



Whiting Petroleum Corporation



Corporate Information
June 2008

Forward-Looking Statement Disclosure, Reserve Information and Non-GAAP Measures

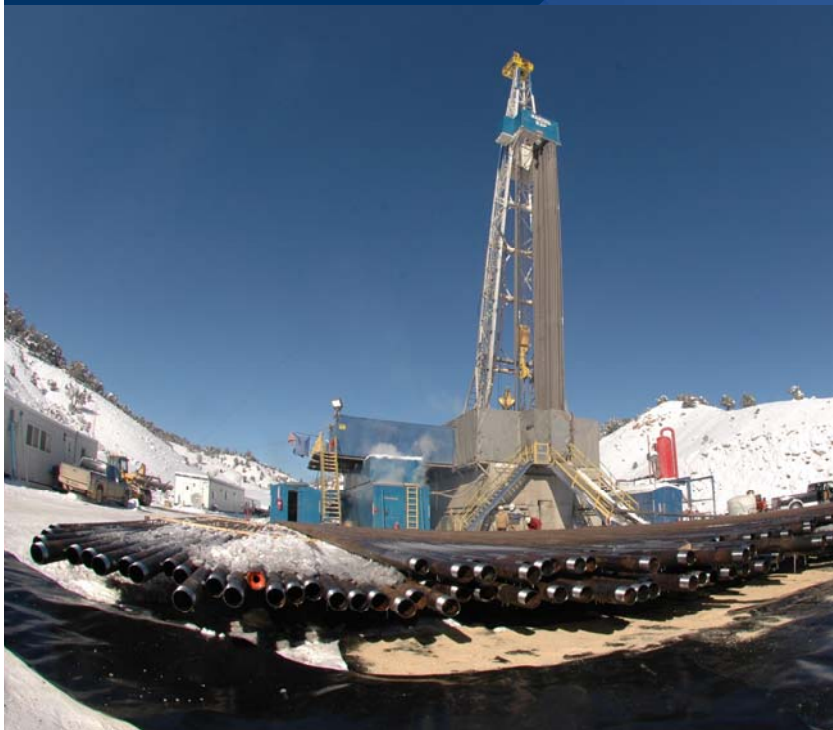


This presentation includes forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact included in this presentation are forward-looking statements. 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, reserves, technology, financial strategy, realized oil and natural gas prices, production, the Company's ability to successfully integrate acquired properties, unforeseen underperformance of or liabilities associated with acquired properties, drilling of wells, uncertainty regarding the Company's future operating results and plans, objectives, expectations and intentions and other factors described under the caption "Risk Factors" in the Company's Form 10-K for the year ended December 31, 2007. For additional information, please refer to the Company's Form 10-Q for the three months ended March 31, 2008.

The SEC permits oil and gas companies to disclose in their filings with the SEC only proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Whiting uses in this presentation the terms "probable" and "possible" reserves, which SEC guidelines prohibit in filings of U.S. registrants. Probable reserves are unproved reserves that are more likely than not to be recoverable. Possible reserves are unproved reserves that are less likely to be recoverable 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. 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 Discretionary Cash Flow, which is a non-GAAP measure that the Company believes is helpful in evaluating the performance of its business. A reconciliation of Discretionary Cash Flow to the relevant GAAP measure can be found at the end of the presentation.

Company Overview



Drilling the Boies B-19N-N3 discovery well in the north-central Piceance Basin, Rio Blanco County, Colorado.
IP: 2,486 Mcf/d

Market Capitalization¹	\$4.4 B
Long-term Debt²	\$910 MM
Fully Diluted Shares	42.4 MM
Debt/Total Cap²	36.9%
Proved reserves³	250.8 MMBOE
% Oil	78%
RP ratio⁴	16.4 years
March 2008 Production	41.8 MBOE/d

- 1 Assumes a \$103.52 share price (closing price as of June 6, 2008) on 42,581,316 shares.
- 2 Principal amount of debt outstanding at March 31, 2008: \$290 MM bank debt plus \$620 MM of Sr. Sub. Notes.
- 3 Whiting reserves at December 31, 2007 based on independent engineering.
- 4 Based on March 2008 production.

Net Income and Discretionary Cash Flow for the Three Months Ending March 31, 2008 and 2007



	Three Months Ended	
	<u>3/31/08</u>	<u>3/31/07</u>
<i>(In millions, except per share data)</i>		
Net Income	\$ 62.3	\$ 10.7
Net Income Per Share	\$ 1.47	\$ 0.29
Discretionary Cash Flow	\$ 161.4	\$ 74.1

Please refer to slide #46 for a Reconciliation of Net Cash Provided Operating Activities to Discretionary Cash Flow.

Earnings Growth



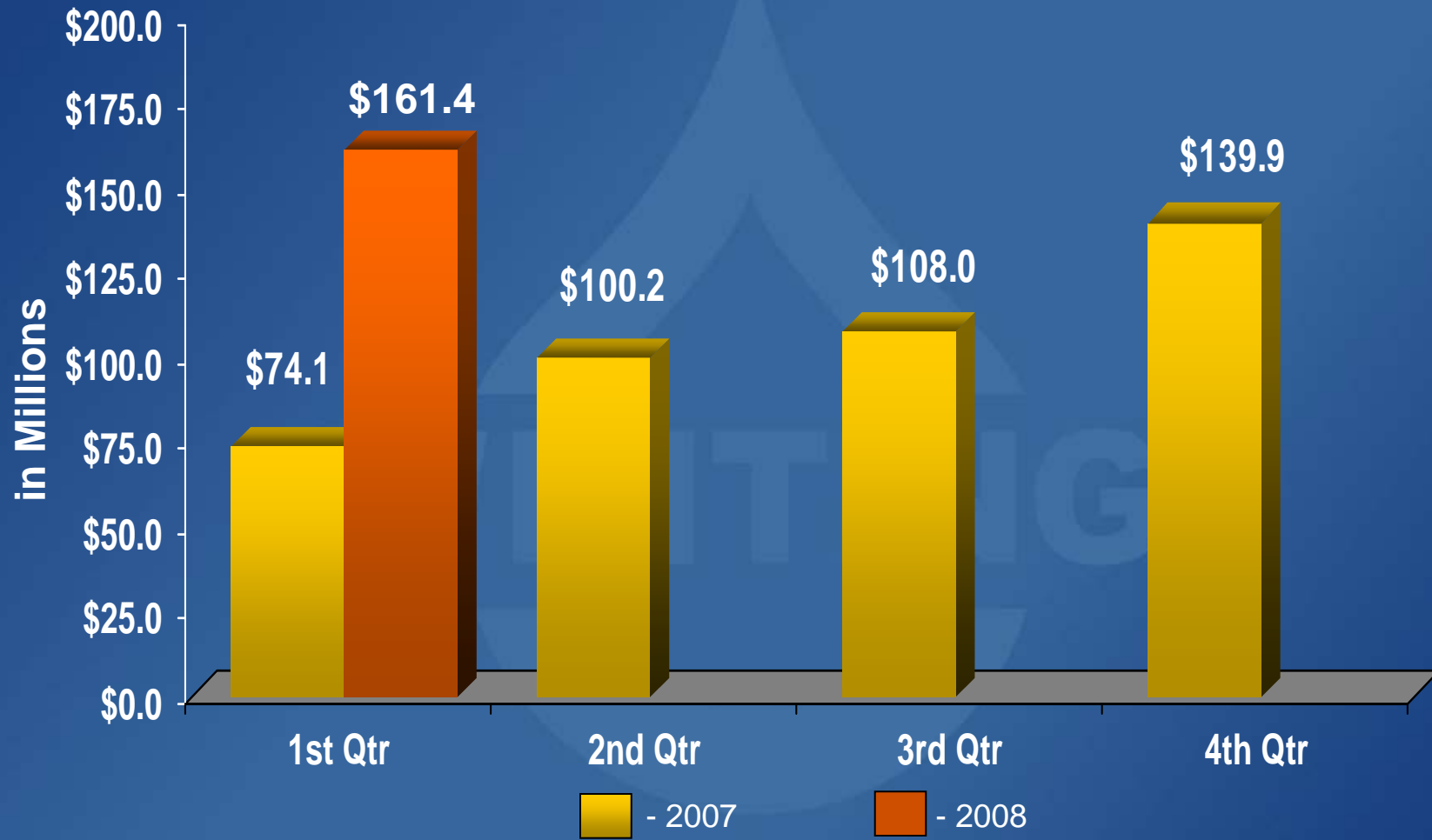
Net Income Per Diluted Share Per Quarter



Growing Levels of Cash Flow

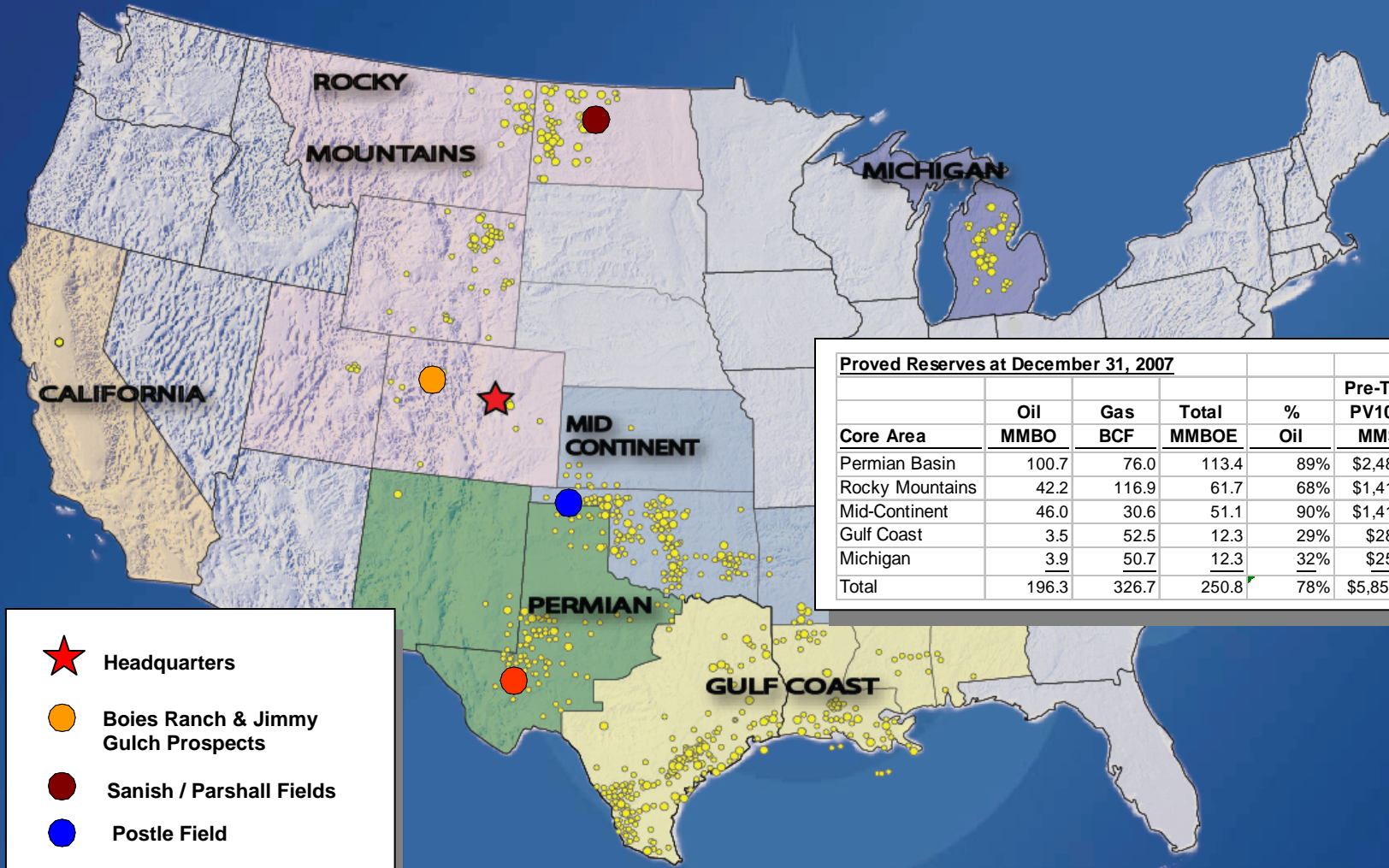


Discretionary Cash Flow Per Quarter⁽¹⁾



(1) Please refer to Slide #46 and #47 – Reconciliation of Net Cash Provided by Operating Activities.

Map of Operations



- ★ Headquarters
- Boies Ranch & Jimmy Gulch Prospects
- Sanish / Parshall Fields
- Postle Field
- North Ward Estes Field
- Other Whiting Properties

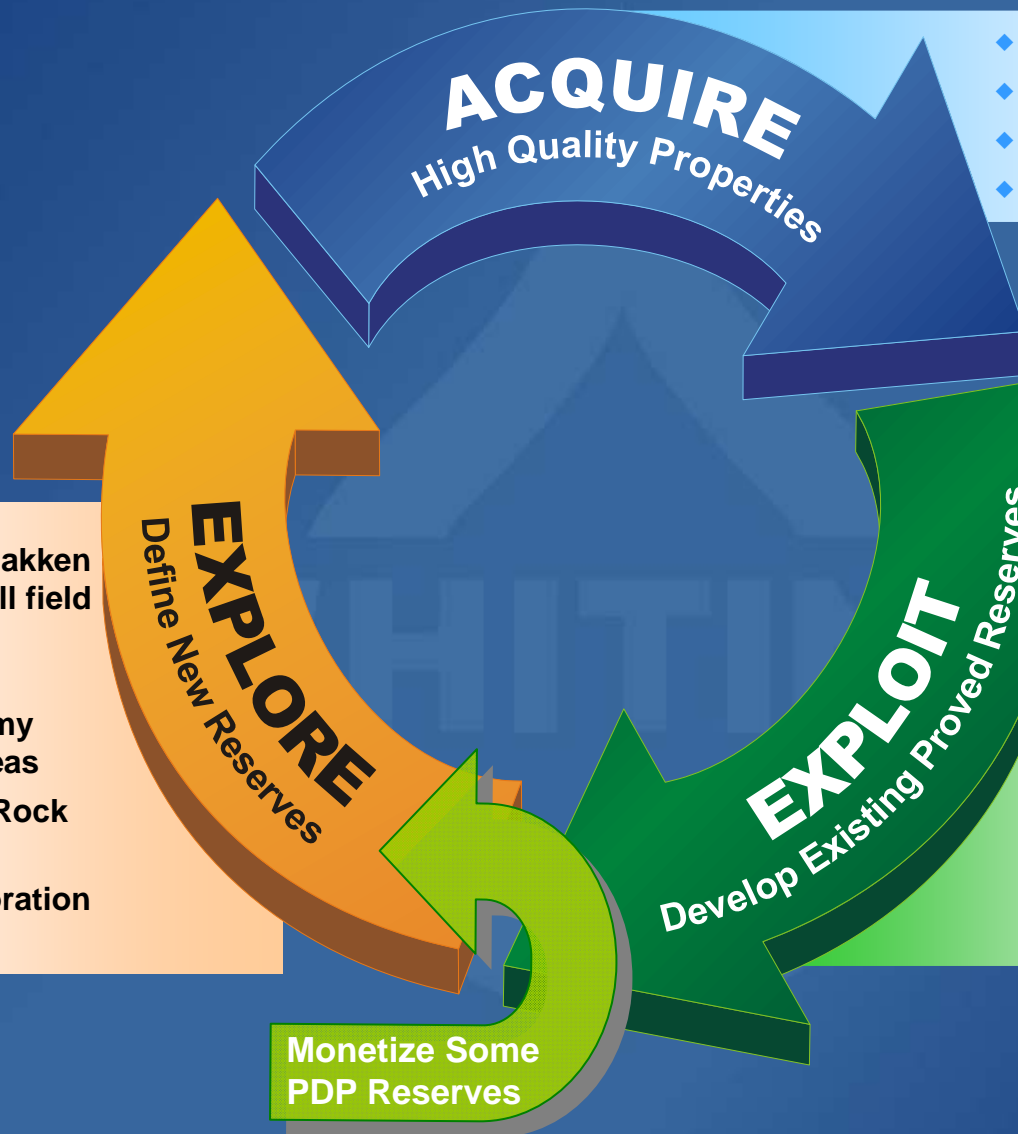
	Oil	Gas	Total	%	Pre-Tax	March
Core Area	MMBO	BCF	MMBOE	Oil	PV10% MM\$	Net Prod MBOE/D
Permian Basin	100.7	76.0	113.4	89%	\$2,483.0	11.0
Rocky Mountains	42.2	116.9	61.7	68%	\$1,418.0	15.4
Mid-Continent	46.0	30.6	51.1	90%	\$1,418.0	7.4
Gulf Coast	3.5	52.5	12.3	29%	\$284.7	4.2
Michigan	3.9	50.7	12.3	32%	\$254.6	3.8
Total	196.3	326.7	250.8	78%	\$5,858.3	41.8

Whiting Petroleum Corporation Highlights



- 1. Geographically diversified, long-lived reserve base**
- 2. Disciplined acquiror with strong record of accretive acquisitions, including the Postle and North Ward Estes fields**
- 3. Multi-year inventory of development and exploitation projects to drive organic production growth going forward**
 - A. Moderate risk organic growth potential from Postle and North Ward Estes fields: production growth and conversion of 94.4 MMBOE of probable and possible reserves**
 - B. Significant organic growth potential from drilling programs in the Williston, Piceance and Uinta Basins**
- 4. Additional exploration potential in the Rockies, Permian Basin and Gulf Coast**
- 5. Commitment to financial strength plus a proven management and technical/employee team**

Our Formula for Success



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

- ◆ Williston Basin – Bakken Sanish and Parshall field areas
- ◆ Piceance Basin – Boies Ranch / Jimmy Gulch prospect areas
- ◆ Uinta Basin – Flat Rock field
- ◆ New Rockies exploration areas

- ◆ Permian Basin – North Ward Estes
- ◆ Williston Basin – North Elkhorn Ranch field
- ◆ Anadarko Basin – Postle field
- ◆ Green River Basin – Siberia Ridge field, Anderson Canyon field

Post-IPO Acquisitions 2004 – 2006 ⁽¹⁾



	Closing Date(s)	Purchase Price	Reserves (MMBOE)	Percent Oil	Percent Developed	Proved Reserve Acquisition Cost (\$/BOE)
North Ward Estes Field (Celero)	10/4/05	\$459.2	82.1	94%	36%	\$5.58
Postle Field (Celero)	8/4/05	343.0	40.3	94%	57%	8.52
Permian Basin Properties	9/23/04	345.0	41.9	82%	59%	8.22
Equity Oil Company	7/20/04	72.6	14.6	68%	79%	4.98
Green River Basin	3/31/05	65.0	8.4	2%	68%	7.74
Colorado/Wyoming Properties	8/13/04	44.2	6.6	46%	82%	6.66
Wyoming/Utah Properties	9/30/04	35.0	5.1	65%	92%	6.84
Institutional Partnerships	6/23/05	30.5	2.9	62%	99%	10.52
Michigan	8/15/06	26.0	1.4	50%	99%	18.55
Louisiana/Texas Properties	8/16/04	19.3	2.0	9%	63%	9.66
Mississippi/Permian	11/3/04 & 12/31/04	19.0	2.4	87%	62%	7.92
TOTALS		\$1,458.8	207.7	82%	53%	\$7.02 ⁽³⁾

Whiting has Shown a Major Increase in Its Reserve Base Through Twelve Acquisitions in its Core Areas ⁽²⁾

(1) All statistics as of effective date of acquisitions.

(2) 207.7 MMBOE represents 83% of 250.8 MMBOE of proved reserves at December 31, 2007.

(3) \$1.17 per mcfe.

Pre-Tax PV10%



<u>Core Area</u>	<u>Proved Reserves</u>				<u>Pre-Tax PV10% Value⁽¹⁾⁽³⁾ (In millions)</u>	<u>March 2008 Average Daily Production (MBOE/d)</u>
	<u>Oil (MMbbl)</u>	<u>Natural Gas (Bcf)</u>	<u>Total (MMBOE)</u>	<u>% Oil</u>		
Permian Basin	100.7	76.0	113.4	89%	\$ 2,483.0	11.0
Rocky Mountains	42.2	116.9	61.7	68%	1,418.0	15.4
Mid-Continent	46.0	30.6	51.1	90%	1,418.0	7.4
Gulf Coast	3.5	52.5	12.3	29%	284.7	4.2
Michigan	3.9	50.7	12.3	32%	254.6	3.8
Total	<u>196.3</u>	<u>326.7</u>	<u>250.8</u>	<u>78%</u>	<u>\$ 5,858.3⁽²⁾⁽³⁾</u>	<u>41.8</u>
Discounted Future Income Taxes					<u>(1,846.6)</u>	
Standardized Measure of Discounted Future Net Cash Flows					<u>\$ 4,011.7⁽²⁾⁽³⁾</u>	

(1) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. We believe pre-tax PV10% is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV10% and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

(2) At year-end 2006, these values were \$3,352.2 million and \$2,392.2 million, respectively, based on Dec. 31, 2006 prices: NYMEX \$61.05/Bbl and \$5.52/MMbtu.

(3) Based on Dec. 31, 2007 prices: NYMEX \$96.00/Bbl and \$7.10/MMbtu. The year-end 2007 PV10% value of \$5,858.3 million represents a 75% increase over the \$3,352.2 million at year-end 2006.

Reserve Components Year-End 2007 vs. Year-End 2006 ⁽¹⁾



	As of 12/31/07		As of 12/31/06		Change MMBOE
	MMBOE	% of Total	MMBOE	% of Total	
PDP	130.4	52%	120.6	49%	9.9
PDNP	36.4	15%	39.7	16%	(3.3)
PUD	84.0	33%	87.9	35%	(3.9)
Total Proved	250.8	100%	248.2	100%	2.7
Proved	250.8	51%	248.2	66%	2.7
Probable	87.0	17%	60.2	16%	26.8
Possible	155.7	32%	68.9	18%	86.8
Total 3P	493.5	100%	377.3	100%	116.3

(1) Based on independent engineering by Cawley Gillespie & Associates, Inc. at December 31, 2007.

Whiting Net Asset Value Calculation at December 31, 2007 (1) (2) (3)



	MBO	MBNGL	Oil & NGL MBO	MMCF	MBOE	PV10, M\$
PVPD	88,719	8,070	96,789	201,410	130,357	\$ 3,290,985
PVBP	15,590	1,469	17,059	29,664	22,003	\$ 421,301
PVNP	11,866	1,578	13,444	5,956	14,436	\$ 413,466
PVUD	59,937	9,090	69,027	89,712	83,978	\$ 1,732,532
Total Proved	176,112	20,207	196,319	326,742	250,774	\$ 5,858,284
Total Probable	48,417	5,411	53,828	199,220	87,031	\$ 1,783,722
Total Possible	85,220	10,239	95,459	361,427	155,696	\$ 3,052,821
Total 3P Reserves	309,749	35,857	345,606	887,389	493,501	\$10,694,827
Book Value Undeveloped Acreage						\$ 38,000
Total Reserves and Acreage						\$10,732,827
Working Capital Deficit, M\$						\$ (92,497)
Bank Debt, M\$						\$ (250,000)
Bond Debt, M\$						\$ (620,000)
Terminating Value of Production Participation Plan, M\$						\$ (106,600)
Asset Retirement Obligation, M\$						\$ (35,883)
Tax Sharing Liability, M\$						\$ (23,070)
Other Long-term Liabilities, M\$						\$ (2,314)
Net Asset Value, M\$						\$ 9,602,463
Shares Issued at 12/31/07						42,480,497
Net Asset Value Per Share						\$ 226.04

(1) Reserve estimates based on independent engineering by Cawley Gillespie & Associates, Inc. at December 31, 2007.

(2) Based on December 31, 2007 NYMEX prices of \$96.00/Bbl and \$7.10/MMbtu.

(3) Net asset value is a non-GAAP financial measure as defined by the SEC. We believe investors may utilize our net asset value as a basis for comparison of the relative size and value of our reserves to other companies. However, net asset value is not a substitute for standardized GAAP measures. Our net asset value does not purport to present the fair value of our oil and natural gas reserves. See slide #1 for disclosures regarding "probable" and "possible" reserves.

Finding Costs

(In Thousands)



	2003	2004	2005	2006	2007	Acq. & Dev. Cost Over Five Years (2003 – 2007)
Proved Acquisitions	\$ 11,823	\$ 525,563	\$ 906,208	\$ 29,778	\$ 8,128	\$ 1,481,500
Unproved Acquisitions	\$ 242	\$ 4,401	\$ 16,124	\$ 38,628	\$ 13,598	\$ 72,993
Development Cost	\$ 40,423	\$ 74,476	\$ 215,162	\$ 408,828	\$ 506,057	\$ 1,244,946
Exploration Cost	\$ 3,186	\$ 9,739	\$ 22,532	\$ 81,877	\$ 56,741	\$ 174,075
Total Cost Incurred	\$ <u>55,674</u>	\$ <u>614,179</u>	\$ <u>1,160,026</u>	\$ <u>559,111</u>	\$ <u>584,524</u>	\$ 2,973,514
Acquisition Reserves						
Acquisition Reserves – Oil (MBbls)	822	52,288	115,738	670	691	170,209
Acquisition Reserves – Gas (MMCF)	3,996	114,715	101,082	4,009	-	223,802
Total Acquisition Reserves (MBOE)	<u>1,488</u>	<u>71,407</u>	<u>132,585</u>	<u>1,338</u>	<u>691</u>	<u>207,509</u>
Development Reserves						
Development Reserves – Oil (MBbls)	2,327	5,175	1,957	4,125	10,973	24,557
Development Reserves – Gas (MMCF)	17,097	29,133	21,068	19,362	40,936	127,596
Total Development Reserves (MBOE)	<u>5,177</u>	<u>10,031</u>	<u>5,468</u>	<u>7,352</u>	<u>17,796</u>	<u>45,824</u>
Revisions						
Reserve Revisions – Oil (MBbls)	4,627	(854)	950	2,053	392	7,168
Reserve Revisions – Gas (MMCF)	(4,474)	(9,862)	(45,322)	(57,780)	8,079	(109,359)
Total Reserve Revisions (MBOE)	<u>3,881</u>	<u>(2,498)</u>	<u>(6,604)</u>	<u>(7,577)</u>	<u>1,739</u>	<u>(11,059)</u>
Cost Per BOE to Acquire (in Dollars)	\$ <u>7.95</u>	\$ <u>7.36</u>	\$ <u>6.83</u>	\$ <u>22.25</u>	\$ <u>11.76</u>	\$ <u>7.14</u>
Cost Per BOE to Develop (in Dollars)	\$ <u>4.84</u>	\$ <u>11.76</u>	\$ <u>-</u>	\$ <u>-</u>	\$ <u>29.51</u>	\$ <u>42.92</u>
All-In Finding Cost Per BOE (in Dollars)	\$ <u>5.28</u>	\$ <u>7.78</u>	\$ <u>8.82</u>	\$ <u>502.27</u>	\$ <u>28.90</u>	\$ <u>12.27</u>
Future Proved Development Cost						\$ 1,186,800
All-In Rate with Future Development Cost						\$ <u>17.17</u>
Probable and Possible Reserves (MBOE)						242,700
Probable and Possible Capital Expenditures						\$ 1,762,500
All-In Rate With Future Development Cost and Prob. And Poss.						\$ <u>12.21</u>

Reserve Replacement

(In MMBOE)



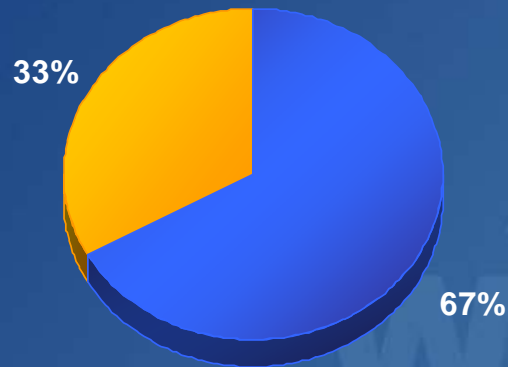
	<u>2007</u>	<u>Five-Year (2003-2007) Replacement</u>
Acquisition Reserves	0.7	207.5
Development Reserves	17.8	45.8
Reserve Revisions	<u>1.7</u>	<u>(11.1)</u>
Total New Reserves	<u><u>20.2</u></u>	<u><u>242.3</u></u>
Production	14.7	56.0
Reserve Replacement (%)	138%	433%

Reserve & Production Profiles



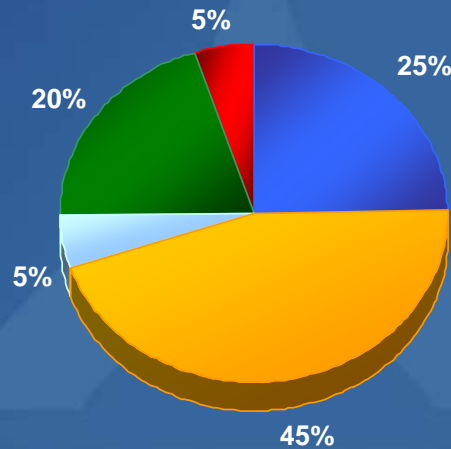
Proved Reserves

As of Dec. 31, 2007
250.8 MMBOE



- Developed
- Undeveloped

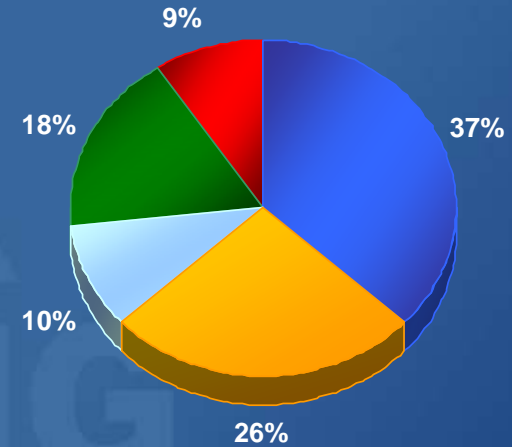
Proved Reserves By Core Area



- Rocky Mountains
- Permian Basin
- Gulf Coast
- Mid-Continent
- Michigan

Daily Production By Core Area

March 2008
41.8 MBOE/d

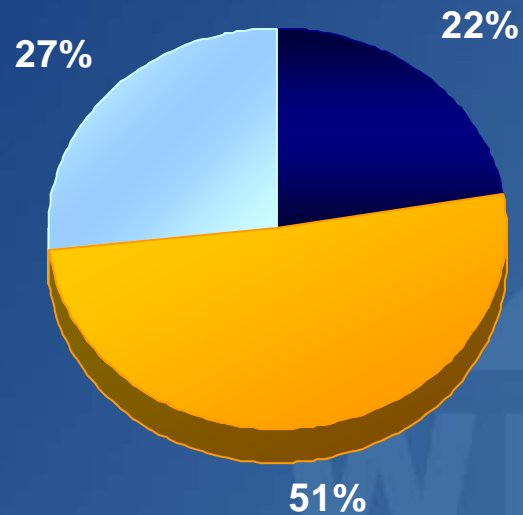


Based on March 2008 Production, Whiting Has a 16.4 Year R/P Ratio

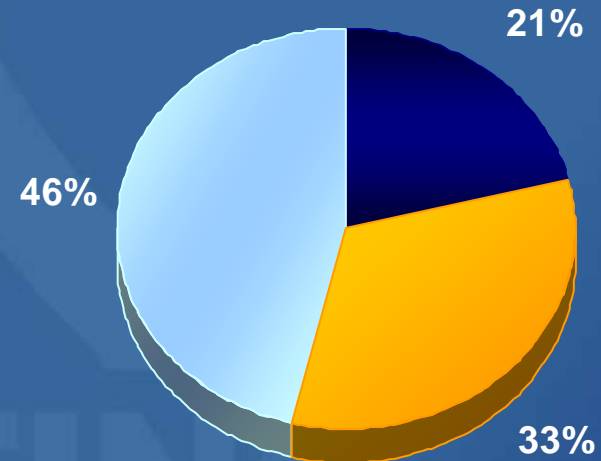
2007 vs. 2008 Exploration & Development Expenditures By Reserve Category



2007 – \$556.6 MM Actual



2008 – \$765 MM Budget

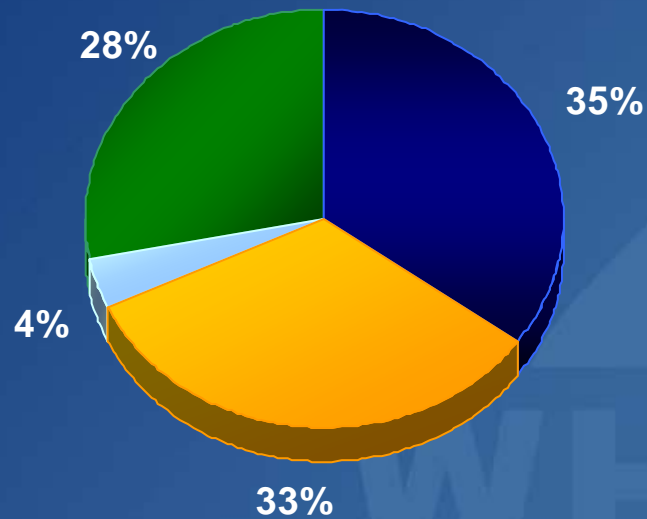


- Proved
- CO₂ Recovery Projects (Proved)
- Non-Proved

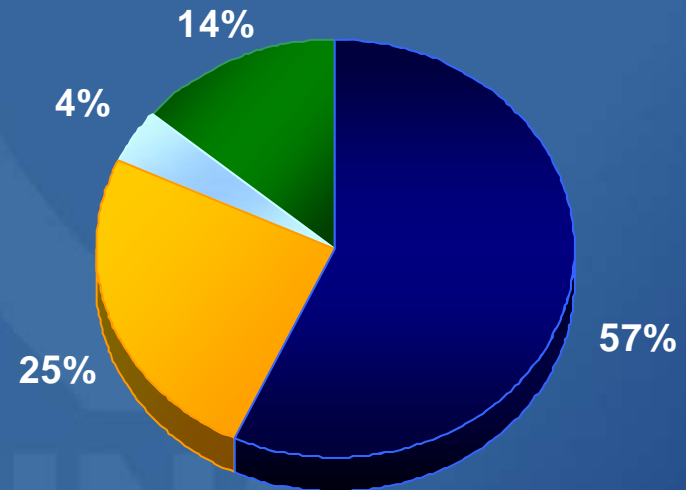
2007 vs. 2008 Exploration & Development Expenditures By Core Area



2007 – \$556.6 MM Actual



2008 – \$765 MM Budget



- Rocky Mountains
- Permian Basin
- Gulf Coast
- Mid-Continent/Michigan

Total Capitalization

(\$ in thousands)



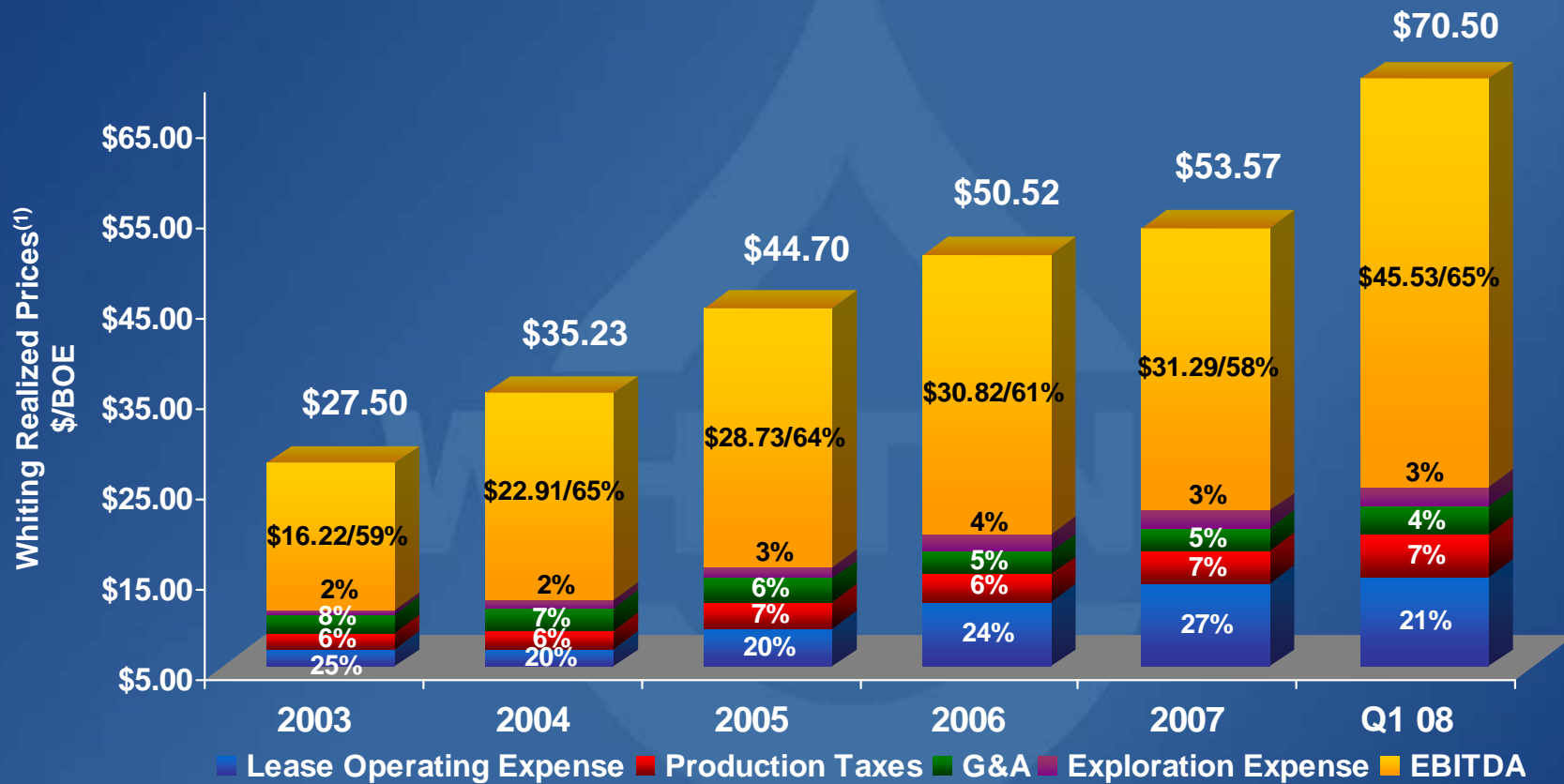
As of March 31, 2008

Cash and Cash Equivalents	<u>\$ 6,730</u>
Long-Term Debt:	
Credit Agreement	\$ 290,000
Senior Subordinated Notes	<u>619,998</u>
Total Long-Term Debt	<u>\$ 909,998</u>
Stockholders' Equity	<u>1,553,936</u>
Total Capitalization	<u>\$ 2,463,934</u>
Total Debt / Capitalization	36.9%

Consistently Strong Margins

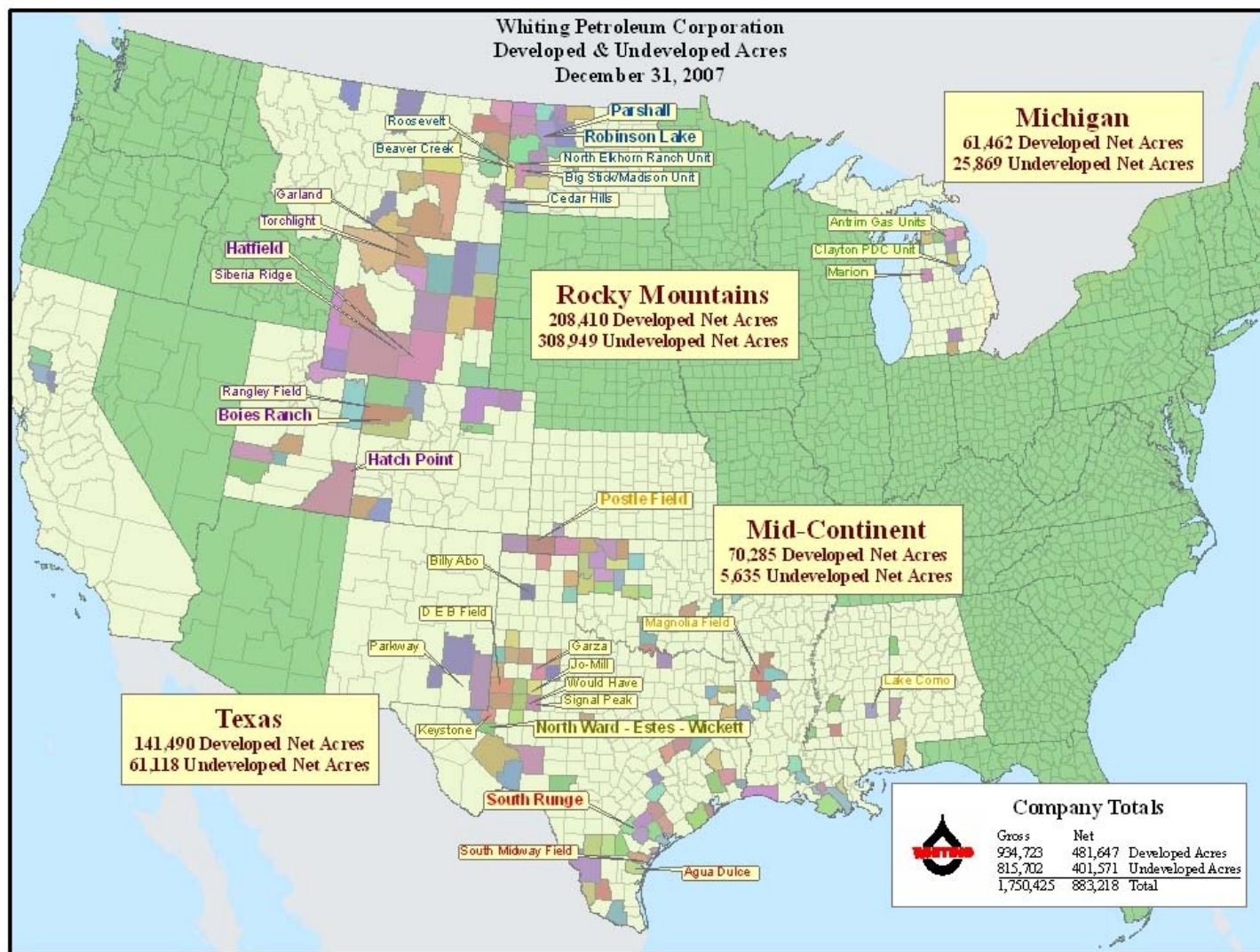


Consistently Delivering Strong EBITDA Margins ⁽¹⁾

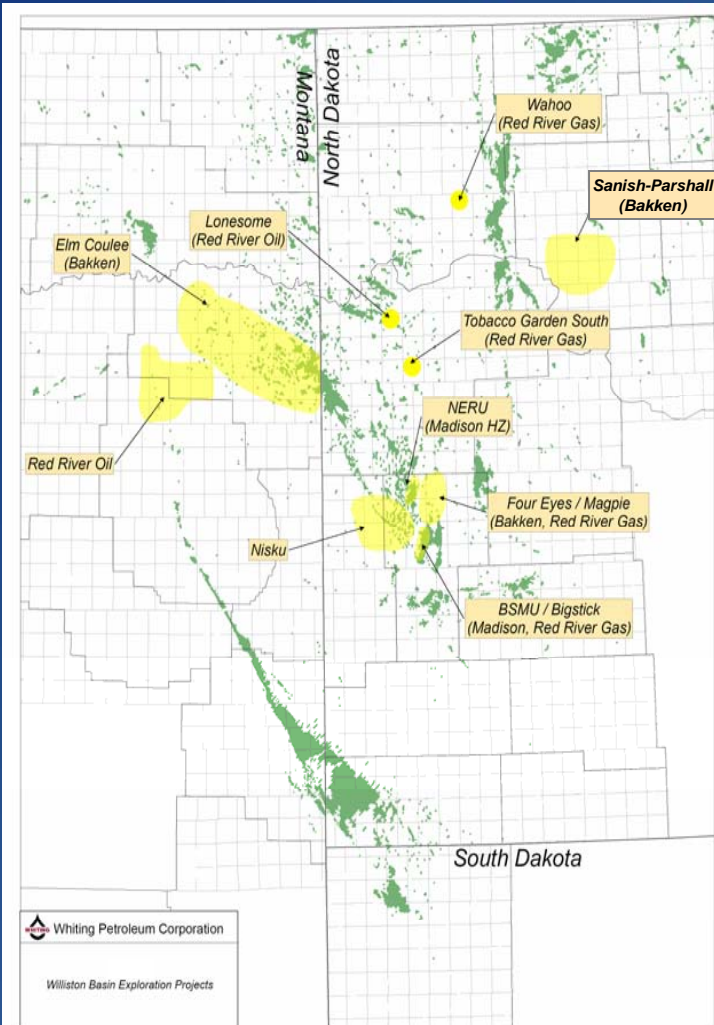


(1) Includes hedging adjustments.

Whiting Developed & Undeveloped Acreage By Core Area



Whiting Williston Basin Activity



323,295 Net Acres

◆ WILLISTON BASIN

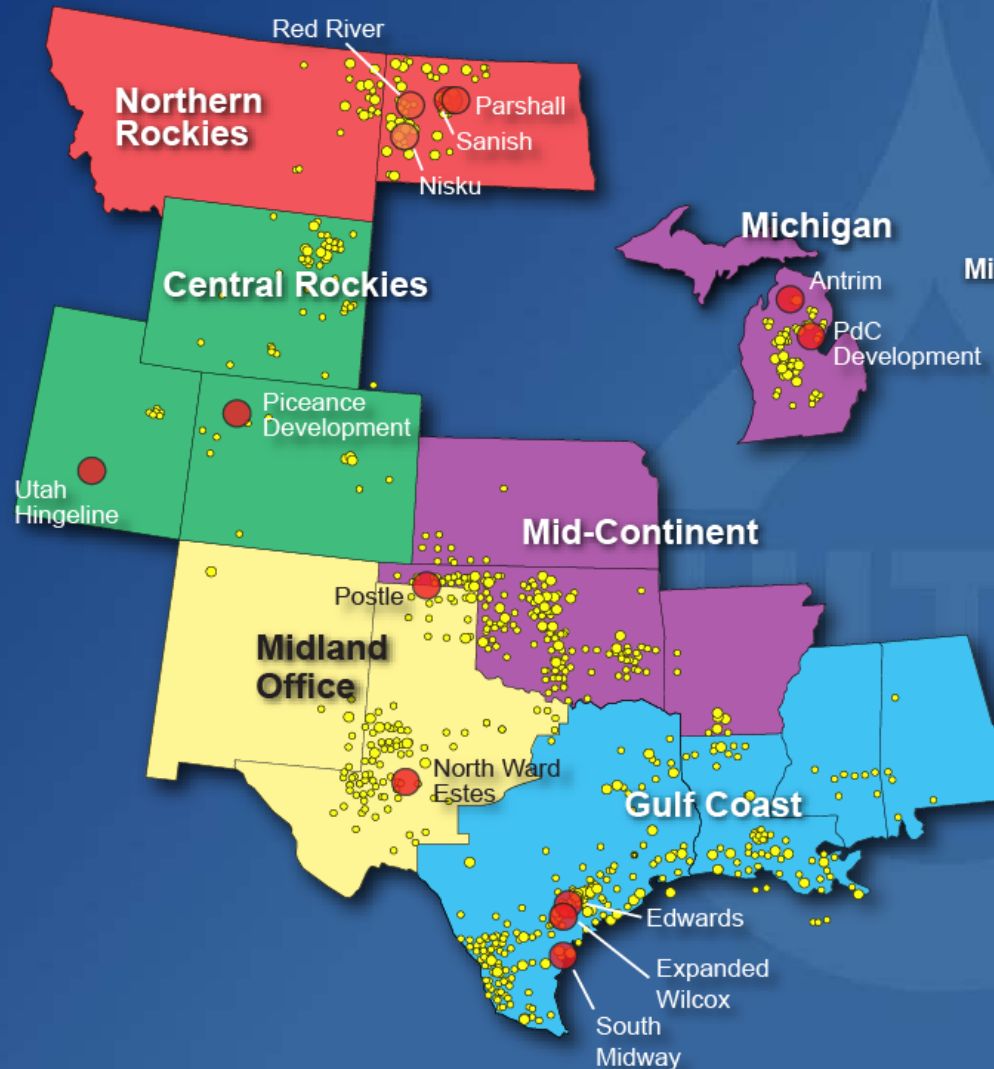
◆ BAKKEN EXPLORATION AREAS

- ◆ Basin-wide stratigraphic trap in dolomitic siltstone
- ◆ 185,305 gross; 96,503 net acres in Sanish field and Parshall field
- ◆ Avg. est. EUR 400 – 900 MBOE/well, avg. CWC \$5.5 MM to \$6.0 MM
- ◆ 33 wells drilled in 2007, approx. 36 operated wells and 20 non-operated wells planned for Sanish in 2008
- ◆ Approx. 50 to 60 non-operated wells planned for Parshall field in 2008

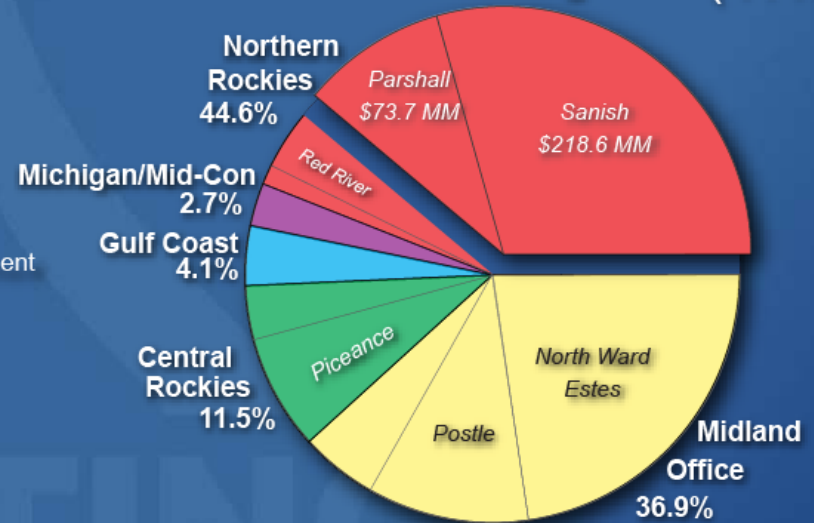
◆ RED RIVER EXPLORATION

- ◆ Nine 3-D seismic surveys acquired in 2005 to 2007 to identify structures. One 3-D planned for 2008
- ◆ 24 drilling prospects identified, 6 wells drilled in 2007, 7 wells planned for 2008
- ◆ Avg: EUR 450 Mboe; CWC \$2.5 MM - \$3.7 MM
- ◆ 9 of 11 successful wells (2005 – 2007) drilled using 3-D seismic to identify structures
- ◆ 7 wells and 1 new 3-D seismic program planned for 2008

WHITING OIL AND GAS CORPORATION 2008 BAKKEN CAPEX



Bakken Drilling = \$302 MM (41%)



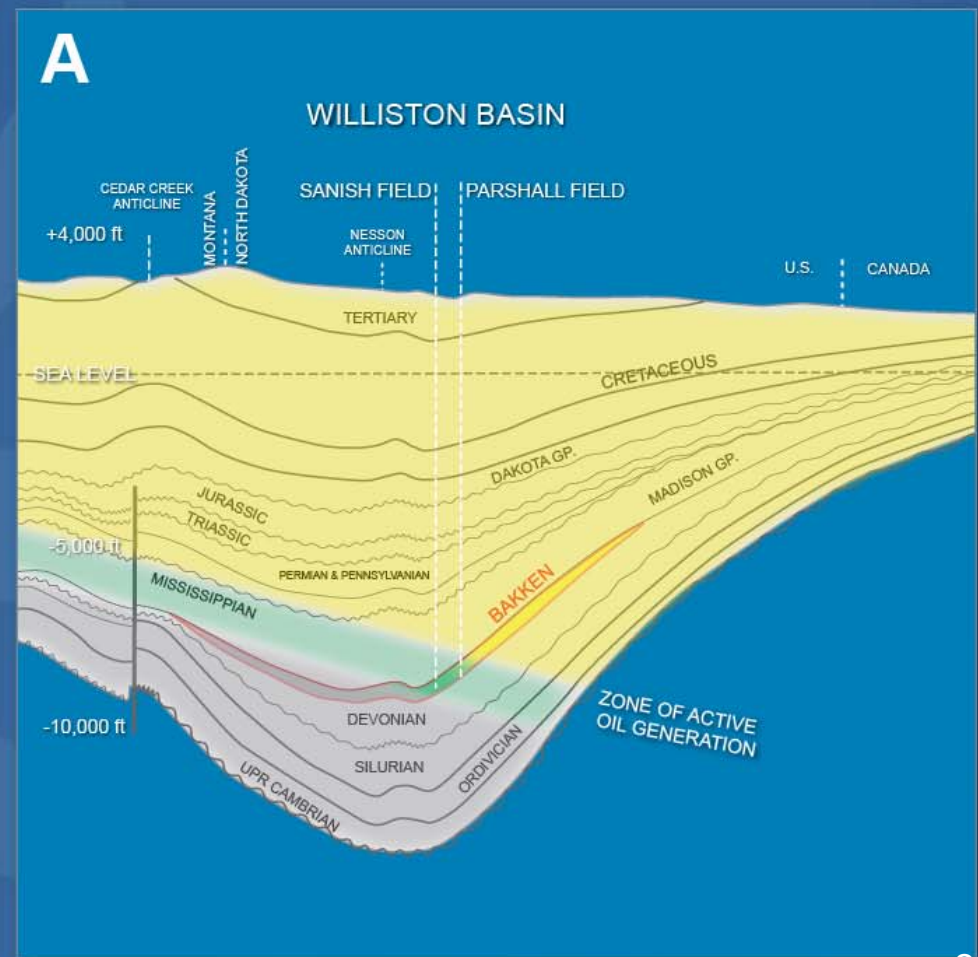
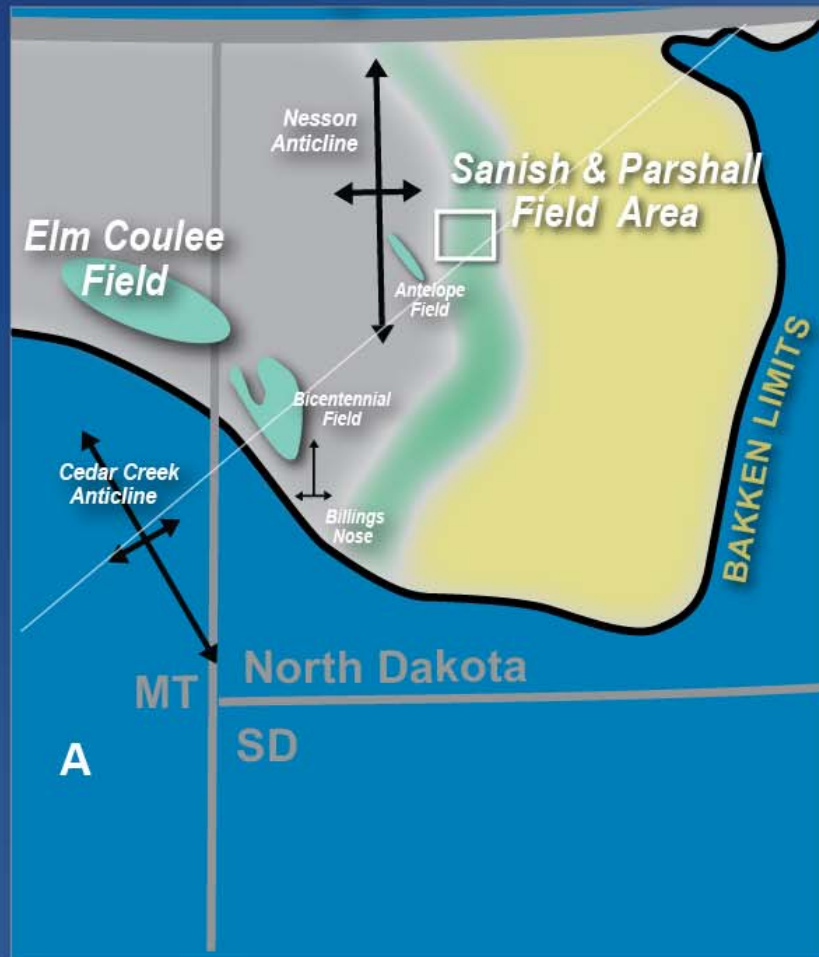
2008 Budget = \$740 MM

Williston Basin

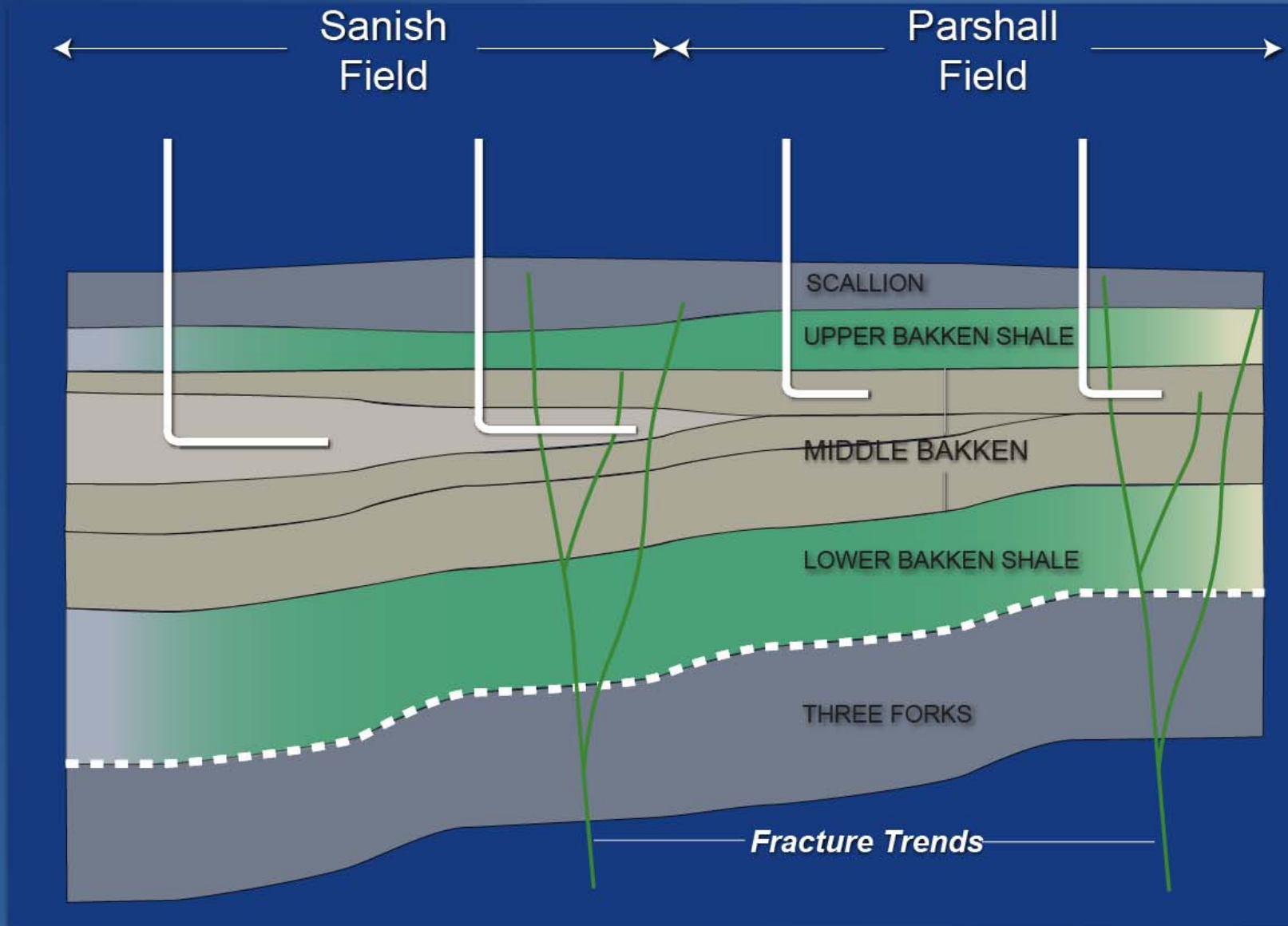
Sanish Field (*Robinson Lake Prospect*)
& Parshall Field



BAKKEN OIL GENERATION



BAKKEN CROSS-SECTION

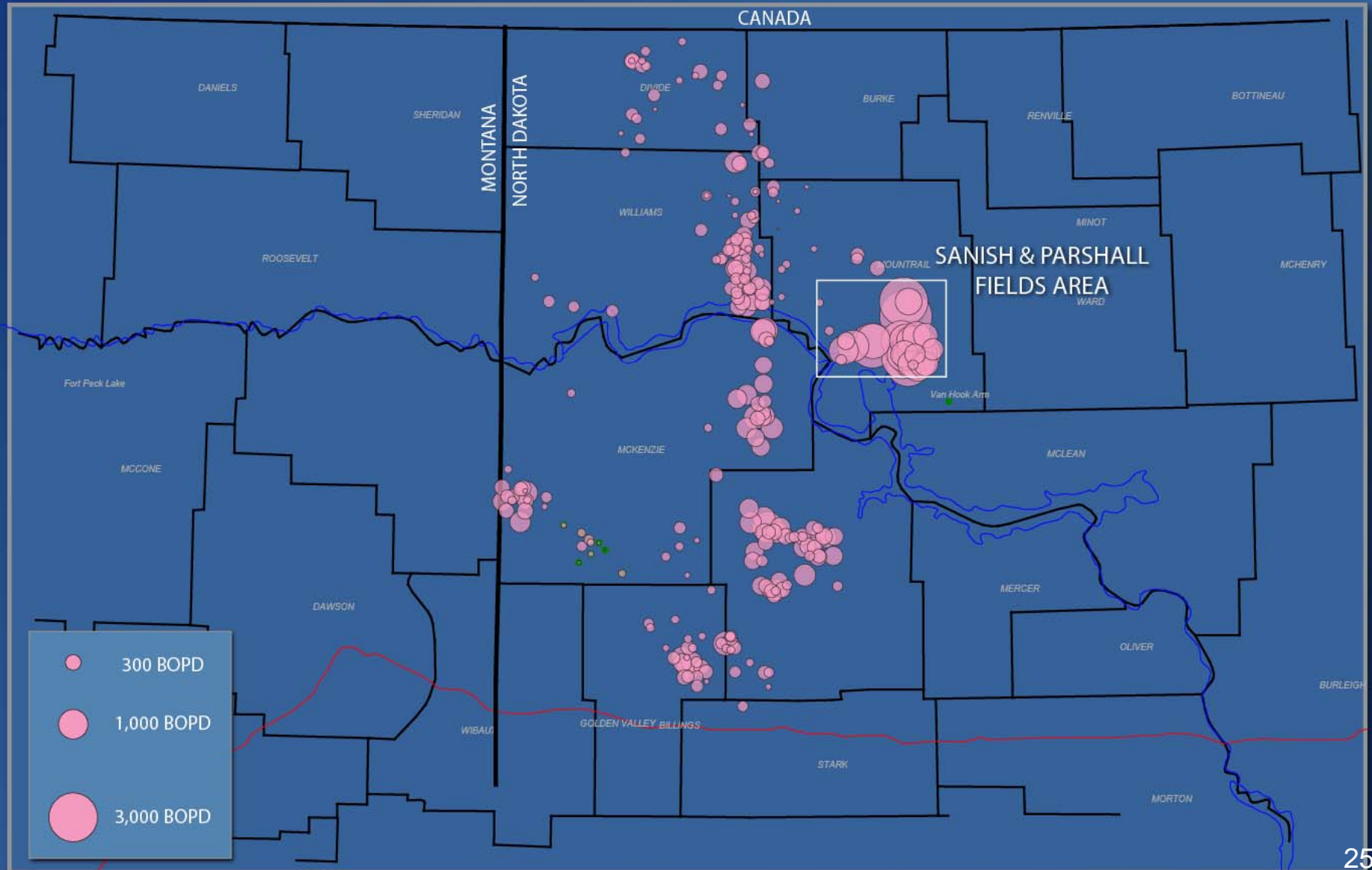


Reported Initial Oil Rate Bubbles

North Dakota Middle Bakken Horizontal Wells since 2000

North Dakota Industrial Commission

April, 2008

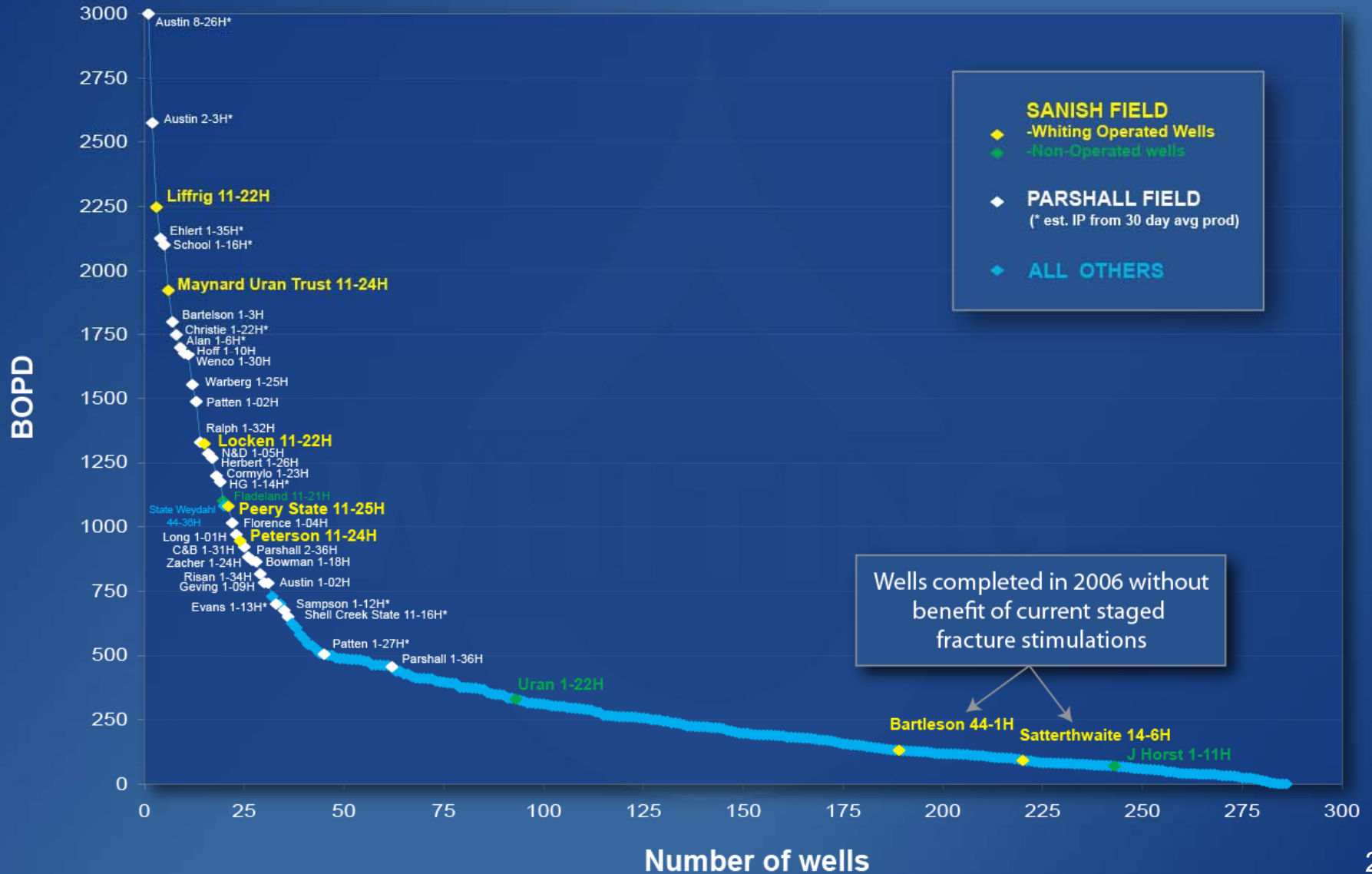


Reported Initial Oil Rate

North Dakota Middle Bakken Horizontal Wells since 2000

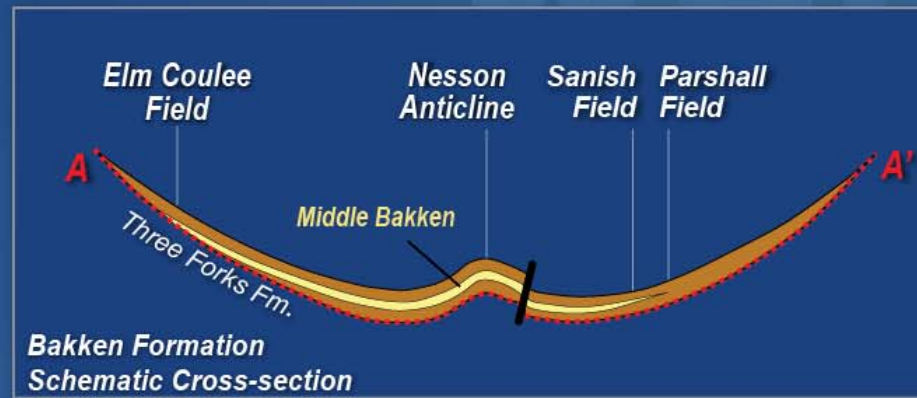
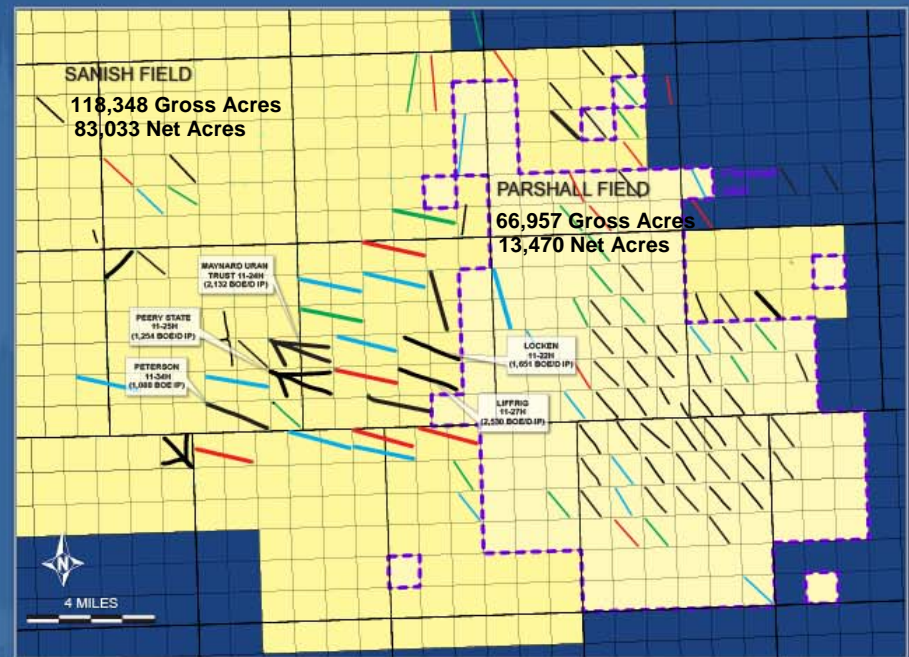
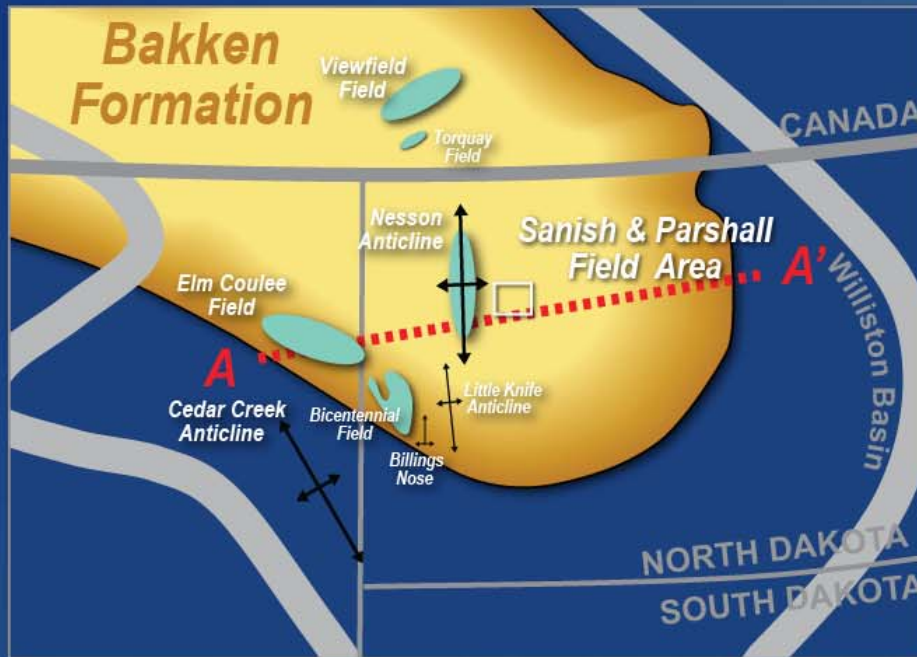
North Dakota Industrial Commission

April, 2008



Williston Basin

Sanish Field (Robinson Lake Prospect) & Parshall Field



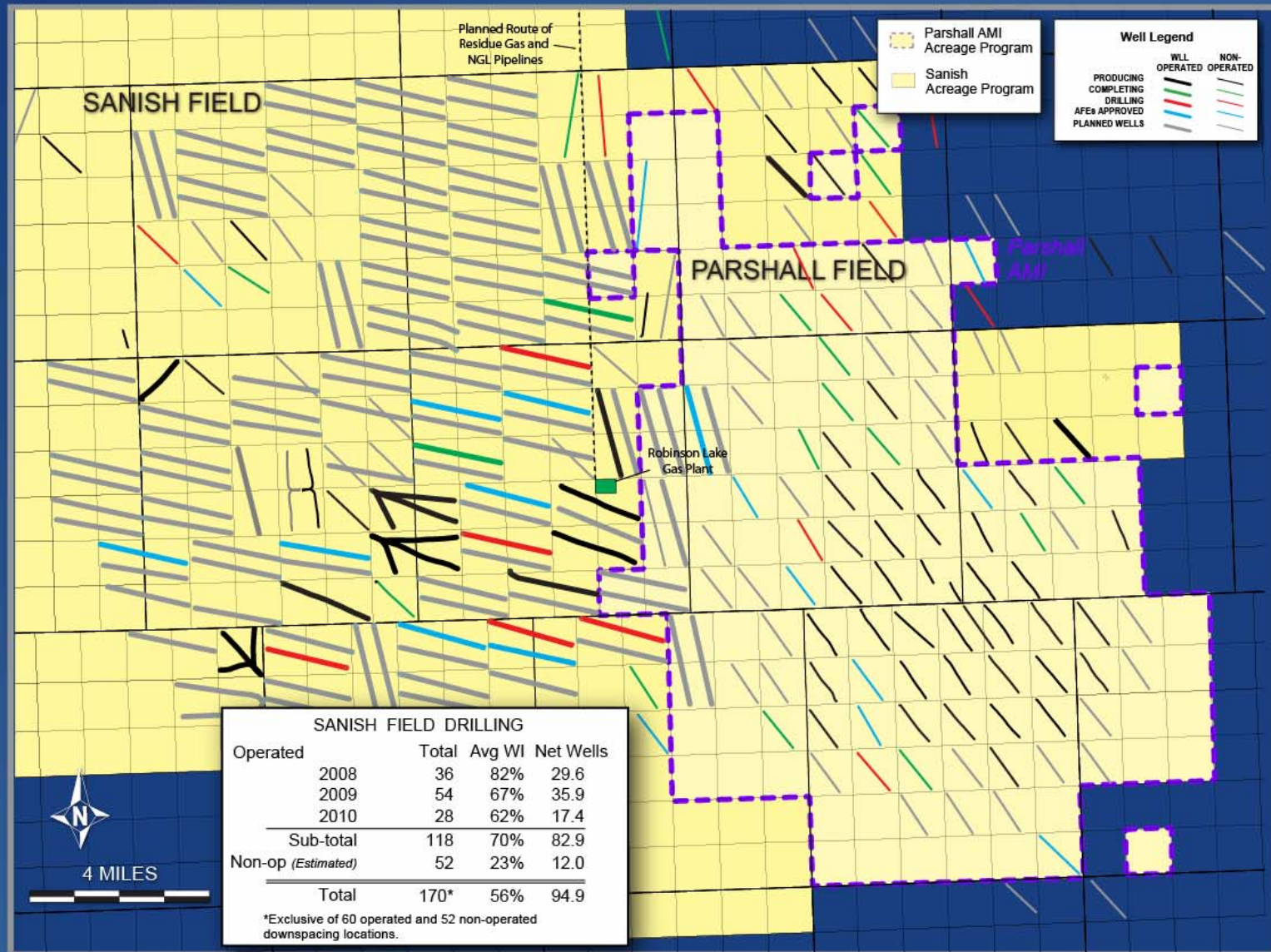
INITIAL RATES

Sanish Field					Parshall Field			
	Bopd	Mcfpd*	Boepd	Date		Bopd	Mcfpd*	Boepd
Peery State 11-25H	1,081	1,037	1,254	05/13/07	Avg of 1st 120 days prod (20 wells)	581	221	618
Locken 11-22H	1,323	1,968	1,651	12/16/07				
Liffing 11-27H	2,247	1,700	2,530	01/24/08				
Peterson 11-34H	945	858	1,088	03/20/08				
Maynard Uran 11-24H	1,923	1,251	2,132	04/23/08				
Avg 1st 30 days prod (WOGC operated wells completed since 6/07)	767	534	856					

Well Count (Whiting Interest Wells Only)			
		WELL	
		OPERATED	NON-OPERATED
PRODUCING	9	36	
COMPLETING	5	9	
DRILLING	7	7	
AFEs APPROVED	10	5	
2008 PLANNED WELLS (includes 20 Sanish non-operated wells)	50 to 60	50 to 60	

*Note: Gas sales are not expected before May, 2008

BAKKEN DRILLING PROGRAM

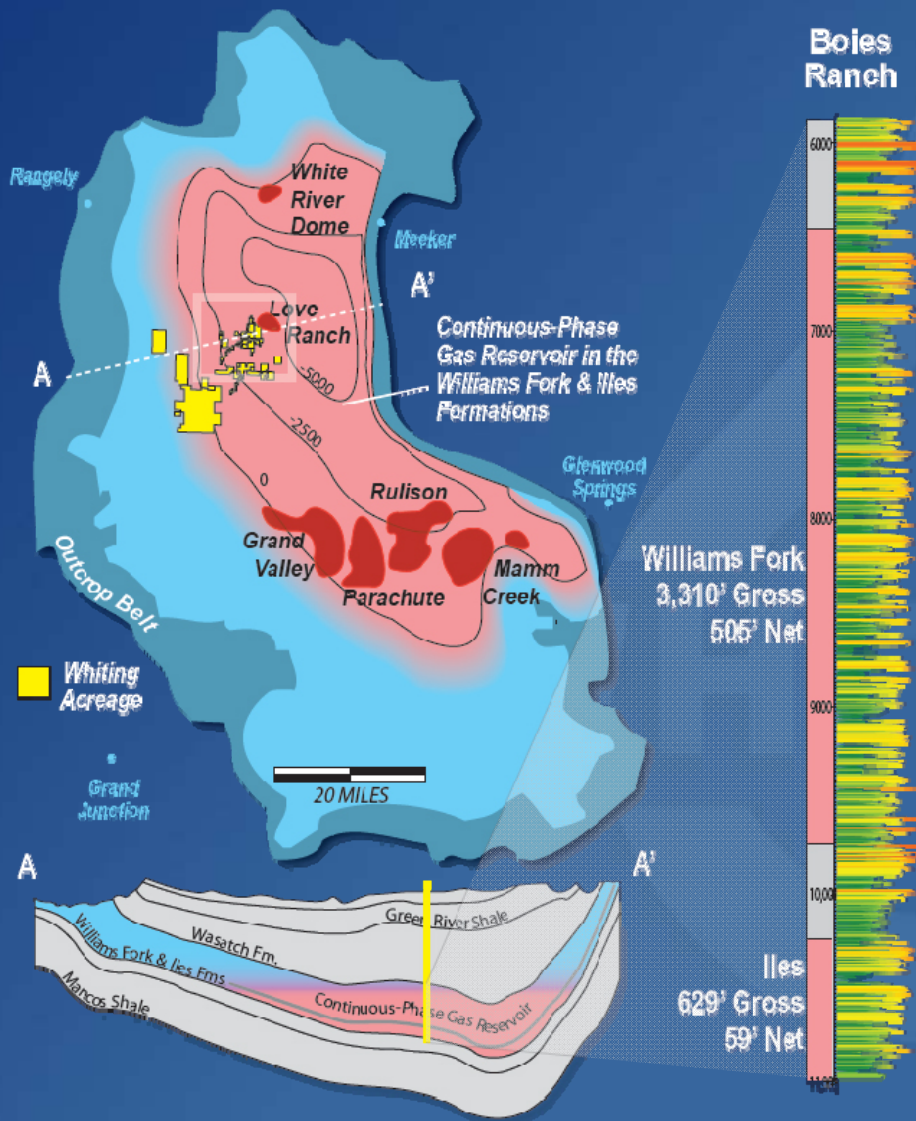


Sanish Field Bakken Completions



<u>Well Name</u>	<u>WI</u>	<u>NRI</u>	<u>Comp. Date</u>	<u>IP (BOE/D) 24-hr. Test</u>	<u>1st 30 Days (BOE/D)</u>	<u>Comment</u>
Maynard Uran Trust 11-24H	84%	68%	04/23/08	2,132	--	Triple Lateral
Peterson 11-34H	91%	75%	03/19/08	1,088	541	Single Lateral
Liffrig 11-27H	81%	67%	01/24/08	2,530	1,114	Single Lateral
Locken 11-22H	99%	82%	12/16/07	1,651	946	Single Lateral
Peery State 11-25H	99%	80%	05/13/07	1,254	825	Triple Lateral

Rockies Exploration – Piceance Basin

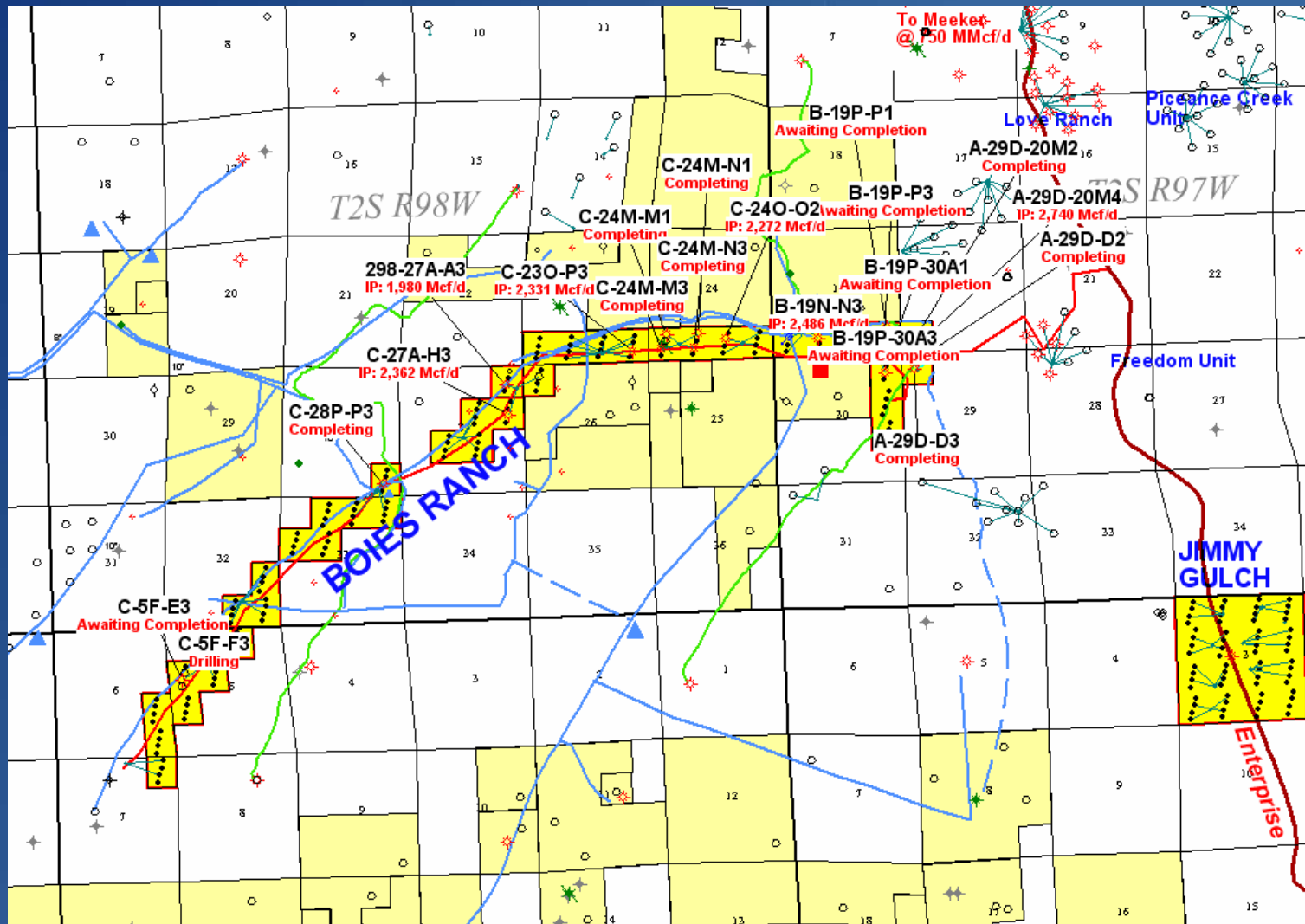


◆ Boies Ranch and Jimmy Gulch Prospects

- ◆ Operated: WI between 50% and 100%
- ◆ Continuous-phase gas in Williams Fork and Iles formations
- ◆ 110 wells planned (one per 20-acre unit)
- ◆ \$207 million remaining budget, including processing, at Dec. 31, 2007
- ◆ Cost per well: \$2.8 million per well (with stimulation)

Boies Ranch & Jimmy Gulch Prospects

Rio Blanco County, Colorado



Existing Wells used in Boies Ranch and Love Ranch Tables	•
Proposed Locations	• WLL - 110 Locations A-I WLL - Drilling areas
Working Interest	<div style="display: flex; align-items: center;"> <div style="width: 15px; height: 15px; background-color: #ffff00; border: 1px solid black; margin-right: 5px;"></div> WLL - 50% - 100% WI </div> <div style="display: flex; align-items: center; margin-top: 5px;"> <div style="width: 15px; height: 15px; background-color: #ffffcc; border: 1px solid black; margin-right: 5px;"></div> WLL - 4% - 50% WI </div>
Gathering System	<div style="display: flex; align-items: center; margin-bottom: 5px;"> <div style="width: 20px; height: 2px; background-color: red; margin-right: 5px;"></div> WLL - Gathering </div> <div style="display: flex; align-items: center; margin-bottom: 5px;"> <div style="width: 20px; height: 2px; background-color: orange; margin-right: 5px;"></div> WLL - On Sale </div> <div style="display: flex; align-items: center; margin-bottom: 5px;"> <div style="width: 20px; height: 2px; background-color: green; margin-right: 5px;"></div> Williams - Gathering </div> <div style="display: flex; align-items: center; margin-bottom: 5px;"> <div style="width: 20px; height: 2px; background-color: blue; margin-right: 5px;"></div> 3rd Party - Gathering </div> <div style="display: flex; align-items: center; margin-bottom: 5px;"> <div style="width: 20px; height: 2px; background-color: lightblue; margin-right: 5px;"></div> 3rd Party - Future Gathering </div> <div style="display: flex; align-items: center;"> <div style="width: 10px; height: 10px; background-color: lightblue; border: 1px solid black; margin-right: 5px;"></div> 3rd Party - Future Compressors </div>

Average Initial Rate
2,362 Mcf/d

Current Status

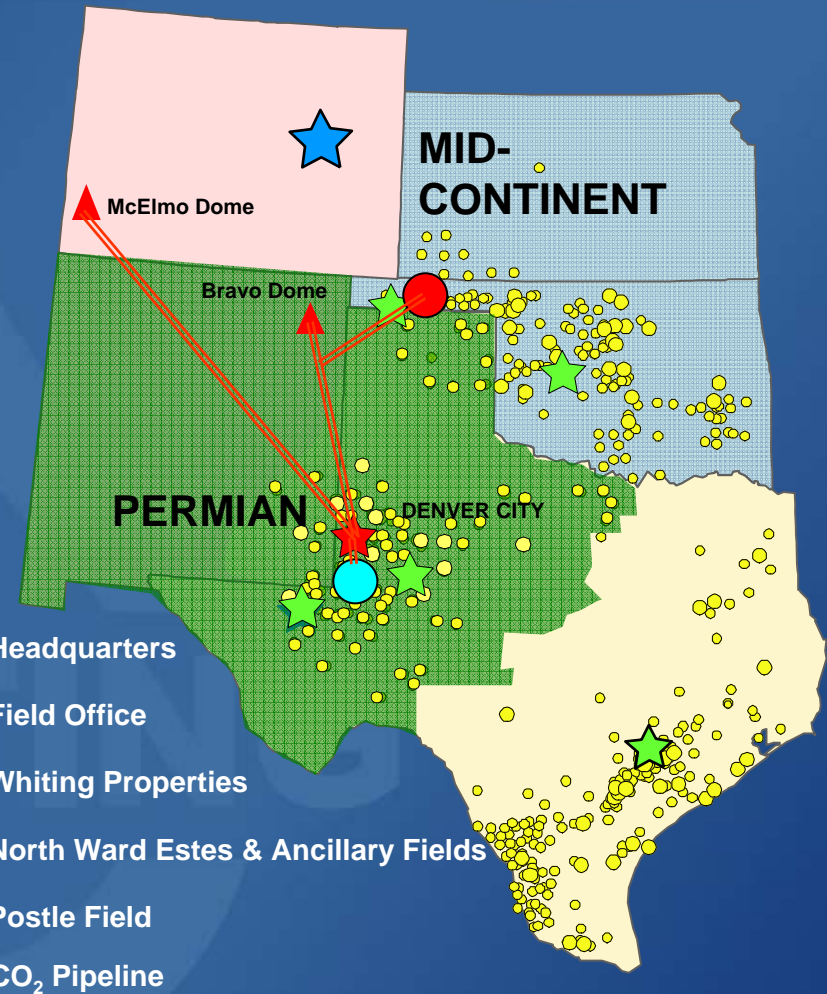
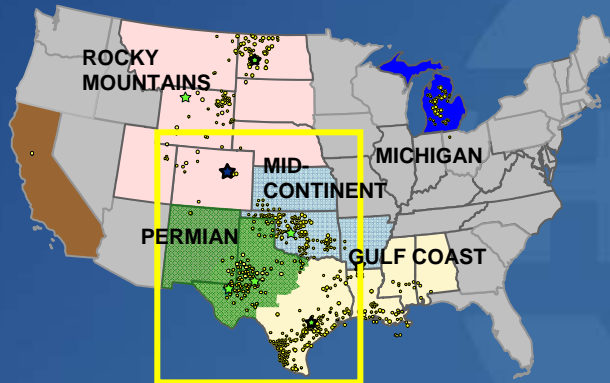
Drilling:	2
Completing:	6
WOC:	4
Producing:	6
Total:	16

Postle and North Ward Estes Fields Build in Core Areas



	Whiting	Postle N. Ward Estes	Total Whiting	% Postle/NWE
12/31/07 Proved Reserves⁽¹⁾				
Oil - MMBbl	80.5	115.8	196.3	59%
Gas - Bcf	278.0	48.7	326.7	15%
Total - MMBOE	126.9	123.9	250.8	49%
% Crude Oil	65%	92%	78%	
March 2008 Production				
Total - MBOE/d	29.6	12.2	41.8	29%

Whiting Properties



- Headquarters
- Field Office
- Whiting Properties
- North Ward Estes & Ancillary Fields
- Postle Field
- CO₂ Pipeline

Postle and North Ward Estes Fields Complement Whiting's Core Areas

(1) Based on independent engineering by Cawley Gillespie & Associates, Inc. at December 31, 2007.

Total Postle, N. Ward Estes and Ancillary Properties



Fully Developed Costs Per BOE

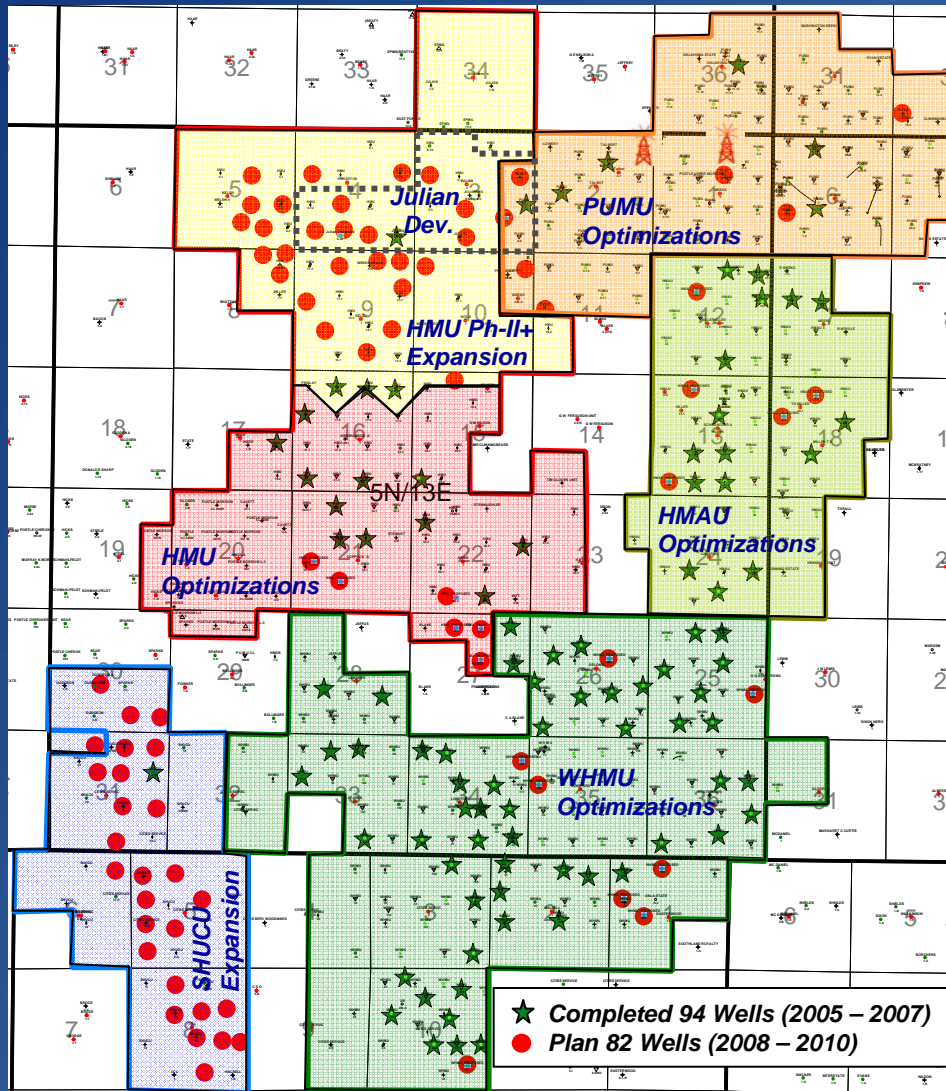
	Net (MM\$)	Reserves or Production (Net MMBOE)	Acq. and Dev. Cost (\$/BOE)
Acquisition Purchase Price (effective 7/1/05)	\$ 802		
Remaining Proved at 12/31/07 – Capex / Reserves	902 ⁽¹⁾	123.9	
Six Months 2005 – Capex / Production	75	1.9	
2006 – Capex / Production	221	4.3	
2007 – Capex / Production	285	4.4	
2006 & 2007 Divestments – Sales Price	(8)	-	
Total Actual Plus Proved at 12/31/07 – Capex / Reserves	2,277 ⁽¹⁾	134.5	\$16.93 ⁽²⁾
Probable and Possible at 12/31/07 – Capex / Reserves	154	94.4	
Total Actual Plus All Reserve Cats. – Capex / Reserves	\$2,431	228.9	\$10.62 ⁽²⁾

(1) More than half of the \$225 MM (11%) increase in the all-in proved cost estimate, from \$2,052 MM at year-end 2006 to \$2,277 MM at year-end 2007, is attributable to the NYMEX indexed CO₂ price at North Ward Estes.

(2) Estimated capital expenditures reflect an expanded scope in planned projects as well as the increasing cost of industry equipment and services and CO₂. Although total acquisition and development costs increased 11%, the pre-tax PV10 value of these fields increased from \$1,417 MM at year-end 2006 to \$2,924 MM at year-end 2007, a 106% increase.

Development Plans – Postle Field

(\$ in millions)



24,223 Net Acres

2008 – 2010 Drilling Inventory

	Number of Wells
PUMU Optimizations	7
HMAU Optimizations	5
WHMU Optimizations	8
HMU Optimizations	6
HMU Ph-II+ Expansions	27
SHUCU Expansion	27
Julian Development	2
Total:	82

Total Remaining Capital Expenditures (1)

	Amount
Drilling, Completion & Dry Trail Gas Plant Cost	\$107
CO ₂ Purchases	152
Total	\$259

(1) Based on independent engineering at Dec. 31, 2007.

Dry Trail Gas Plant



Train I

- ◆ Capacity: 43 MMcfpd
- ◆ Type: Ryan – Holmes
- ◆ Compression: Gas



Train II

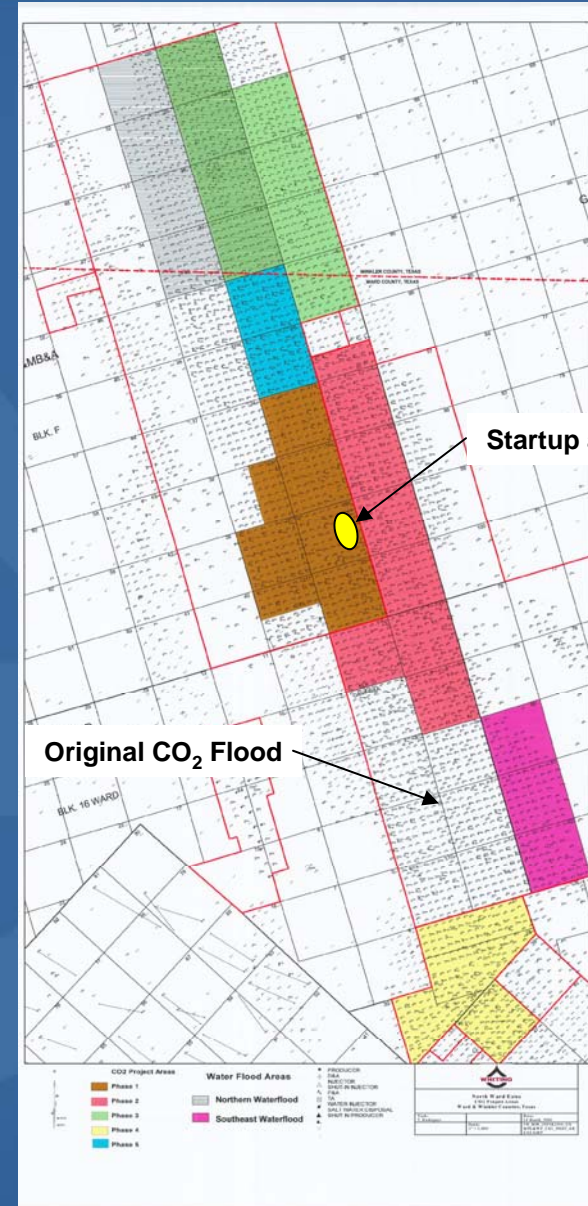
- ◆ Capacity: 50 MMcfpd
- ◆ Type: Membranes
- ◆ Compression: Electric
- ◆ Advantages
 - ◆ Modular
 - ◆ Energy efficient



CO₂ Flood – North Ward Estes



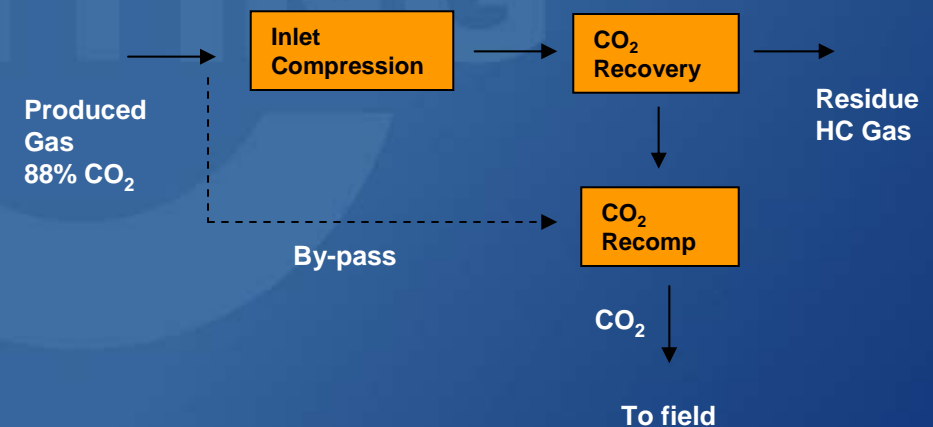
- ◆ 28 sections planned
- ◆ ~700 MMBO OOIP in flood area
- ◆ Proved recovery target – 5% based on original flood
- ◆ CO₂ supply agreement in place
 - ◆ Contract quantity: 269 BCF
 - ◆ Deliveries:
 - ◆ 2007 – 10 MMcfpd
 - ◆ 2008 – 100+ MMcfpd
- ◆ Start-up – 05/07
- ◆ Current Status
 - ◆ 91 injectors
 - ◆ 120+ MMcfpd CO₂ injection



CO₂ Recovery Plant – North Ward Estes

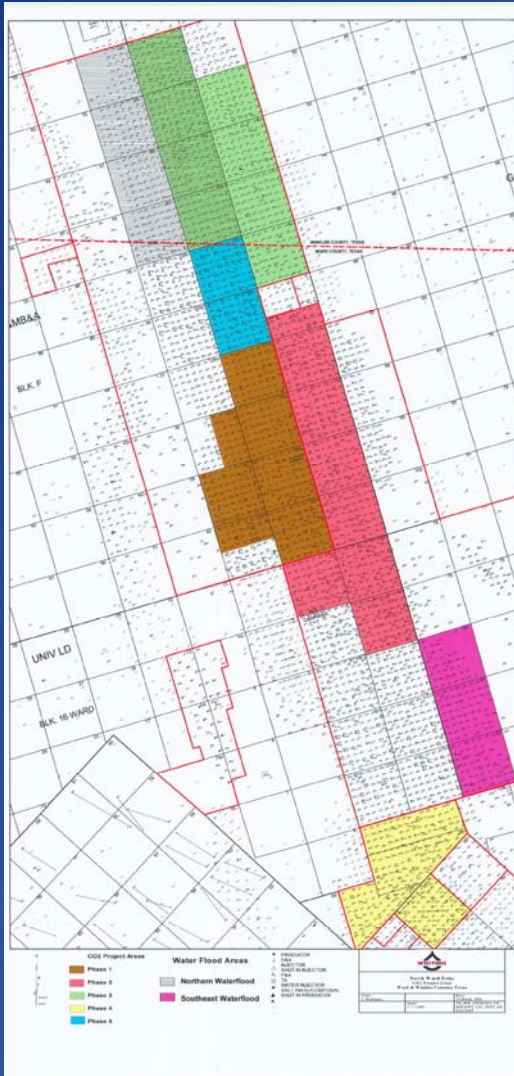


- ◆ Type: Membrane Plant
- ◆ Total Capacity: 120 MMcfpd
- ◆ Three Trains
- ◆ Three Components
 - ◆ Inlet Compression
 - ◆ Membranes
 - ◆ CO₂ Recompression
- ◆ Standard Design
- ◆ Advantages
 - ◆ Modular
 - ◆ Energy Efficient



Development Plans – North Ward Estes Field

(\$ in millions)



58,000 Net Acres

Project Timing

Project	Injection Start
Phase 1 CO ₂ Area	2007 & 2008
Phase 2 CO ₂ Area	2009
Phase 3 CO ₂ Area	2011
Phase 4 CO ₂ Area	2013
Phase 5 CO ₂ Area	2015

Total Remaining Capital Expenditures⁽¹⁾

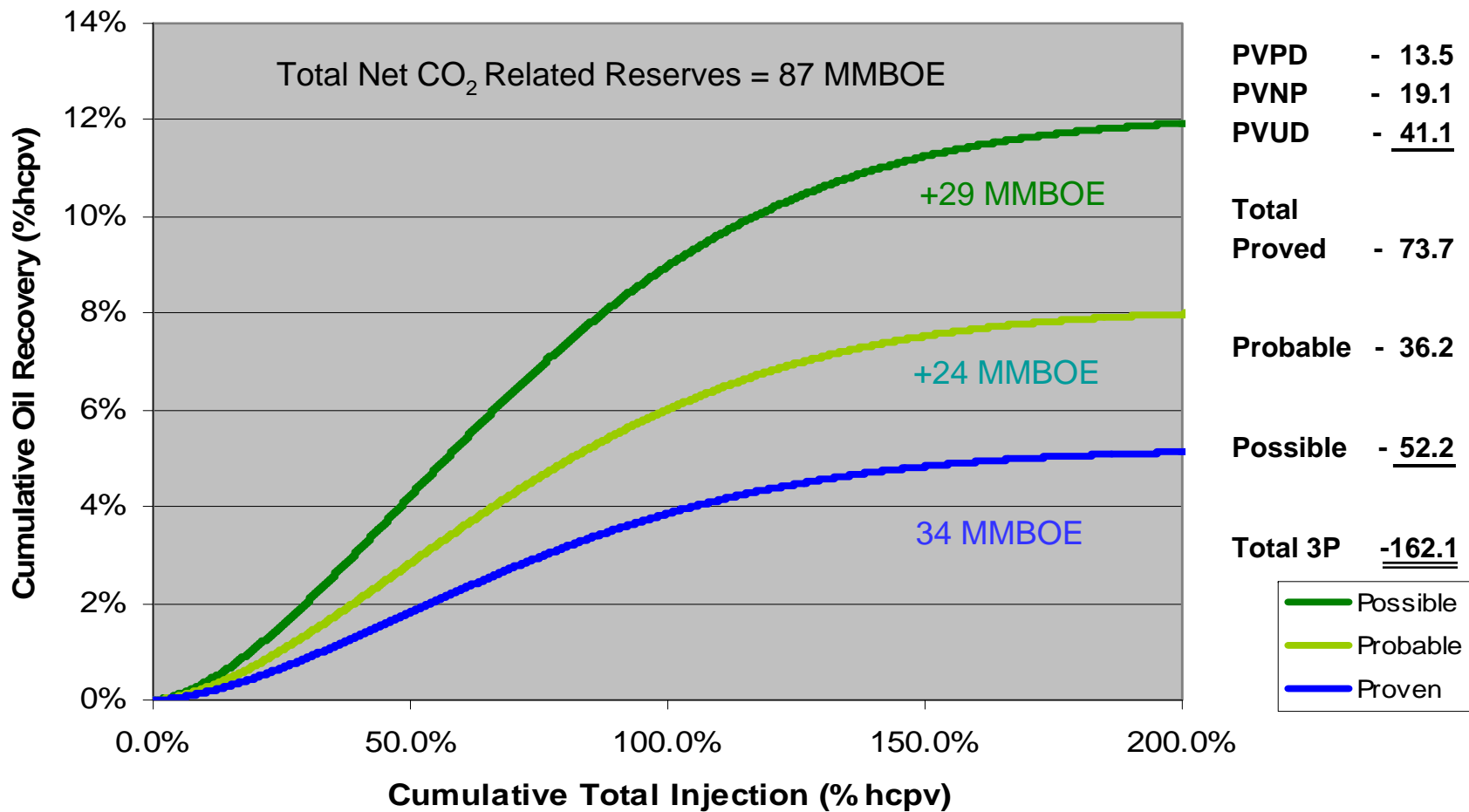
	Amount
Drilling, Completion, Waterflood Restoration (Non-CO ₂) & Gas Plant Costs	\$253
CO ₂ Purchases	372
Total	\$625

(1) Based on independent engineering at Dec. 31, 2007.

Estimated Net Reserves from CO₂ Flood – North Ward Estes



Total Net Proved, Probable & Possible CO₂ Reserves at 12/31/07 = 87 MMBOE
 Total Net Proved, Probable & Possible Reserves from All Sources at 12/31/07 = 162 MMBOE



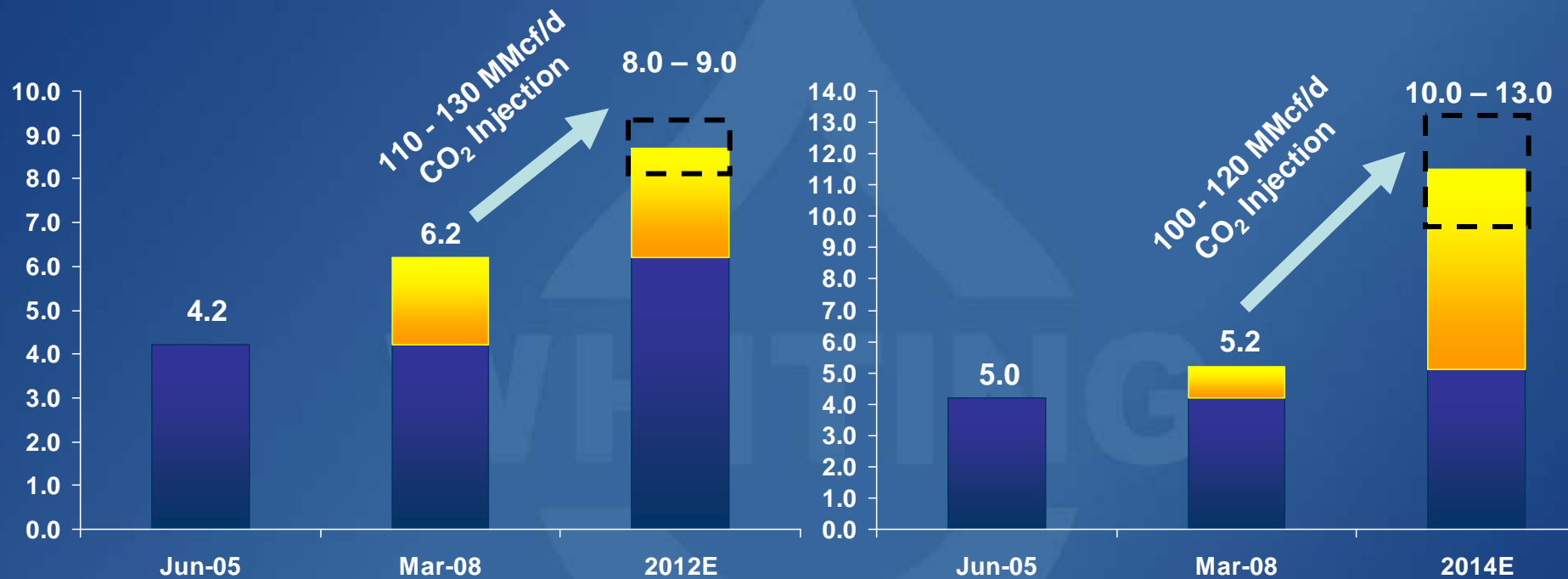
hcpv = hydrocarbon pore volume

Net Production Growth From CO₂ Projects⁽¹⁾



Postle Field

North Ward Estes Field



(1) Net production numbers are in thousands of barrels of oil equivalent per day. The estimated ranges of production are based on 90% to 100% of independent engineering at Postle and 80% to 100% of independent engineering at North Ward Estes. Actual results may vary.

Hedging Strategy



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

Existing Oil Hedge Positions⁽¹⁾

<u>Period</u>	<u>Hedged Volumes (Bbls per Month)</u>	<u>% of Oil Volume During March 2008</u>	<u>Weighted Average Hedge Price Range (\$/Bbl)</u>
Q2 2008	330,000	36%	57.52 – 75.41
Q3 2008	330,000	36%	57.52 – 75.65
Q4 2008	330,000	36%	57.52 – 75.59

(1) As of April 15, 2008.

Note: Table does not include two fixed price contracts:
26,000 MMBtu per month through 05/2011 at \$4.94 per MMBtu with 4% annual escalator.
67,000 MMBtu per month through 09/2012 at \$4.38 per MMBtu with 4% annual escalator.

Trust Hedges – 24.2% Whiting



In conjunction with the Whiting USA Trust I, we entered into certain oil and natural gas hedges. No additional hedges are allowed to be placed on trust assets. All future economic benefits or detriments of the hedge contracts listed below have been transferred to the trust and included in the calculation of net proceeds under the trust. Under the trust, Whiting retains 10% of the net proceeds from the underlying properties. Whiting's 10% of these net proceeds combined with its ownership of 2,186,389 trust units results in third-party public holders of trust units receiving 75.8%, and Whiting retaining 24.2%, of the future economic results of such hedge contracts.

Period	Contracted Volumes		NYMEX Price Collar Range	
	Natural Gas (Mcf per Month)	Oil (Bbls per Month)	Gas (per MMBtu)	Oil (per Bbl)
2008	241,073	52,920	\$7.00 – \$16.06	\$82.00 - \$133.20
2009	198,974	48,166	\$6.50 – \$17.11	\$76.00 - \$137.43
2010	170,589	43,488	\$6.50 – \$15.06	\$76.00 - \$134.98
2011	150,313	39,614	\$6.50 – \$14.62	\$74.00 - \$140.15
2012	132,232	36,189	\$6,50 – \$14.27	\$74.00 - \$141.72

Chicago Energy Acquisition – Key Points



- ◆ **Acquired Interests in the Flat Rock Natural Gas Field in Uintah County, Utah (Uinta Basin) for \$365 Million (\$2.86 per Mcfe)**
 - ◆ 115.2 Bcfe of proved reserves
 - ◆ Includes 7 wells that produce from the Entrada sandstone formation and 24 wells that produce from the Wasatch and Dakota formations
 - ◆ Includes gas gathering and processing facilities
 - ◆ Includes interests in 22,029 gross acres (11,534 net acres)
- ◆ **Net production of 19 MMcfe per day in March 2008 (83% operated by Whiting)**
 - ◆ 97% of current production is from the Entrada formation at 11,500'
 - ◆ 98% of reserves natural gas
 - ◆ 22% of reserves proved developed producing and 78% proved undeveloped
 - ◆ Additional 59 Entrada development wells planned

Chicago Energy Acquisition – Property Map

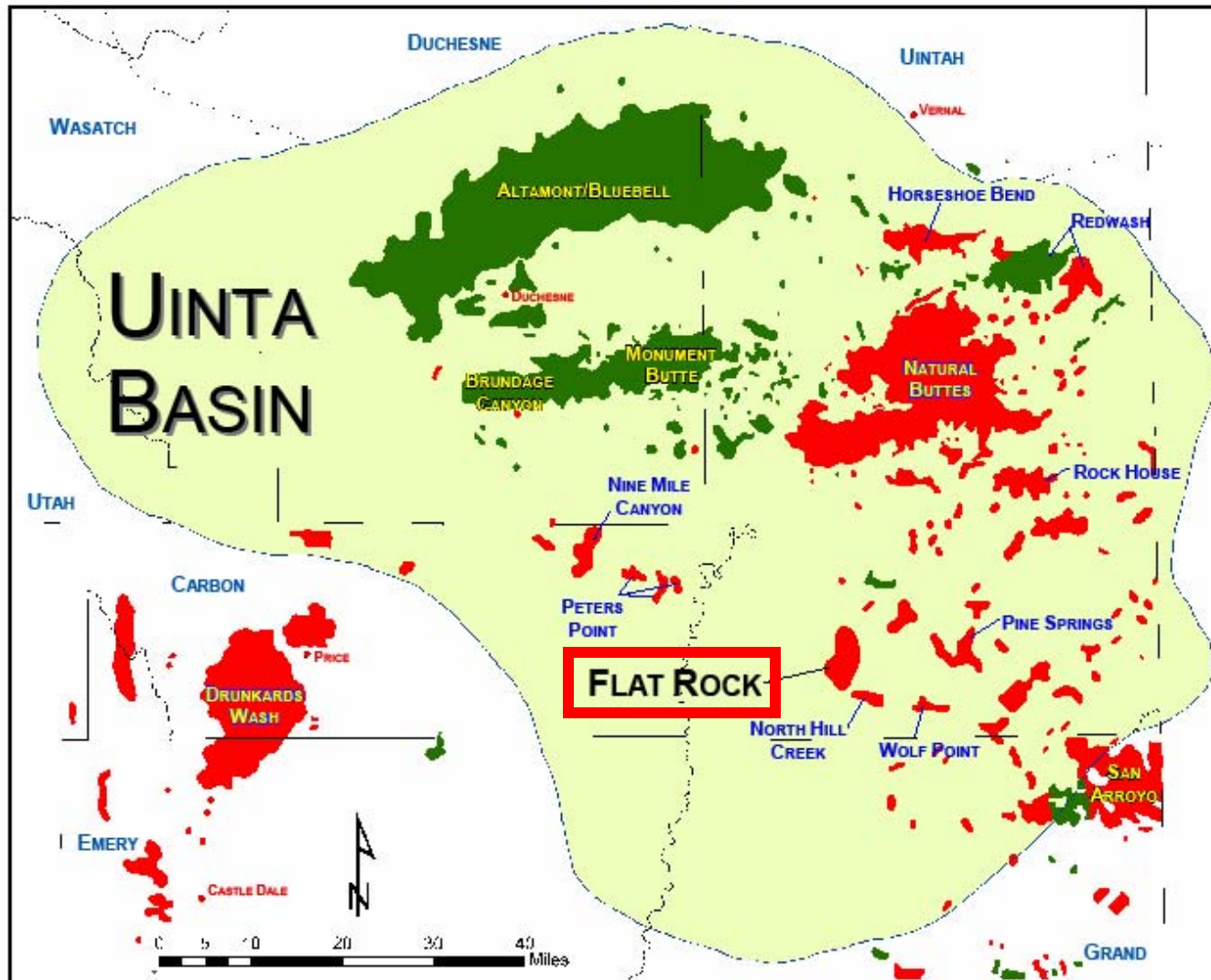


Figure 1. Modified from Utah Geological Survey Map 203DM 2004

In Summary



- ◆ Geographically diversified, long-lived reserve base → ◆ 5 Core Regions; 16.4 year R/P @ March '08
Grown from 71.7 MMBOE at IPO to 250.8 MMBOE
- ◆ Disciplined acquirer with strong record of accretive acquisitions → ◆ 13 acquisitions in 2004 – 2007; 208.4 MMBOE at \$7.08 per BOE average acquisition cost
- ◆ Multi-year inventory of development and exploitation projects to drive organic production → ◆ 5+ year drilling inventory
◆ Significant production growth potential from CO₂ recovery projects
- ◆ Exploration potential in the Rockies, Permian Basin and Gulf Coast → ◆ Williston: Sanish and Parshall fields
Piceance: Boies Ranch / Jimmy Gulch prospect areas
Uinta: Flat Rock field
Permian: Penn, Devonian and Montoya
Gulf Coast: Expanded Wilcox
- ◆ Commitment to financial strength → ◆ 31.0% total debt to total capitalization @ April 30, 2008, 41% @ May 30, 2008
- ◆ Proven management and technical team → ◆ Average 25+ years of experience

Discretionary Cash Flow ⁽¹⁾



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

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Net cash provided by operating activities.....	\$ 122,453	\$ 62,361
Exploration.....	8,412	6,860
Changes in working capital.....	<u>30,567</u>	<u>4,842</u>
Discretionary cash flow.....	<u>\$ 161,432</u>	<u>\$ 74,063</u>

(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, unrealized derivative gains/losses and other non-current items less the gain on sale of properties and marketable securities. 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.

Discretionary Cash Flow ⁽¹⁾

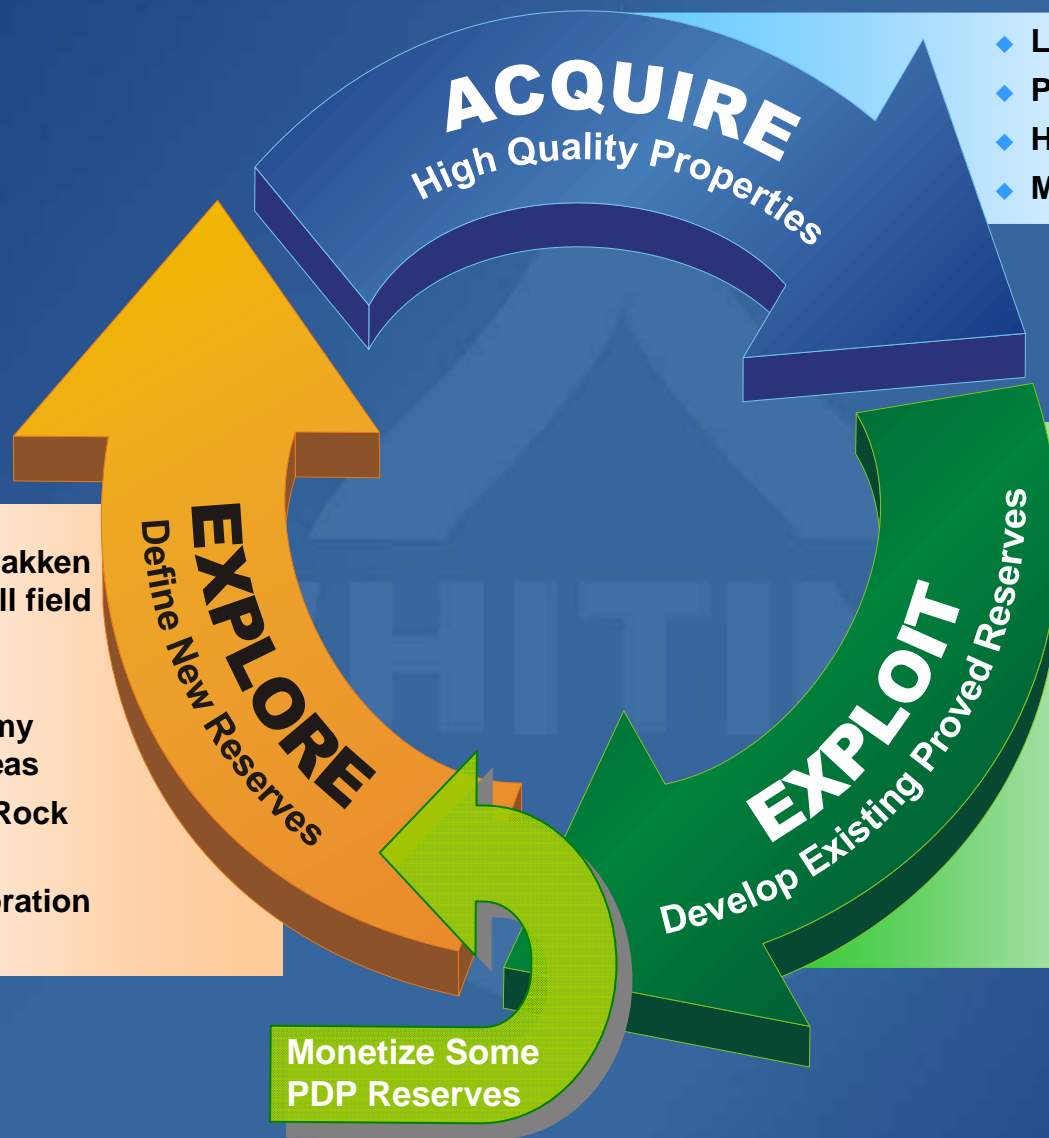


Reconciliation of Net Cash Provided by Operating Activities to Discretionary Cash Flow (In Thousands)

	Three Months Ended			
	3/31/07	6/30/07	9/30/07	12/31/07
Net cash provided by operating activities.....	\$ 62,361	\$ 87,592	\$ 122,656	\$ 121,423
Exploration.....	6,860	4,318	7,903	8,263
Changes in working capital.....	4,842	8,268	(22,533)	10,208
Discretionary cash flow.....	<u>\$ 74,063</u>	<u>\$ 100,178</u>	<u>\$ 108,026</u>	<u>\$ 139,894</u>

(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, unrealized derivative gains/losses and other non-current items less the gain on sale of properties and marketable securities. 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.

Our Formula for Success



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

- ◆ Williston Basin – Bakken Sanish and Parshall field areas
- ◆ Piceance Basin – Boies Ranch / Jimmy Gulch prospect areas
- ◆ Uinta Basin – Flat Rock field
- ◆ New Rockies exploration areas

- ◆ Permian Basin – North Ward Estes
- ◆ Williston Basin – North Elkhorn Ranch field
- ◆ Anadarko Basin – Postle field
- ◆ Green River Basin – Siberia Ridge field, Anderson Canyon field