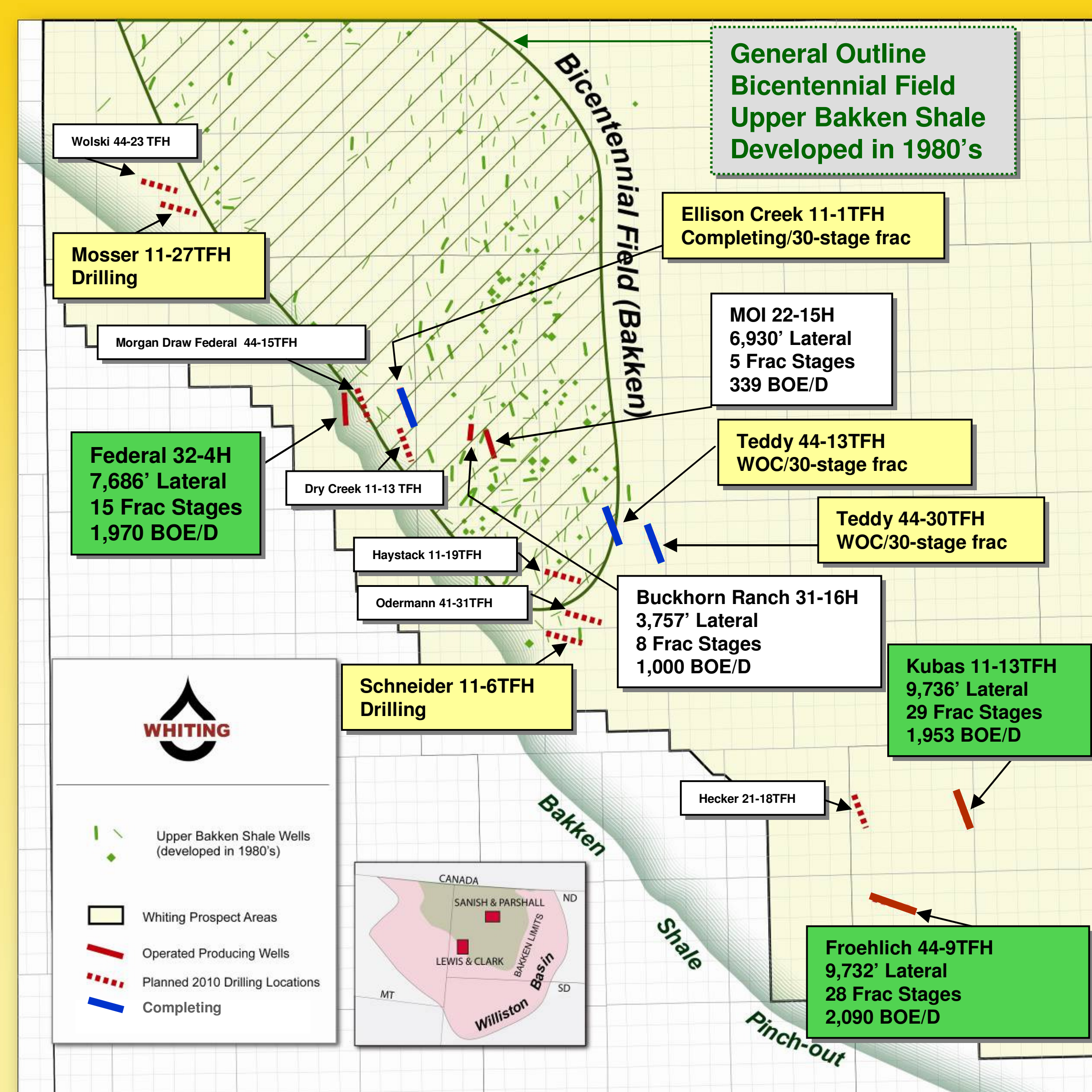
(1) Whiting expects that approximately 67% of its operated production from the Sanish field will be sold via the Sanish field to Enbridge pipeline during the third quarter of 2010.

Finding Cost Comparison

	Eagle Ford Oil[1]	Haynesville Gas[2]	Pinedale Gas[3]	Bakken Oil[4]
Gross EUR (BCFE)	3.1	7.5	6.5	5.1
Gross Well Cost ($MM)	5.5	8.5	5.0	5.5
6:1 Conversion				
Net EUR (MBOE)	385	938	867	697
F&D Cost ($ / BOE)	14.29	9.07	5.77	7.89
F&D Cost ($ / MCFE)	2.38	1.51	0.96	1.32
13:1 Conversion				
Net EUR (MBOE)	385	433	400	697
F&D Cost ($ / BOE)	14.29	19.64	12.50	7.89
F&D Cost ($ / MCFE)	1.10	1.51	0.96	0.61

(1) EOG Resources; South Texas Eagle Ford Presentation, Slide #24
(2) PetroHawk Corporate Presentation, April 13, 2010, Slide #11
(3) Ultra Petroleum IPAA OGIS Symposium Presentation, April 12, 2010, Slide #15
(4) Whiting type curve average reserve of 850 MBOE

Lewis & Clark Area – 250 Units / 500 Potential Locations



OBJECTIVE

Upper Three Forks along pinch-out of the overlying Bakken Shale

ACREAGE

Whiting has assembled 340,241 gross (225,685 net) acres in our Lewis & Clark prospect area in the southwestern Williston Basin

This acreage position would allow up to 250 possible 1,280-acre spacing units within the prospective area:

- **123 units with > 50% WI**
- **127 units with < 50% WI**
- **Average WI of 67%**
- **Average NRI of 57%**
- **Well by well WI and NRI will vary based on ownership in each spacing unit**

ECONOMICS

Well Cost: $6 MM per well
EUR: 350 to 500 MBOE

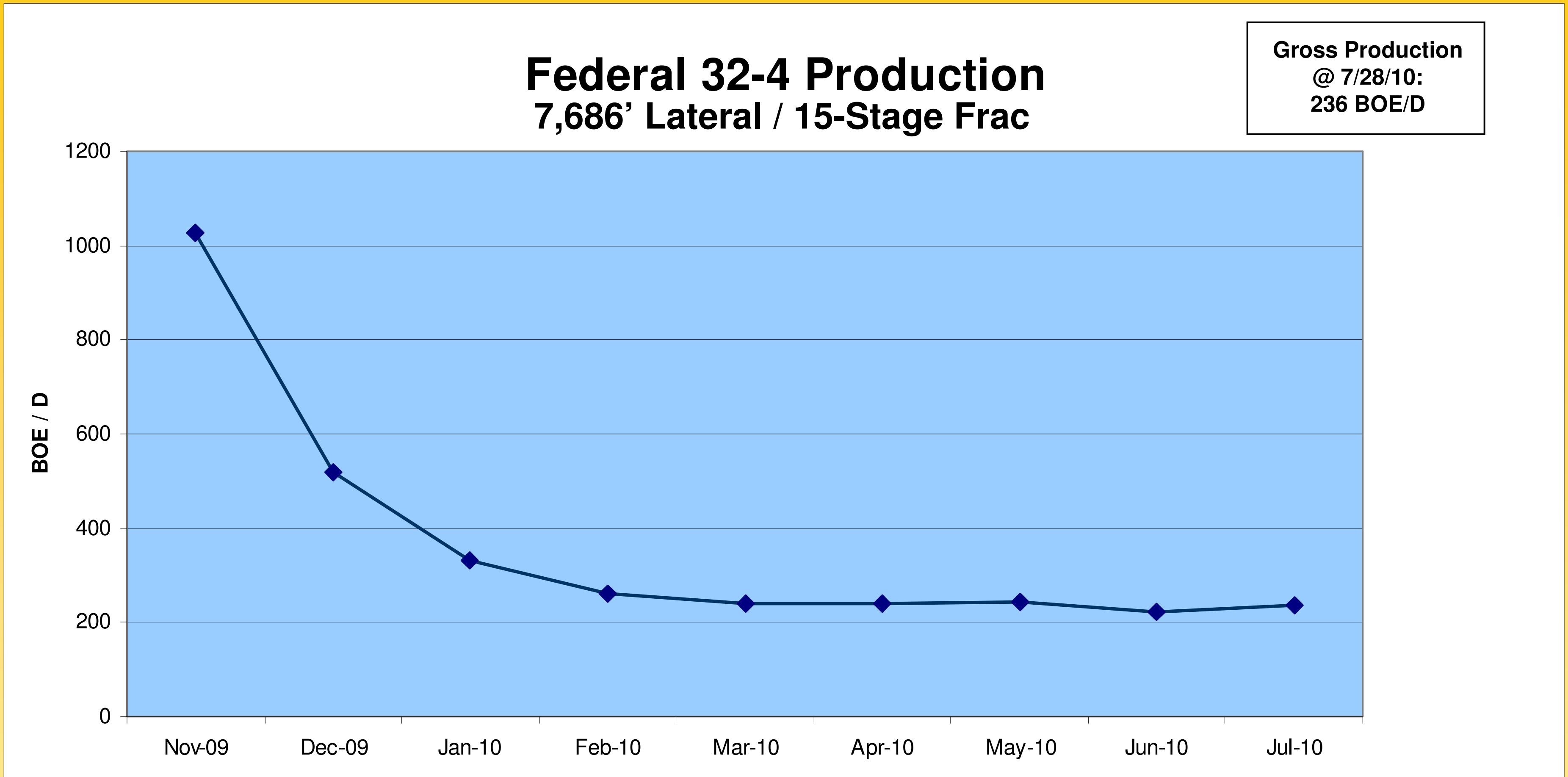
DRILLING PROGRAM

Current 13-well program began in May 2010 with three drilling rigs. A fourth rig was added in August 2010 and a fifth rig is expected to be added in November 2010. Planned CapEx for 2010 is $77 MM.

FEDERAL 32-4H DISCOVERY WELL

IP: 1,970 BOE/D. Average rate during first 30, 60 and 90 days of production was 695 BOE/D, 531 BOE/D and 447 BOE/D, respectively.

Production History of Federal 32-4 Well at Lewis & Clark (1) (2) (3)



(1) The table above reflects production from November 23, 2009 through July 28, 2010.

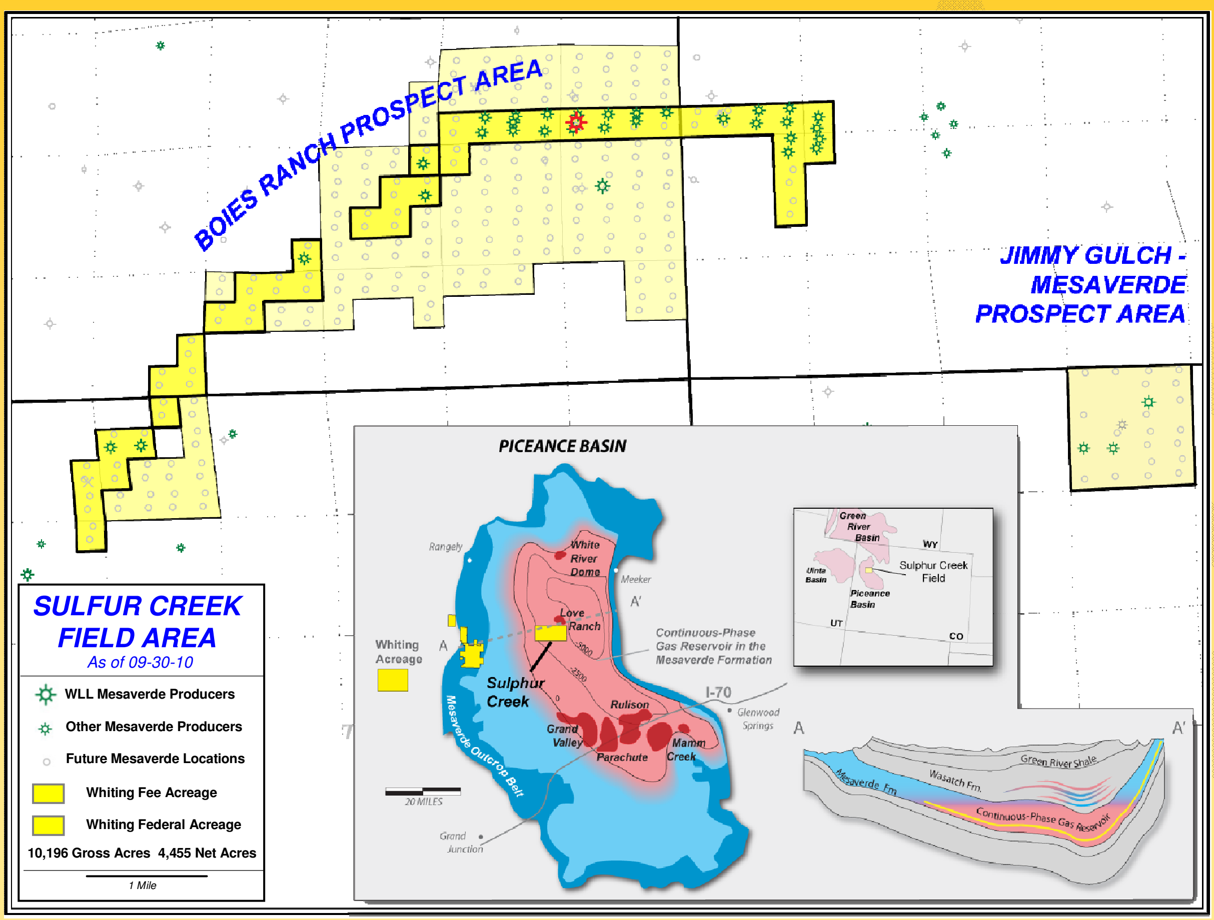
(2) The Federal 32-4 was completed in the Three Forks formation on 11/23/09 flowing 1,970 BOE/D.

(3) Total monthly production from all Whiting-operated wells in North Dakota is reported to the North Dakota Industrial Commission (NDIC) at approximately the end of the following month. The NDIC included only 8 days of production from the Federal 32-4 in November 2009. Thus, the NDIC reported total production in the first six months for the Federal 32-4 to be 51,000 BOE during a 159-day period.

NOTE: Production in the first six months (181 days) totaled 66,300 BOE.

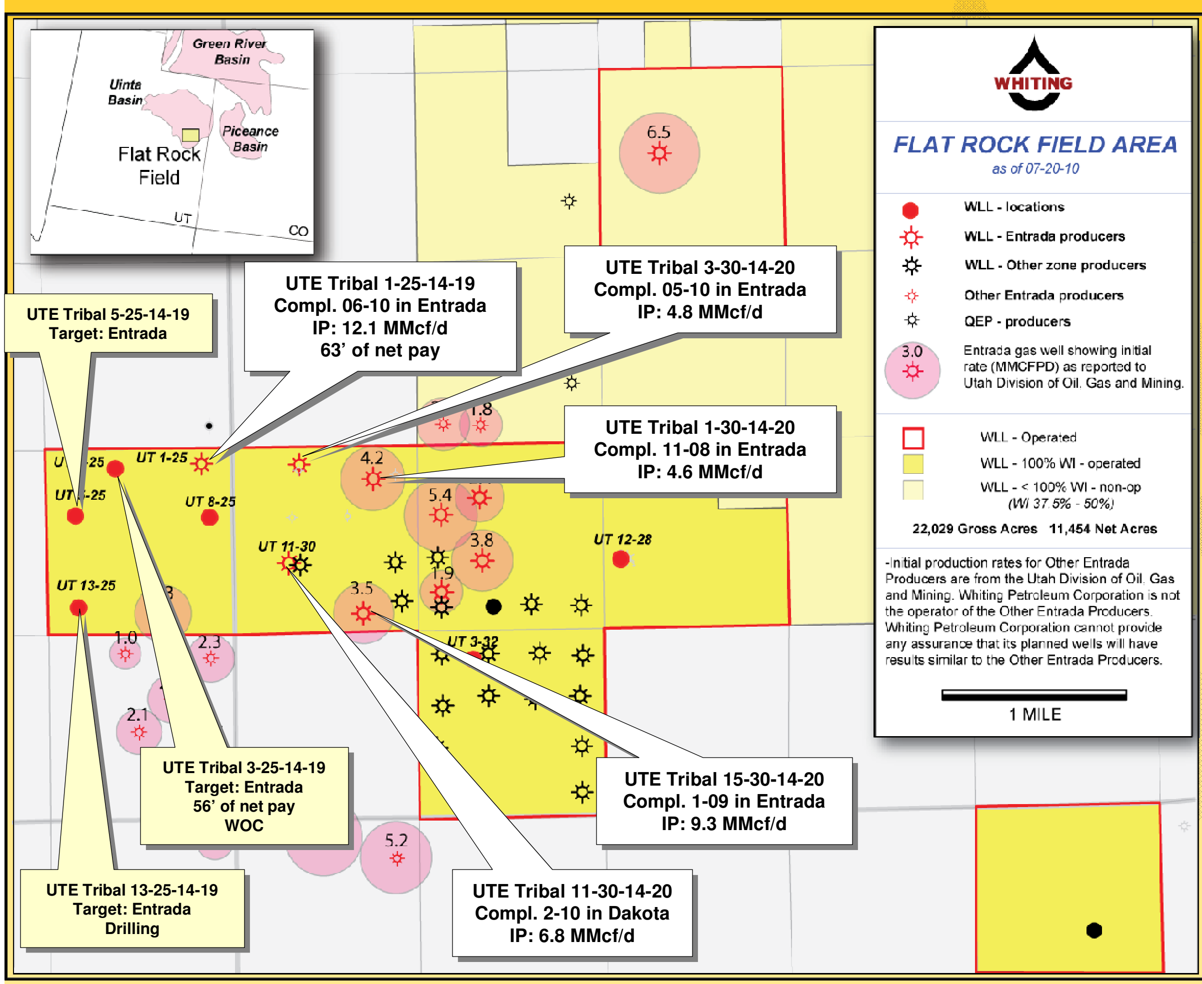
Sulphur Creek Field (Boies Ranch and Jimmy Gulch)

Rio Blanco County, Colorado



- Whiting's net production from the Sulphur Creek field in Rio Blanco County, Colorado, was 4.2 MMcf per day as of September 26, 2010
- Whiting owns 10,196 gross (4,455 net) acres in the Sulphur Creek field area
- 32 Mesaverde wells have been drilled and 228 20-acre potential locations remain
- Jimmy Gulch prospect (Mesaverde completion interval):
  - One square mile extension of Boies Ranch prospect
  - 3 wells are producing and an additional 29 locations have been identified on 20-acre spacing
- Whiting has a five-year gas sales contract at a flat fixed-price of $5.34 per Mcf at the wellhead. The contract covers daily volumes of 5 MMcf through year-end 2010, 4 MMcf in 2011, 3 MMcf in 2012, 2 MMcf in 2013, and 1 MMcf in 2014. (Please refer to slide #53.)

Flat Rock Field
Uintah County, Utah



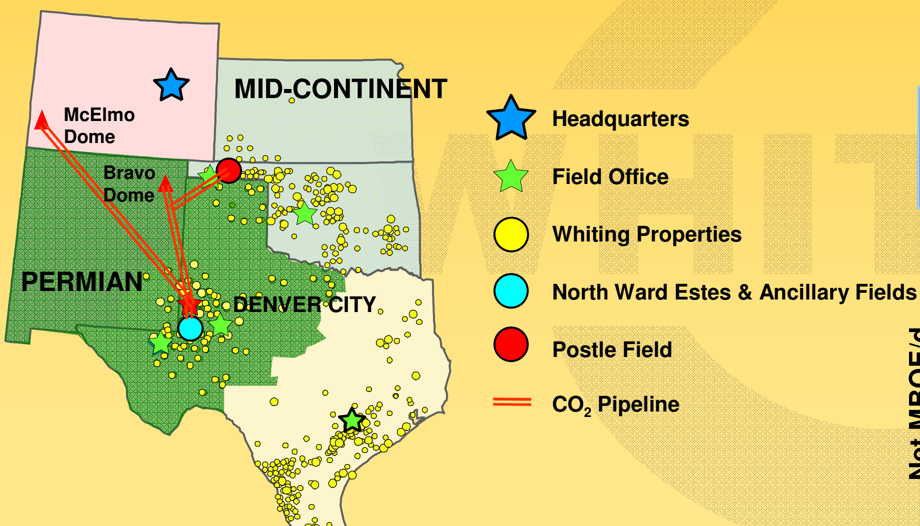
- **22,029 gross acres (11,454 net)**
- **17.7 MMcfe of daily net production as of September 26, 2010**
  - **10 wells in the Entrada formation (11,500 feet)**
  - **25 wells in the Wasatch and Dakota formations**
- **95% of current production is from the Entrada formation**
  - **49 square miles of 3-D seismic support**
  - **Up to 100 feet of net pay**
  - **27 additional drilling locations**
- **On February 12, 2010, Whiting completed the Ute Tribal 11-30-14-20 well in the Dakota formation flowing 6.8 MMcf/d**
- **A 3-well Entrada drilling program commenced in July 2010.**
- **Whiting has a five-year gas sales contract covering 10 MMcf of gas per day at a flat fixed-price of $5.50 per Mcf at the wellhead. In 2010 and 2011, an additional 5 MMcf of daily gas volumes are under contract at a flat fixed-price of $5.38 per Mcf at the wellhead. (Please refer to slide #53.)**

Source: Utah Oil and Gas Commission as of September 1, 2008

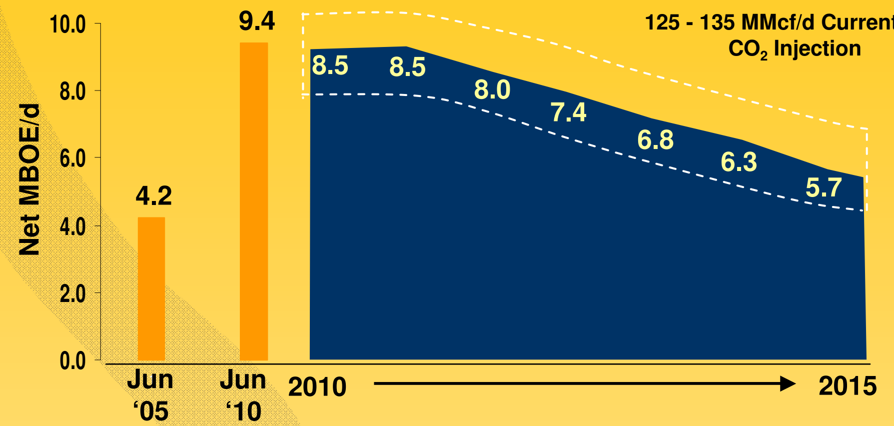
EOR Projects - Postle and North Ward Estes Fields (1)

	Whiting	Postle N. Ward Estes	Total Whiting	% Postle N. Ward Estes
12/31/09 Proved Reserves				
Oil – MMBbl	99.2	124.6	223.8	56%
Gas – Bcf	264.7	42.7	307.4	14%
Total – MMBOE	143.3	131.7 (1)	275.0	48% (1)
% Crude Oil	68%	95%	81%	
Q2 2010 Production				
Total – MBOE/d	47.3	17.3	64.6	27%

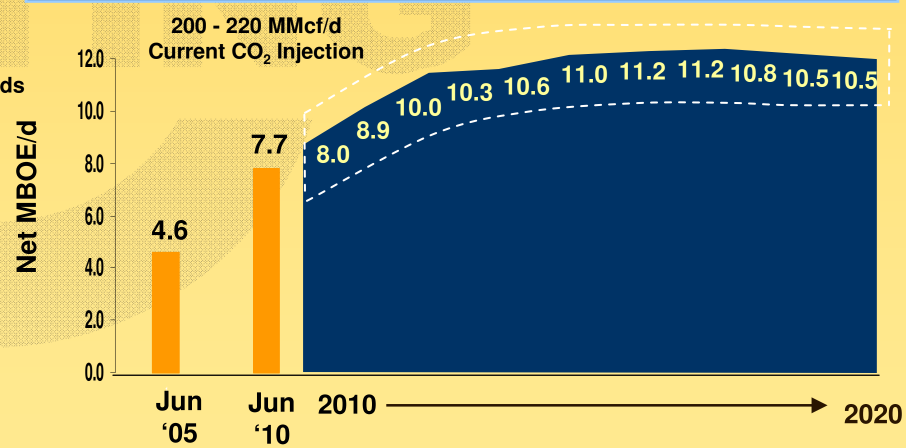
(1) Includes Ancillary Properties



Postle Field Proved Reserve Production Forecast (2)



North Ward Estes Field Proved Reserve Production Forecast (3)



Range of results may be at least +/- 10%

(1) Based on independent engineering by Cawley, Gillespie & Associates, Inc. at December 31, 2009. Includes ancillary fields. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(2) Production growth based on assumptions in December 31, 2009 reserve report. After 2015, Postle field proved reserve production is expected to decline at 8% - 10% year over year.

(3) Production growth based on assumptions in December 31, 2009 reserve report. After 2020, North Ward Estes field proved reserve production is expected to decline at 4% - 6% year over year.

Total Postle, N. Ward Estes and Ancillary Properties

Fully Developed Costs Per BOE

	Net (MM$)	Reserves or Production (Net MMBOE)	Acq. and Dev. Cost ($/BOE)
Acquisition Purchase Price (effective 7/1/05)	$ 802		
Remaining Proved at 12/31/09 – Capex / Reserves	920 [1]	131.7 [1] [2] [3]	
Six Months 2005 – Capex / Production	55	1.9	
2006 – Capex / Production	243	4.4	
2007 – Capex / Production	283	4.2	
2008 – Capex / Production	326	4.6	
2009 – Capex / Production	165	5.3	
2006 – 2008 Divestments – Sales Price	(23)	--	
2009 Acquisitions – Purchase Price	66	--	
Total Actual Plus Proved at 12/31/09 – Capex / Reserves	2,837 [1]	152.1 [1] [2]	$18.65 [1]
Probable and Possible at 12/31/09 – Capex / Reserves	715 [1] [4]	131.8 [1] [2]	
Total Actual Plus All Reserve Cats. – Capex / Reserves	$3,552 [1]	283.9 [1] [2]	$12.51 [1]

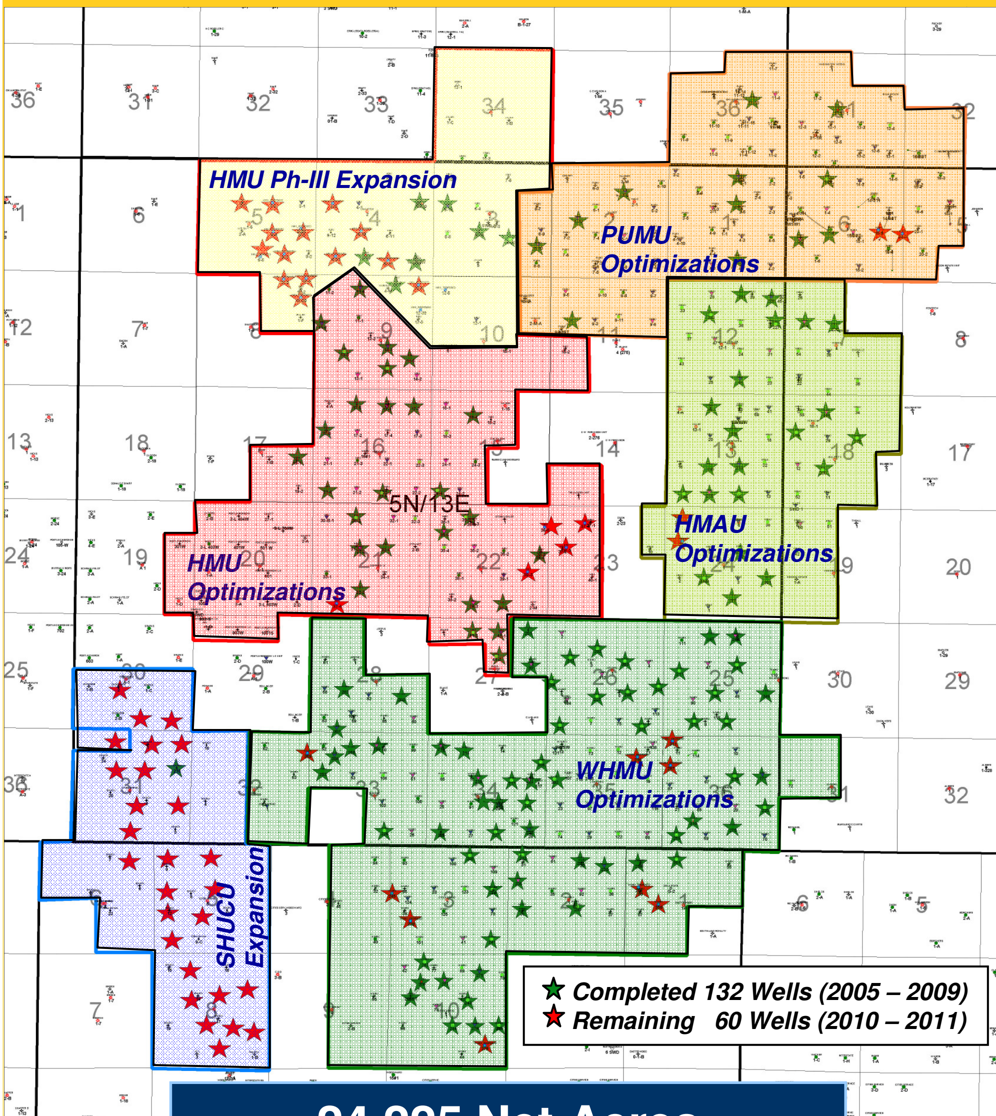
(1) Based on 12-month average prices of $61.18/Bbl and $3.87/Mcf in accordance with SEC requirements.

(2) Based on independent engineering by Cawley Gillespie & Associates, Inc. at December 31, 2009. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(3) The estimated proved reserves at acquisition in June 2005 was 122.3 MMBOE.

(4) Includes $40 million for Ancillary properties.

Development Plans – Postle Field
Texas County, Oklahoma



24,225 Net Acres

Total Remaining Capital Expenditures [1] (In Millions)

	CapEx [2]
Drilling, Completion, Workovers & Dry Trail Gas Plant Costs (thru 2013)	$ 105
CO_2 Purchases (thru 2015)	31
Total	$ 136

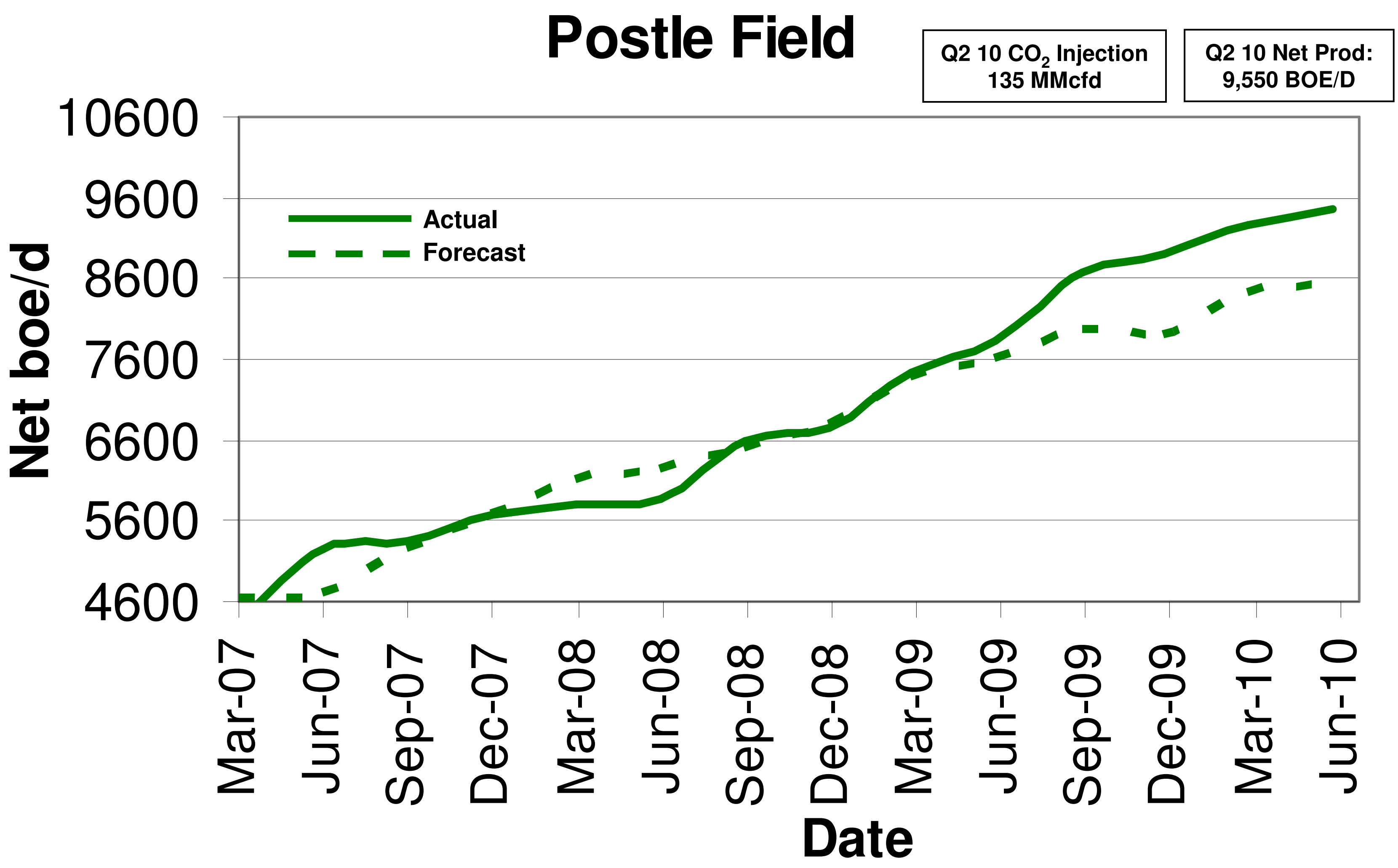
(1) Based on independent engineering at Dec. 31, 2009.

(2) Consists of CapEx for Proved, Probable and Possible reserves. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information."

Postle Quarterly Average Net BOE/D Production

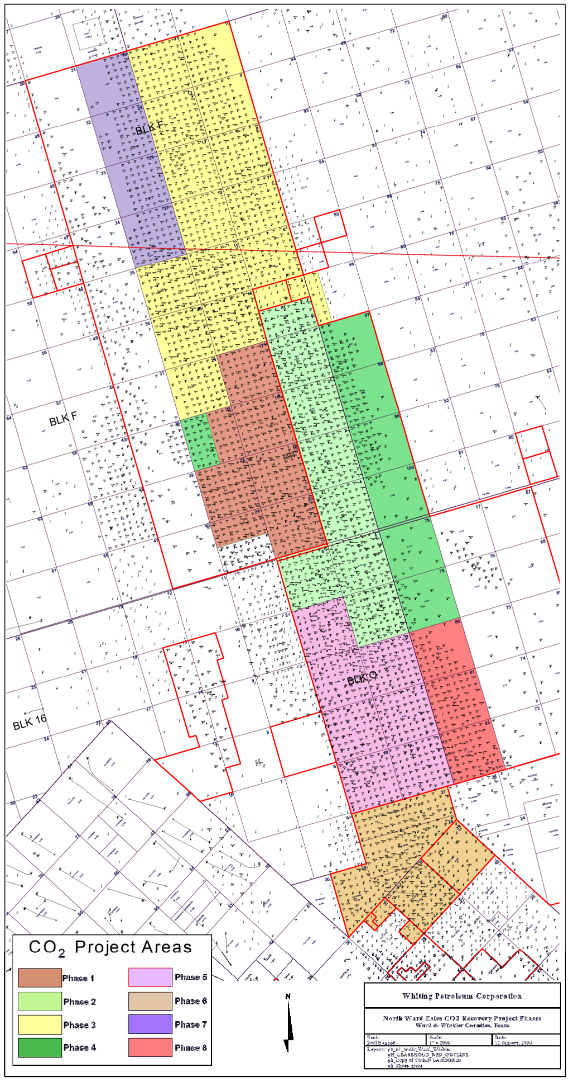
Q2 10 CO_2 Injection
135 MMcfd

Q2 10 Net Prod:
9,550 BOE/D



Development Plans – North Ward Estes Field

Ward and Winkler Counties, Texas



58,000 Net Acres

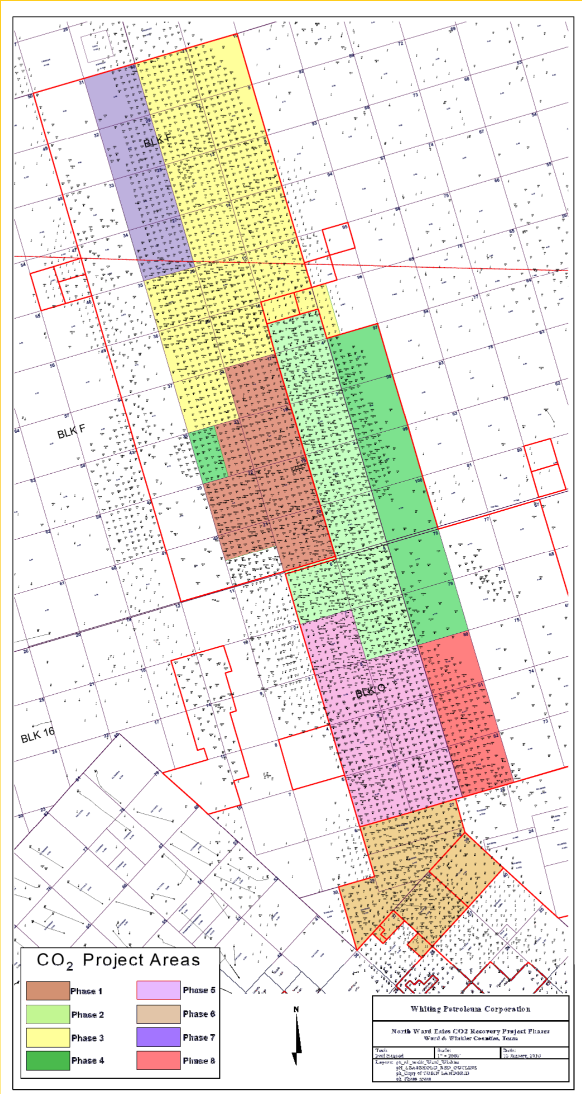
Project Timing and Net Reserves (1)

CO_2 Project	Injection Start Date	PVPD	Other Proved	P2	P3	Total
Primary & WF		15	15	1	9	40
Phase 1	2007 - 2008	9	4	4	10	27
Phase 2	2009 - 2010	3	12	4	12	31
Phase 3	2010 - 2014	0	18	9	22	49
Phase 4	2011	0	3	1	3	7
Phase 5	2012 - 16	0	3	9	15	27
Phase 6	2020	0	8	4	9	21
Phase 7	2025	0	0	0	8	8
Phase 8	2027	0	0	0	4	4
	Totals (MMBOE)	27	63	32	92	214

(1) Based on independent engineering at Dec. 31, 2009. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

Development Plans – North Ward Estes Field

Ward and Winkler Counties, Texas



58,000 Net Acres

CO_2 Project	Injection Start Date
Phase 1	2007 - 2008
Phase 2	2009 - 2010
Phase 3	2010 - 2014
3A	2010
3B	2011
3C	2012
3D	2013
3E	2014
Phase 4	2011
Phase 5	2012 – 2016
5A	2012
5B	2015
5C	2016
Phase 6	2020
Phase 7	2025
Phase 8	2027

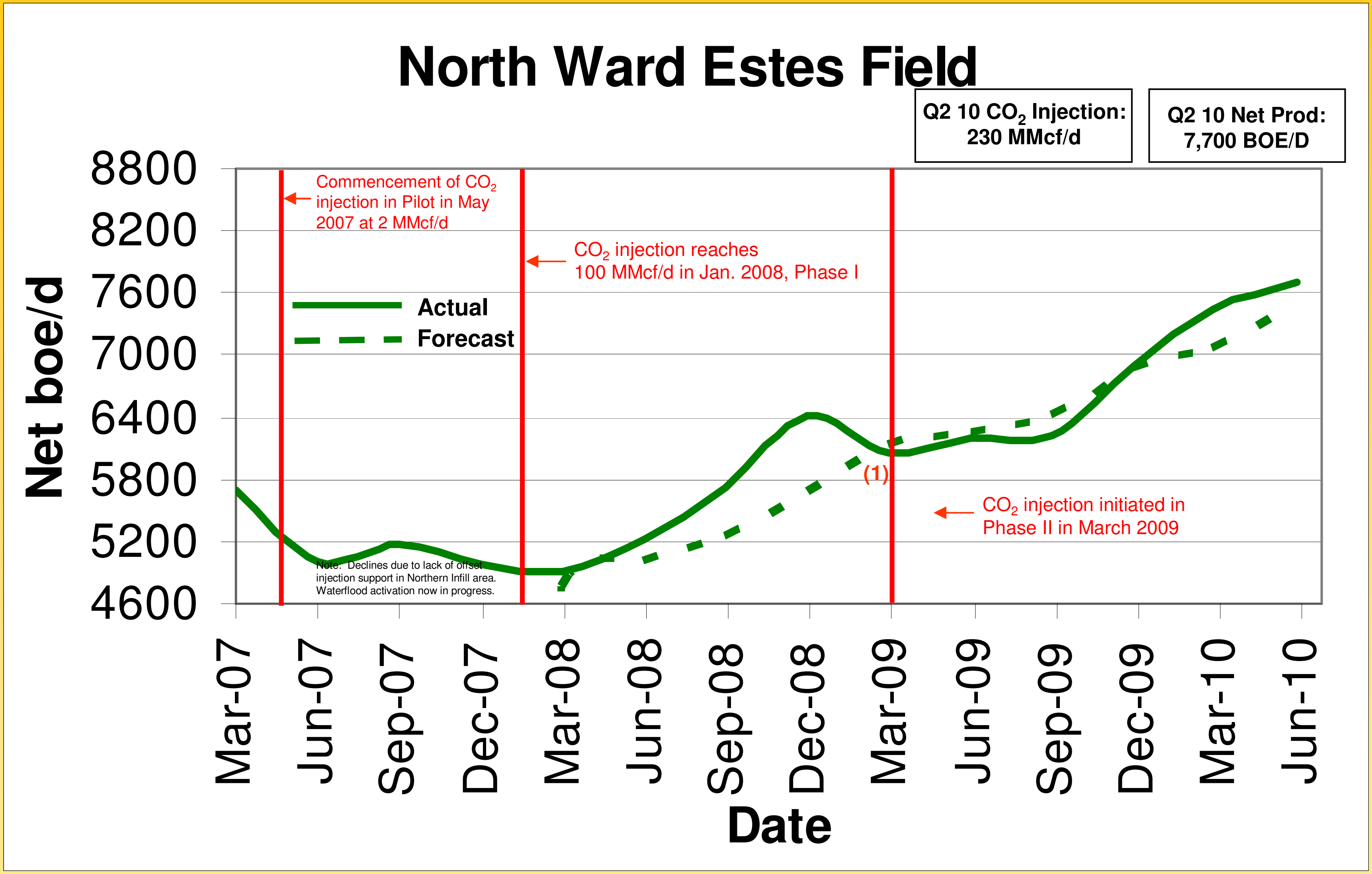
Total 2010 - 2030 Remaining Capital Expenditures (1)
(In Millions)

	CapEx (2)
Drilling, Completion, Workovers & Gas Plant Costs	$ 504
CO_2 Purchases	937
Total	$1,441

(1) Based on independent engineering at Dec. 31, 2009.

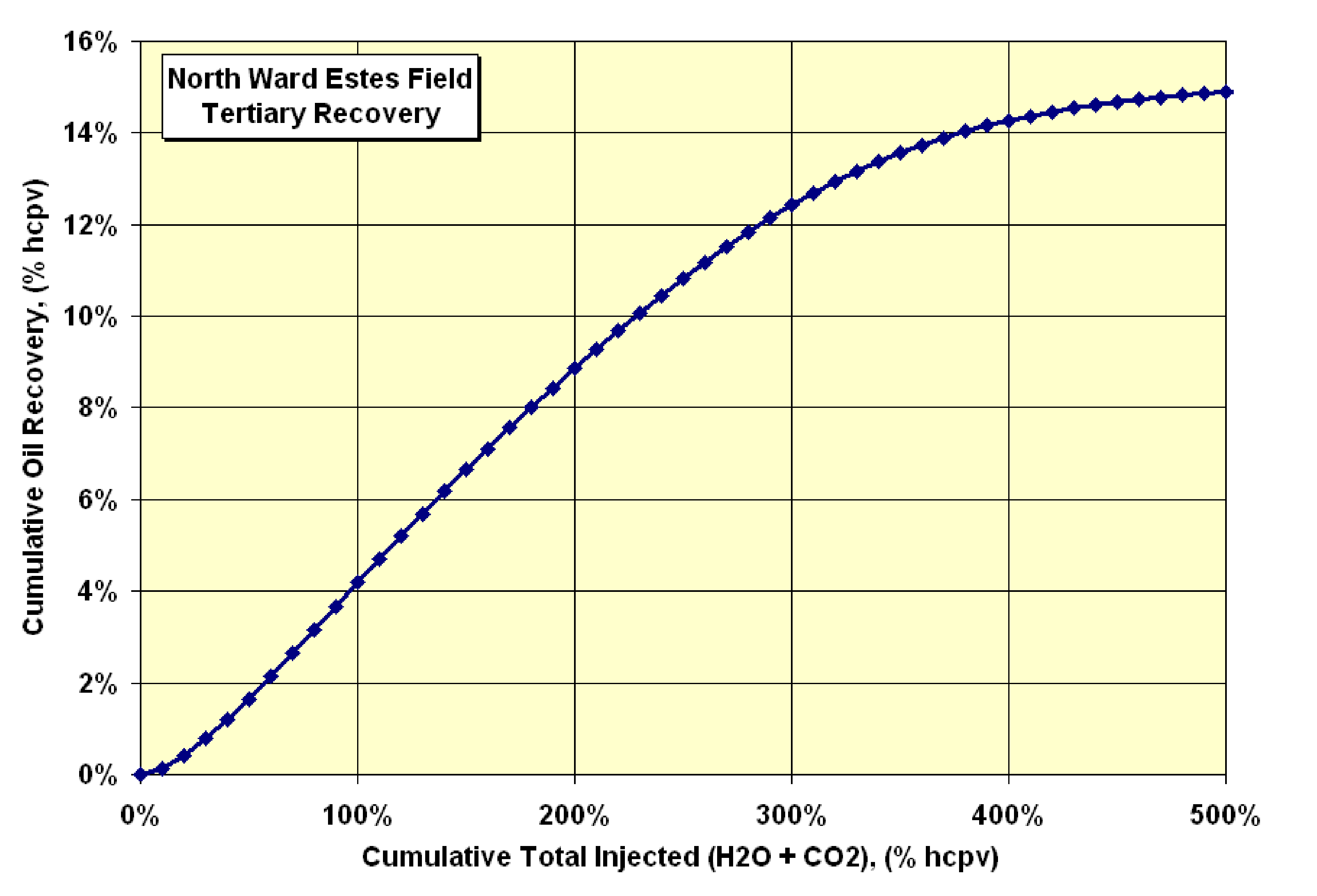
(2) Consists of CapEx for Proved, Probable and Possible reserves. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information."

North Ward Estes Quarterly Average Net BOE/D Production



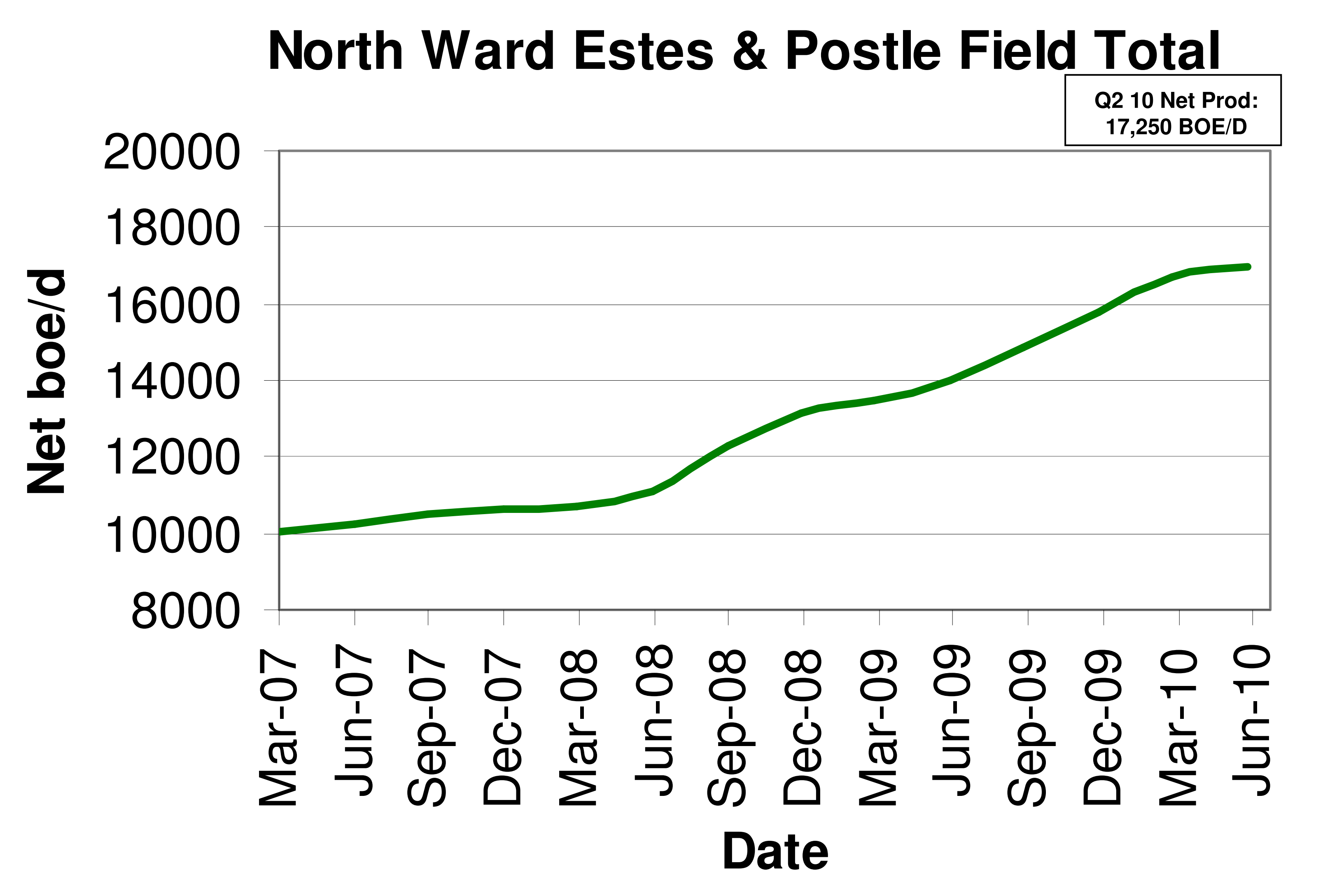
(1) Production decline was due to scaling problems that have been subsequently resolved with mechanical and chemical treatments.

Whiting Estimated Oil Recovery Type Curve from CO_2 Flood
North Ward Estes



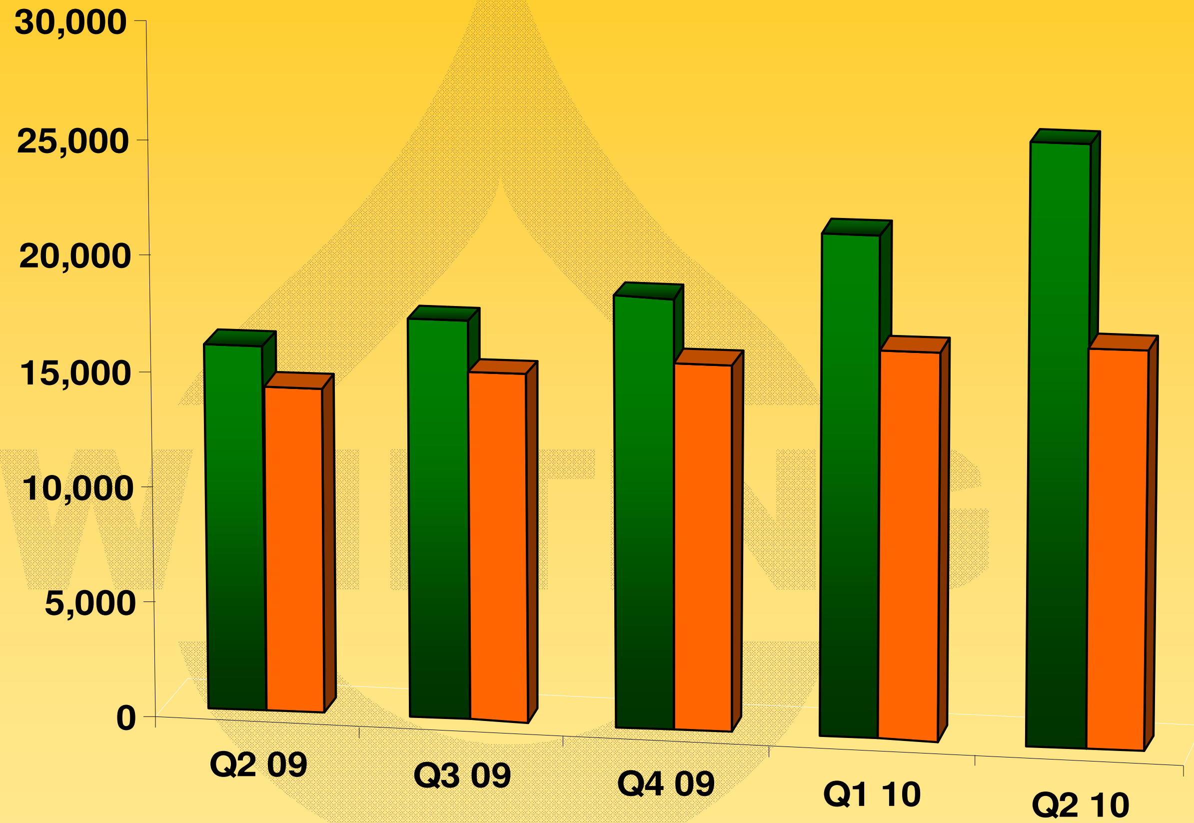
North Ward Estes and Postle Quarterly Average Net BOE/D Production

WHITING



Production Growth (in BOE/D)

Net Production from Bakken, Postle and N. Ward Estes



	Q2 09	Q3 09	Q4 09	Q1 10	Q2 10
Bakken	15,850	17,300	18,625	21,690	25,895
Postle / N.W.E	14,125	15,085	15,865	16,800	17,250
Total	29,975	32,385	34,490	38,490	43,145

Total Capitalization
($ in thousands)

	June 30, 2010	Redemption Adjustments	CPP Exchange Adjustments	Offering Adjustments	Pro Forma [1]
Cash and Cash Equivalents	$ 15,521	--	$ (15,521)	--	--
Long-Term Debt					
Credit Agreement	$ 30,000	$ 383,451	$ 34,403	$ (342,600)	$ 105,254
Senior Subordinated Notes	619,603	(369,603)	--	350,000	600,000
Total Long-Term Debt	$ 649,603				$ 705,254
Stockholders' Equity	$ 2,460,334	$ (11,306)	$ (49,924)	--	$2,399,105
Total Capitalization	$3,109,937				$3,104,359
Total Debt / Total Capitalization	20.9%				22.7%

[1] Pro forma for redemption of 2012 and 2013 notes, CPP exchange and the Offering.

Disciplined Hedging Strategy (1)

- Utilize hedges to manage exposure against potential commodity price declines while maintaining pricing upside
- Employ mix of contracts weighted toward the short-term

	Existing Crude Oil Hedge Positions			Existing Natural Gas Hedge Positions		
Hedge Period	Hedged Volumes (Bbls per Month)	Hedge Price Weighted Average Range ($/Bbl)	As a Percentage of June 2010 Oil Production (2)	Hedged Volumes (MMBtu per Month)	Weighted Average Hedge Price Range ($/MMBtu)	As a Percentage of June 2010 Gas Production (2)
2010						
Q3	690,398	$62.76 - $86.61	42.9%	40,555	$6.00 - $14.00	1.9%
Q4	805,146	$63.98 - $89.53	50.1%	39,445	$7.00 - $14.20	1.8%
2011						
Q1	829,917	$60.20 - $95.11	51.6%	38,139	$7.00 - $17.40	1.8%
Q2	829,696	$60.20 - $95.10	51.6%	36,954	$6.00 - $13.05	1.7%
Q3	829,479	$60.19 - $95.09	51.6%	35,855	$6.00 - $13.65	1.6%
Q4	829,255	$60.19 - $95.08	51.6%	34,554	$7.00 - $14.25	1.6%
2012						
Q1	339,054	$48.17 - $91.55	21.1%	33,381	$7.00 - $15.55	1.5%
Q2	338,850	$48.15 - $91.53	21.1%	32,477	$6.00 - $13.60	1.5%
Q3	338,650	$48.14 - $91.50	21.1%	31,502	$6.00 - $14.45	1.4%
Q4	338,477	$48.12 - $91.49	21.0%	30,640	$7.00 - $13.40	1.4%
2013						
Q1	290,000	$47.67 - $90.21	18.0%			
Q2	290,000	$47.67 - $90.21	18.0%			
Q3	290,000	$47.67 - $90.21	18.0%			
Oct	290,000	$47.67 - $90.21	18.0%			
Nov	190,000	$47.22 - $85.06	11.8%			

(1) As of October 1, 2010

(2) Under Whiting's credit agreement, the Company is allowed to enter into derivative contracts regarding forecasted PDP production volumes for five years as follows: Year 1 – 90%; Years 2 and 3 – 85%; Year 4 – 80% and Year 5 – 75%. The Company has hedged approximately 74.1% of forecasted PDP crude oil production and approximately 2.3% of forecasted PDP natural gas production in 2010. Forecasted PDP volumes were based on independent reserve estimates as of December 31, 2009.

Fixed-Price Marketing Contracts

Existing Natural Gas Marketing Contracts [1]

Period	Contracted Volumes (Mcf per Month)	Weighted Average Contracted Price ($/Mcf)	As a Percentage of June 2010 Production
Q3 2010	742,333	$5.33	34.1%
Q4 2010	825,000	$5.29	37.9%
Q1 2011	779,000	$5.30	35.8%
Q2 2011	786,667	$5.30	36.2%
Q3 2011	772,333	$5.30	35.5%
Q4 2011	772,333	$5.30	35.5%
Q1 2012	577,000	$5.30	26.5%
Q2 2012	461,333	$5.41	21.2%
Q3 2012	465,667	$5.41	21.4%
Q4 2012	398,667	$5.46	18.3%
Q1 2013	360,000	$5.47	16.5%
Q2 2013	364,000	$5.47	16.7%
Q3 2013	368,000	$5.47	16.9%
Q4 2013	368,000	$5.47	16.9%
Q1 2014	330,000	$5.49	15.2%
Q2 2014	333,667	$5.49	15.3%
Q3 2014	337,333	$5.49	15.5%
Q4 2014	337,333	$5.49	15.5%

(1) Under Whiting's credit agreement, the Company is allowed to enter into derivative contracts regarding forecasted PDP production volumes for five years as follows: Year 1 – 90%; Years 2 and 3 – 85%; Year 4 – 80% and Year 5 – 75%. Based on the above schedule, the Company has entered into fixed-price natural gas contracts for the following percentages of forecasted PDP natural gas production: 2010 – 40.2%; 2011 – 45.3%; 2012 – 36.5%; 2013 – 34.4%; 2014 – 35.6%. Forecasted PDP volumes were based on independent reserve estimates as of December 31, 2009.

In Summary

- **Geographically diversified, long-lived reserve base**
  - Five core regions; 13.6 [1] year R/P
  - Grown proved reserves 284% from 71.7 MMBOE at Nov. 2003 IPO to 275.0 MMBOE at 12/31/09
  - Grown production 280% from 17.0 MBOE/D at Nov. 2003 IPO to 64.6 MBOE/D in Q2 2010
- **Multi-year inventory of development, exploitation and exploration projects to drive organic production growth going forward**
  - Drilling inventory of approximately 1,400 gross operated wells based on 3P reserves and an additional approximate 1,000 gross operated wells based on resource potential
- **Additional exploration potential in the Rockies, Permian Basin and Gulf Coast**
  - Significant organic growth potential from drilling programs
  - Continued moderate risk organic growth potential from Postle and North Ward Estes fields
  - Other exploration includes horizontal oil prospects (Williston and Permian Basin)
- **Disciplined acquirer with strong record of accretive acquisitions**
  - 15 acquisitions in 2004 – 2009; 230.7 MMBOE at $8.19 per BOE average acquisition cost
- **Commitment to financial strength**
  - Total Debt to Cap of 22.7% pro forma as of June 30, 2010
- **Proven management and technical team**
  - Average 27 years of experience

(1) R/P ratio based on year-end 2009 proved reserves and total 2009 production.

Adjusted Net Income (1)
(In Thousands)

Reconciliation of Net Income (Loss) Available to Common Shareholders to Adjusted Net Income (Loss) Available to Common Shareholders

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net Income (Loss) Available to Common Shareholders…....	$ 119,926	$ (93,163)	$ 201,147	$ (136,922)
Adjustments Net of Tax:				
Amortization of Deferred Gain on Sale…………………..	(2,489)	(2,740)	(4,811)	(5,334)
Gain on Sale of Properties………………………………	(1,187)	(2,954)	(1,189)	(2,935)
Impairment Expense……………………………………...	2,388	2,312	4,774	5,280
Unrealized Derivative (Gains) Losses……………………	(46,427)	95,955	(65,246)	110,195
Adjusted Net Income (Loss) (1)…………………………………	$ 72,211	(590)	$ 134,675	$ (29,716)
Adjusted Earnings (Loss) Available to Common Shareholders per Share, Basic…………………………………	$ 1.42	$ (0.01)	$ 2.64	$ (0.60)
Adjusted Earnings (Loss) Available to Common Shareholders per Share, Diluted………………………………	$ 1.31	$ (0.01)	$ 2.46	$ (0.60)

(1) Adjusted Net Income (Loss) Available to Common Shareholders is a non-GAAP financial measure. Management believes it provides useful information to investors for analysis of Whiting's fundamental business on a recurring basis. In addition, management believes that Adjusted Net Income (Loss) Available to Common Shareholders is widely used by professional research analysts and others in valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted Net Income Available for Common Shareholders should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, cash flow or liquidity measures under GAAP and may not be comparable to other similarly titled measures of other companies.

Discretionary Cash Flow (1)

Reconciliation of Net Cash Provided by Operating Activities to Discretionary Cash Flow (In Thousands)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Net cash provided by operating activities……..	$ 243,586	$ 110,067
Exploration………………………………………....	10,652	6,178
Exploratory dry hole costs……………………….	(587)	(2)
Changes in working capital………………………..	(20,097)	(6,497)
Preferred stock dividends paid………………….	(5,391)	-
Discretionary cash flow……………………..	$ 228,163	$ 109,746

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net cash provided by operating activities……..	$ 440,133	$ 145,009
Exploration………………………………………....	19,715	18,811
Exploratory dry hole costs……………………….	(2,597)	(54)
Changes in working capital………………………..	(3,752)	17,876
Preferred stock dividends paid………………….	(10,781)	-
Discretionary cash flow……………………..	$ 442,718	$ 181,642

(1) Discretionary cash flow is computed as net income plus exploration and impairment costs, depreciation, depletion and amortization, deferred income taxes, non-cash interest costs, non-cash compensation plan charges, property impairments, exploratory dry hole costs, gain/loss on mark-to-market derivatives and other non-current items less the gain on sale of properties and amortization of deferred gain on sale and preferred stock dividends paid. The non-GAAP measure of discretionary cash flow is presented because management believes it provides useful information to investors for analysis of the Company's ability to internally fund acquisitions, exploration and development. Discretionary cash flow should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, cash flow or liquidity measures under GAAP and may not be comparable to other similarly titled measures of other companies.

Whiting Provides Answers to Recent Investor and Analyst Questions (1)(2)

WHITING

Bakken and Three Forks Reservoir and Geology

Q1 – What is the oil in place per section for Sanish (Bakken)?

A1 – It varies across the field and is difficult to calculate in this complex reservoir. We estimate that there are approximately 8-11 million barrels of black oil per section. We hold interests in 170 sections in the Sanish field.

Q2 – What is the ultimate recovery for Sanish (Bakken)?

A2 – We estimate the expected recovery to be 600-900,000 barrels of black oil per section or about 8% of the original oil in place (OOIP). Note that we are drilling 2 wells on each 1,280-acre (2 sections) unit.

Q3 – What is the oil in place per section for Sanish (Three Forks)?

A3 – We have less geologic and reservoir data on the Three Forks since we are very early in the development. OOIP will vary across the field and is difficult to calculate in this complex reservoir. We estimate there to be 4-6 million barrels of black oil per section.

Q4 – What is the ultimate recovery for Sanish (Three Forks)?

A4 – We estimate the expected recovery to be 350-500,000 barrels of black oil per section or about 8% of OOIP. Again, we plan to drill 2 wells per 1,280-acre (2 sections) unit.

Q5 – How does the geology compare across your project areas in terms of porosity, thickness, and pressure gradients? Sanish, Lewis & Clark, McKenzie/Williams Counties.

A5 – In each project area it varies to some extent as you can see on our slide titled "Middle Bakken Induced Fractures" where the Middle Bakken exists over Sanish but pinches out and is almost non-existent over at Parshall. Permeability varies both in the matrix and due to the intensity of natural fracturing. Comparing prospect area to prospect area, there are wide variations in the geology. For example, the Middle Bakken has pinched out and does not exist at Lewis & Clark.

(1) The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

(2) Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

Bakken and Three Forks Reservoir and Geology (Continued)

Q6 – What led you to the Lewis & Clark extension?

A6 – Regional mapping; taking what we learned at Sanish and Parshall and applying that to other parts of the basin.

Q7 – How does the Three Forks play vary between the Sanish and Lewis & Clark areas?

A7 – They are geologically very similar. The Three Forks may be slightly tighter at Lewis & Clark.

Q8 – Is the Sanish Sand required to make a productive well in the extensional Lewis & Clark area?

A8 – No, we had very little Sanish Sand in the Federal 32-4.

Q9 – Are there any specific catalysts that would encourage you to step up drilling activity in the Lewis & Clark area?

A9 – If we consistently drill and complete wells that generate initial results indicating ROI's of at least 3:1 we will step up activity.

Q10 – Are the Scallion Limestone and Lodgepole formations valid resource targets?

A10 – Yes, in various parts of the basin.

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(Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

WHITING

Bakken Well Design and Completion

Q11 – Why sliding sleeve versus perf and plug?

A11 – It is mechanically simpler, less moving parts. We can complete wells through the winter. On a sliding sleeve job, we can complete the fracture stimulation in about 24 hours.

Q12 – At Sanish, where should the horizontal well be landed within the Middle Bakken target zone to achieve the best production?

A12 – See slide titled "Middle Bakken Induced Fractures." It is our opinion that it is in the "B" zone of the Middle Bakken.

Q13 – Does the azimuth of the lateral well matter in meeting stimulation and reservoir drainage objectives?

A13 – Yes, we believe you need to drill in a direction that is approximately perpendicular to the maximum principal stress. This is 55 degrees northeast. See our slide titled "Fully Developed Bakken and Three Forks Horizontal Wells in Sanish Field Area."

Q14 – Do the natural fractures impact fracture initiation?

A14 – Probably, we see slightly lower fracturing pressure on the east side of Sanish field where we know the natural fracturing intensity is higher.

Q15 – How might your completions vary by area and what are the geologic factors that drive your approach?

A15 – If the rock is tighter and contains fewer natural fractures, we will pump more stages.

Q16 – Why white sand vs. ceramics in the Sanish field?

A16 – Our engineering evaluation indicates that we do not need ceramics to maintain open fractures in Sanish.

Q17 – A few industry studies suggest that using ceramic proppants can increase EUR. Have you tested this and what are your thoughts on this matter?

A17 – The pressure pumping companies sell ceramics for about 5 times the amount of sand, so they are going to push ceramics. This is difficult to test so you may not know the answer for years.

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(Continued) Whiting Provides Answers to Recent Investor and Analyst Questions (1)(2)

WHITING

Bakken Development Planning and Well Costs

Q18 – How many un-drilled locations at year-end 2009 were included in your reserve report for each of the following areas: Sanish/Parshall (Bakken); Sanish/Parshall (Three Forks); and Lewis & Clark (Three Forks)?

A18 – Sanish/Parshall (Bakken): 75 locations in PUD, 30 locations in Probable, 41 locations in Possible for a total 3P of 146 locations; Sanish/Parshall (Three Forks): 0 PUD, 1 well location in Probable, 224 locations in Possible for a total 3P of 225 locations; Lewis & Clark (Three Forks): No locations in 3P. Approximately 379 locations in Resource.

Q19 – Can you provide some detail on the 1,400 (and 1,000) well drilling inventory as of December 31, 2009?

A19 –

ESTIMATED TOTAL 3P LOCATIONS

Area	Gross	Net
Sanish Field Area	273	147
Parshall Field	98	21
Sulphur Creek Field	227	150
Northern Rockies	55	31
Central Rockies	74	46
Mid-Continent	66	56
Gulf Coast	137	82
Permian	544	189
Total	1,474	722

ESTIMATED TOTAL RESOURCE LOCATIONS

Area	Gross	Net
Lewis & Clark	379	166
Sanish Field Area	79	40
Other Williston	77	37
Sulphur Creek	307	175
Other Areas	229	204
Total	1,071	622

(1) The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

(2) Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information."

(Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

Bakken Development Planning and Well Costs (Continued)

Q20 – What is the timing of the 13 Lewis & Clark wells in 2010?

A20 – We drilled three in Q2 and are planning to drill 5 wells in Q3 and 5 in Q4.

Q21 – What type of pressures are you experiencing on drilling and completion costs?

A21 – As the rig count has increased in North Dakota we have seen the cost of our frac jobs increase from its low of last year. This is caused by two factors. We are pumping more stages and we have had increases in labor costs passed through to us. From 2009's low, our frac cost has increased on the order of 20% – 30%. The majority of the drilling rigs we have in North Dakota are on 6 month contracts with an option to extend for an additional 6 months. In some cases we have also tied the day rate to NYMEX oil prices. These factors have helped keep the drilling economics in line with our expectations.

Q22 – What are your current spud to total depth and spud to spud times? How much more efficiency is possible?

A22 – Across our program, for winter / spring 2009-10, spud to TD was averaging 24 days. Spud to spud average was 40.5 days. We have drilled two wells spud to TD in just 15 days. For these wells, spud to rig release was about 25 days. At Sanish, for 40 wells drilled from January 1 through July 20, 2010, our average spud to TD averaged 21.2 days. Our spud to spud is averaging 39 days. We still think there are efficiencies to be gained and that we can eliminate another 2 to 4 days out of the process.

[1] The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

(Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

Bakken Development Planning and Well Costs (Continued)

Q23 – How long does it take to complete a well and what types of efficiencies are possible with multi-pad drilling?

A23 – We have our wells completed within about three weeks of rig release. We build the battery, lay the oil gathering and gas gathering lines during that three-week period. Consequently, once the well is frac'd we can go down the sales line with the production. We see no significant efficiency to pad drilling. You delay the production from the first wells drilled until you finish drilling all of the wells on the pad. You can save on rig moves, but you may cause mechanical issues with more complicated well designs. Further, production bulges caused by multiple completions over a limited period of time may cause marketing/product sales issues.

Q24 – At present, Whiting is planning 2.5 Middle Bakken wells per 1,280. Are you planning to conduct any further testing beyond that to examine drainage patterns?

A24 – Yes, we have an active reservoir surveillance program going on in the field. We collect pressure data, monitor production and monitor offset wells when we perform fracture stimulations. We have also installed a permanent micro seismic array in the field to monitor and map every frac we perform across the entire field.

Q25 – With your expertise in EOR, is the Middle Bakken prospective for CO_2 flooding and when might you consider testing that, if so?

A25 – We have evaluated this option. The initial issue is CO_2. There is not a source with sufficient capacity in the Williston Basin. However, man made CO_2 projects are being designed and may be available in 2-4 years. Natural fractures may make the CO_2 move through the reservoir so fast that it makes a CO_2 project risky. In summary, it is unlikely.

Q26 – What type of primary/secondary recovery could be expected?

A26 – Primary recovery 8% - 10%, secondary recovery currently questionable.

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(Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

Bakken Well Productivity

Q27 – Could you review how you measure 24-hour and 30-day IP rates?

A27 – After the frac job, we let the well sit for approximately 3 days to allow the gel to break down and the sand to keep the fractures open. We bring the well back at a fairly aggressive rate to ensure we get the balls off seat and get the entire horizontal lateral producing. After about 48 hours of flow back, we initiate the IP test and put the well on a 40/64ths choke and monitor the production for a 24-hour period. Production is measured by strapping the production tanks that are on location. We measure and internally report our production for every well we operate on a daily basis (company wide). The 30-day rate is just that, what the well averages over the first 30 days of production.

Q28 – How strong of an indicator is the 30-day rate on EUR?

A28 – We believe it is an early indicator. Our technical team has developed a rough correlation between 30-day rates and EUR's and this is reflected in the typical Bakken production profiles in our slide show.

Q29 – As investors, what variables should we comprehend in our analysis when comparing one company's 30-day rate versus another's?

A29 – The 30-day rate is an early indicator but the 60 and 90 day rates are even better indicators.

Q30 – What are the important milestones when attempting to measure a well's potential deliverability (30-day rates, well performance when on pump)?

A30 – All of the above are indicators but 60 and 90 day rates are perhaps the best for early on scoping as this starts to define the hyperbolic curve the well may follow. Tubing pressure is also a good indicator as well as cumulative production at the time the well goes on pump.

[1] The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

(Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1][2]

WHITING

Portfolio/EOR

Q31 – In the 2009 year-end reserve report, what assumptions were made for North Ward Estes recovery (Proved, 2P and 3P) and for Postle (Proved, 2P and 3P)?

A31 – Estimated remaining reserves at North Ward Estes are based on section by section geologic and reservoir engineering analysis and vary throughout the field depending on reservoir quality and our development plans. In general, the resulting EUR's indicate tertiary recoveries of 5-6% in the Proved category, up to 7-8% in the Probable category and 10-11% or more in the Possible category. Our estimated remaining reserves at Postle are also based on detailed geologic and engineering analysis on an injection pattern level and vary throughout the field. In general, the resulting EUR's indicate tertiary recoveries of 12-16% or more, all in the proved category due to the mature state of development for most of the Postle field.

Q32 – In terms of portfolio management, what are the key drivers behind your capital allocation process? The returns in the Bakken are different than EOR, but EOR is a bit more resilient through the cycles.

A32 – You are correct. Generally, drilling provides higher IRR's and EOR projects have a greater assurance of reserve additions. We are fortunate to have a mixture of both in Whiting's inventory of projects. Drilling projects begin to decline when drilling activity peaks. EOR projects begin to incline about a year after project installation and commencement of H_2O and CO_2 injection. After production peaks on an EOR project production can plateau and remain relatively flat for several years before beginning to decline. This is caused by the pressure maintenance of the H_2O and CO_2. This plateau production may provide cash flow for many years to fund additional exploration and development drilling projects for the company.

Q33 – What is your capital for all non-Bakken and non-EOR projects?

A33 – See our slide titled "2010 Exploration and Development Budget." The projects on that list not related to our Bakken, Three Forks and EOR projects total $183MM.

[1] The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

[2] Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.