

Beyond Primary and Secondary Recovery Business Case for Conventional EOR

Blaine Hawkins

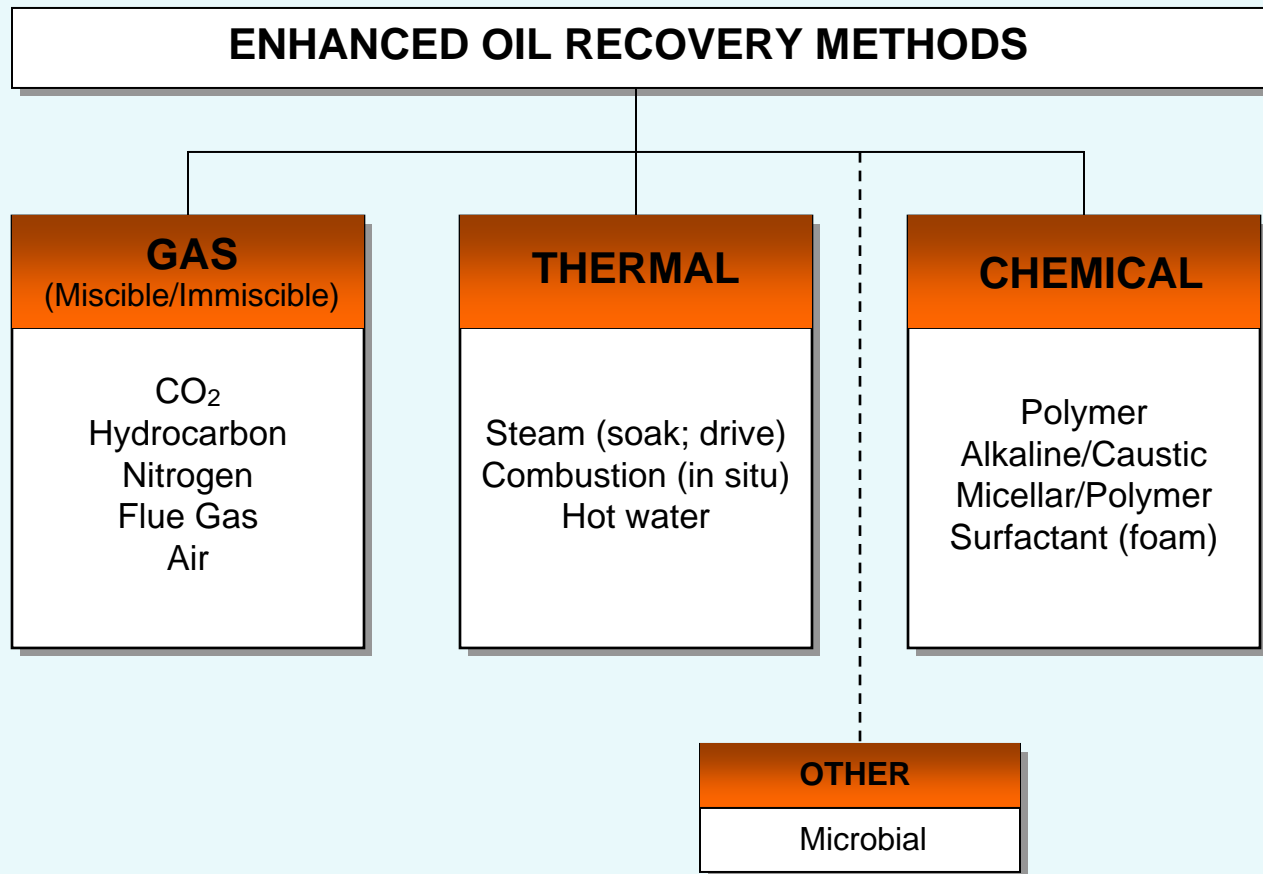
Manager, Conventional Oil & Natural Gas
Business Unit

Alberta Research Council

Outline

- Enhanced Oil Recovery - Current Status
- Alberta Reserves Picture and EOR Contribution
- Where to go from here?
 - IETP
 - Ongoing projects
- Opportunity Areas
 - Improved Water Flooding
 - CO₂ Miscible Flooding
- Example Economic Assessment
- Conclusions

Enhanced Oil Recovery



Worldwide EOR Production

- EOR Production is currently ~2.5 MM BOPD
- Represents 3.5% of the world's production
- Some projections reach 30 MM BOPD by year 2020

Oil Production (thousands of barrels/day)

	World	U.S.	Canada
Total Production	72,000	4,700	2,500
EOR Production (includes thermal)	2,500	649	325
Percent of Total Production	3.2	13.8	13.0

Sources: EOR data April, 2006, Oil & Gas Journal; Total production data, Dec, 2005, Oil & Gas Journal

EOR Oil Production (thousands of barrels/day) [2004 data]

	Number of Projects	U.S.	Canada
Thermal	55 [56] 15	302 [345]	292 [270]
Gas/Solvent	97 [83] 30 [32]	348 [318]	52 34 [42]
Chemical	0 [4] 0	0 [0.06]	0

Sources: April, 2006 data, Oil & Gas Journal; Canada Gas/Solvent; red includes recent production data from Weyburn

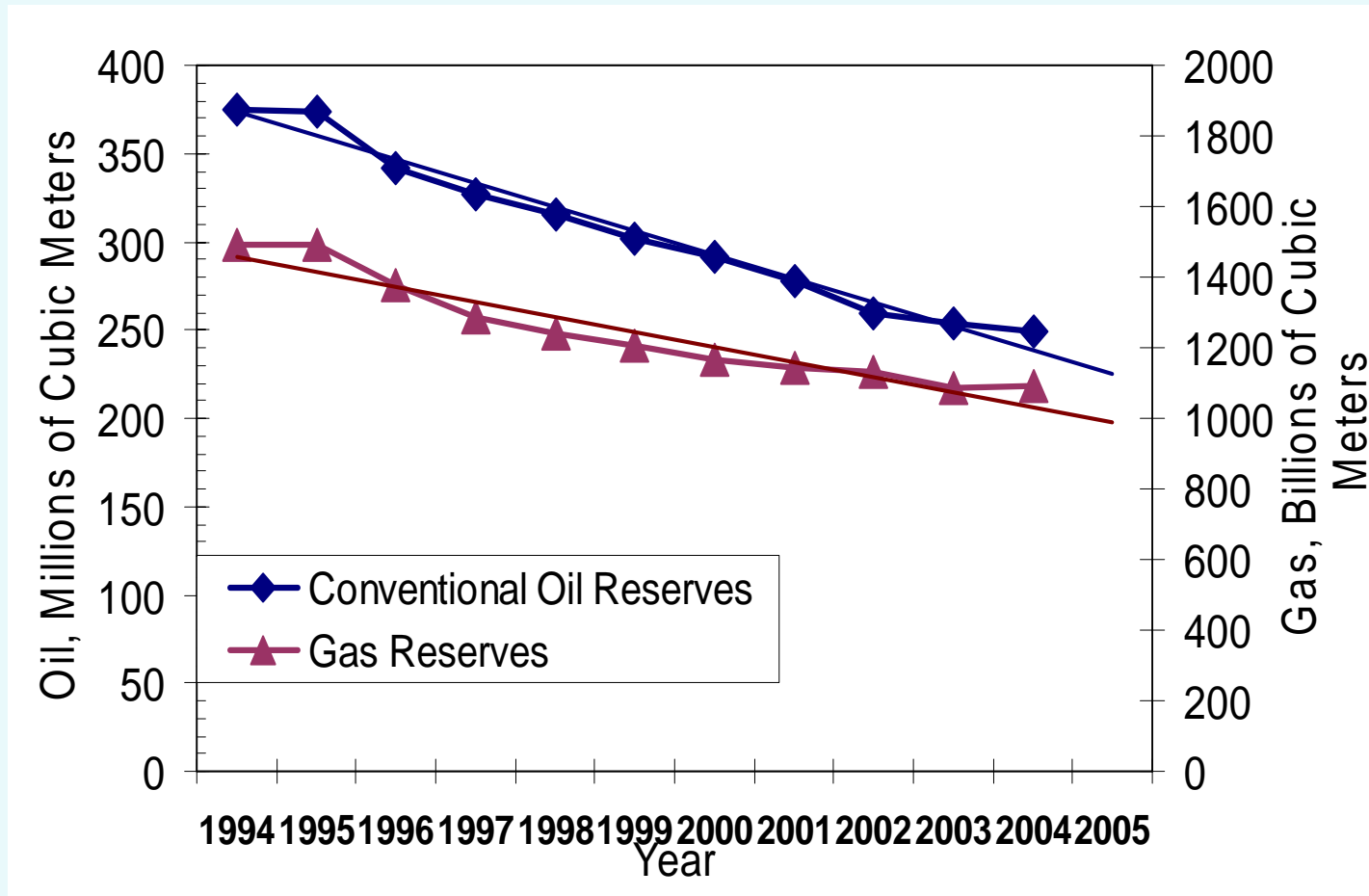
The Size of the Prize

- Primary Production 15% recovery
- Secondary Recovery 30% recovery
- Enhanced Oil Recovery 45% recovery

Outline

- Enhanced Oil Recovery - Current Status
- Alberta Reserves Picture and EOR Contribution
- Where to go from here?
 - IETP
 - Ongoing projects
- Opportunity Areas
 - Improved Water Flooding
 - CO₂ Miscible Flooding
- Example Economic Assessment
- Conclusions

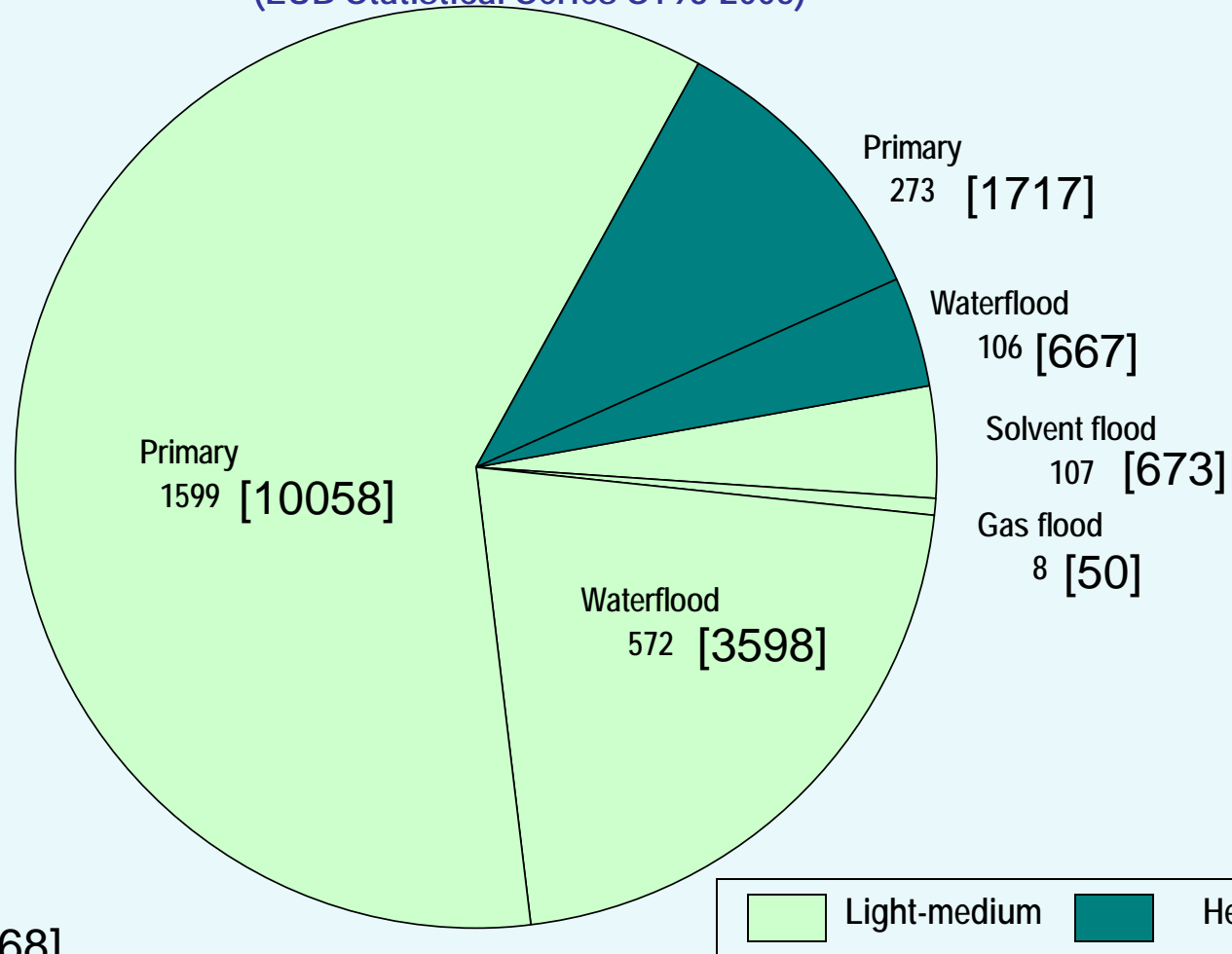
Alberta Conventional Oil and Natural Gas Remaining Reserves



Initial established crude oil reserves by recovery mechanisms

10^6 m^3 [10^6 bbl]

(EUB Statistical Series ST98-2005)



- Initial established reserves [16762]
- <10% remain [1568]

**SMART THINKING.
POWERFUL SOLUTIONS.**

© 2005 Alberta Research Council



Contribution to Alberta's Conventional Oil Reserves Base by Recovery Mechanism (10⁶ bbl)

←----- Initial established reserves ----->

	OOIP	Primary	WF/Gas Flood	Solvent Flood	Total
L&M	P: 23,996	5,454	-	-	5,454
	WF: 18,845	2,774	2,554	-	5,328
	S: 5,850	1,616	1,044	673	3,333
	Gas: 730	214	50	-	264
Heavy	P: 10,020	1,302			1,302
	WF: 3,466	415	667	-	1,082
Total	62,907	11,775	4,315	673	16,763

EUB Statistical Series ST98-2005

70%

26%

4%

100%

Alberta Average Recovery by Mechanism (%OOIP)

(EUB Statistical Series ST98-2005)

	Primary	Waterflood/ Gas	Solvent	Total (rounded)
Light/Medium (L/M) Primary	23	-	-	23
Heavy (H) Primary	13	-	-	13
L/M Waterflood	15	14	-	28
H Waterflood	12	19	-	31
L/M Solvent	28	18	12	57
L/M Gas	29	7	-	36

Current Status

- Much of Alberta conventional oil production is mature, produced at high water-oil-ratios
 - 2003 conventional oil production 37.1 million m³ (233 million bbl)
 - 2003 annual water production incidental to oil production was 535 million m³ (3.4 billion bbl)
 - Public concern about use of water is increasing
 - May impact application of water based EOR processes
- Water handling costs increase with maturity, and need for recycling/disposal
- Reserves are directly impacted by water handling costs

Comparison of Water Handling Costs Alberta vs. World

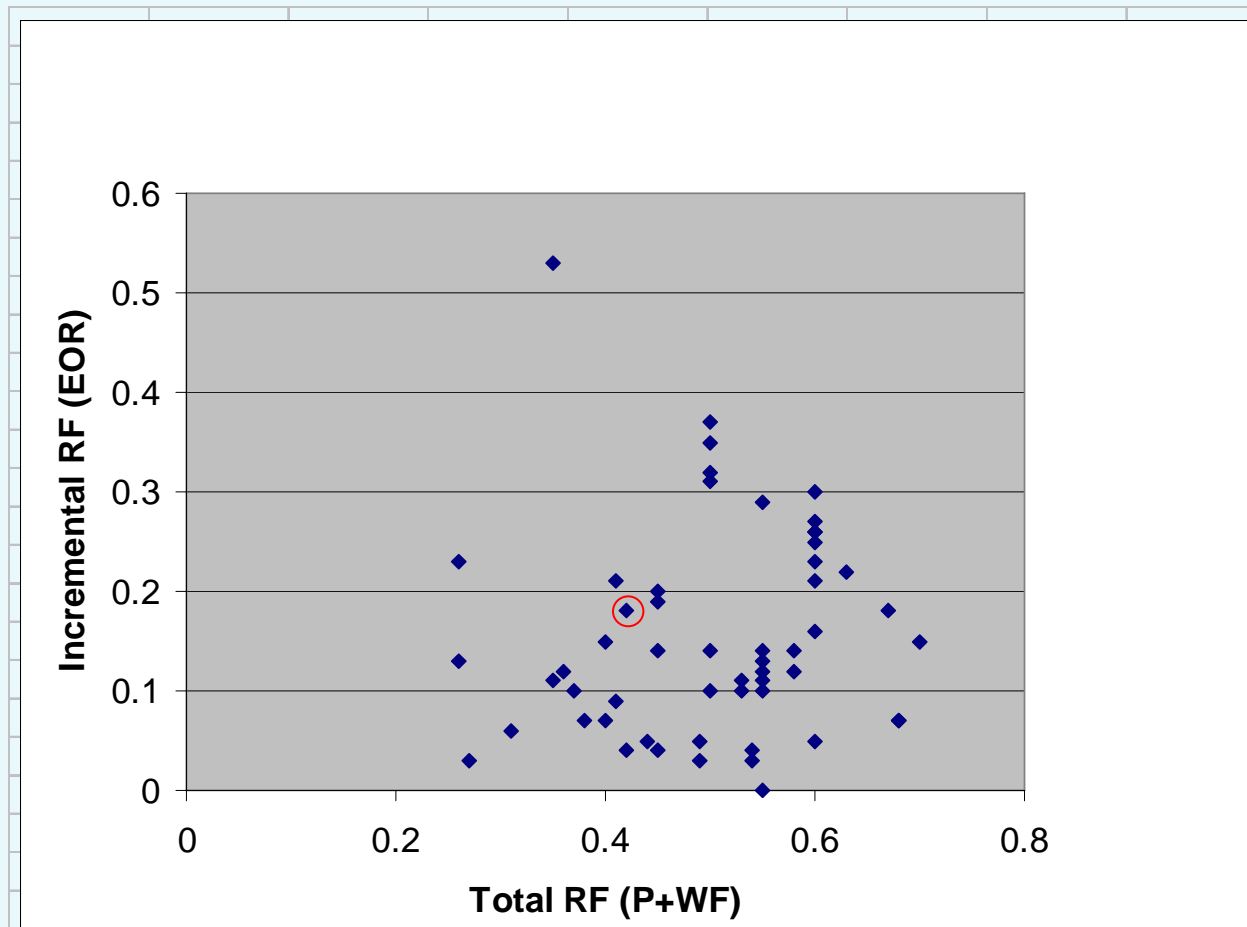
		World	Alberta
Oil Production (million m ³ /d)		13.5	0.10
Water Production (million m ³ /d)		33.8	1.49
Water-Oil-Ratio		2.5	14.9
Cost (million US\$/y)		46,500	1,000
Cost (US\$/m ³ water produced)		3.77	1.84
Cost (US\$/m ³ oil produced)		9.44	27.40
% Operating Costs		30	50

Current Commercial Scale EOR Projects for Conventional Oil

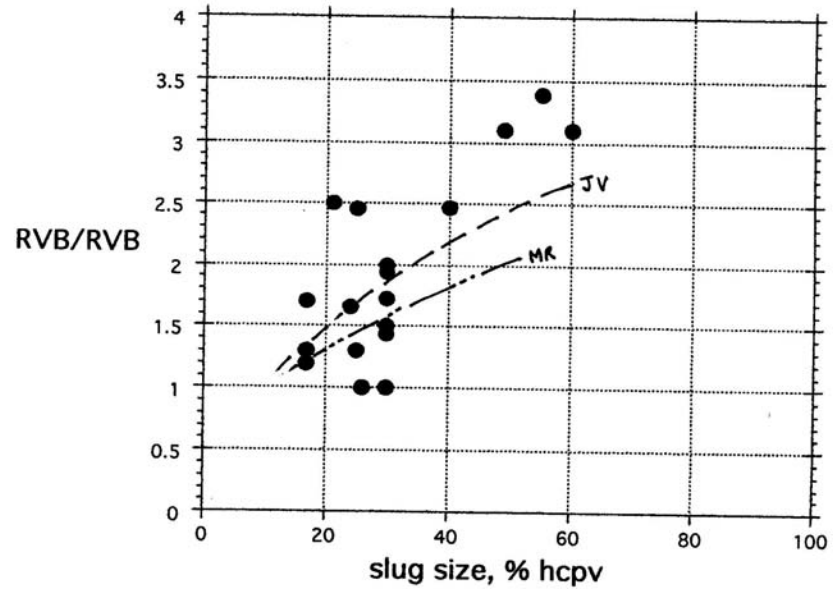
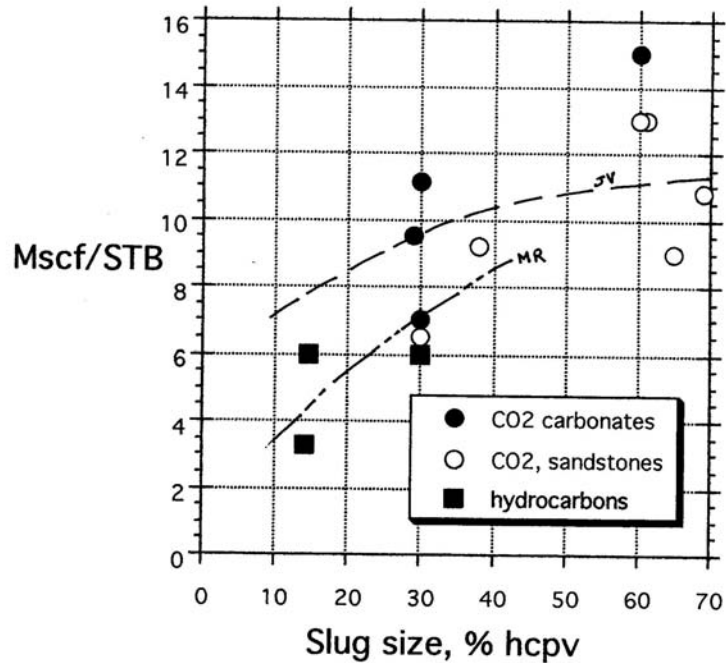
- Commercial EOR projects for conventional oil in Canada are currently dominated by solvent processes
 - HCMF (54 projects in Alberta, 1 in BC; 29 active in 2004)
 - Examples
 - Swan Hills (Devon)
 - South Swan Hills (Penn West)
 - Judy Creek (Pengrowth)
 - Rainbow Keg River (Husky)
 - CO₂ (2 active in Canada in 2004)
 - Joffre Viking (Penn West)
 - Weyburn (Encana)

Alberta Solvent Floods

Incremental EOR Recovery Factor



Gross Utilization Factors for Miscible Solvent Floods



Source: Stalkup

Hydrocarbon Miscible Flooding

No new ones since late 1980s, early 1990s

- Original design usually called for solvent slug injection followed by methane chase gas
- Cost of HC solvent has resulted in replacement in many cases by water chase fluid
- Cost of methane and low molecular weight hydrocarbons mitigates against further implementation

CO₂ Miscible Flooding

- Well established technology, applied extensively in U.S. Permian basin
 - Large natural sources of CO₂
 - Low cost production and compression
- Holds promise for Canada, but...
 - Major CO₂ sources are anthropogenic
 - High cost of compression
 - Need infrastructure to deliver to targets

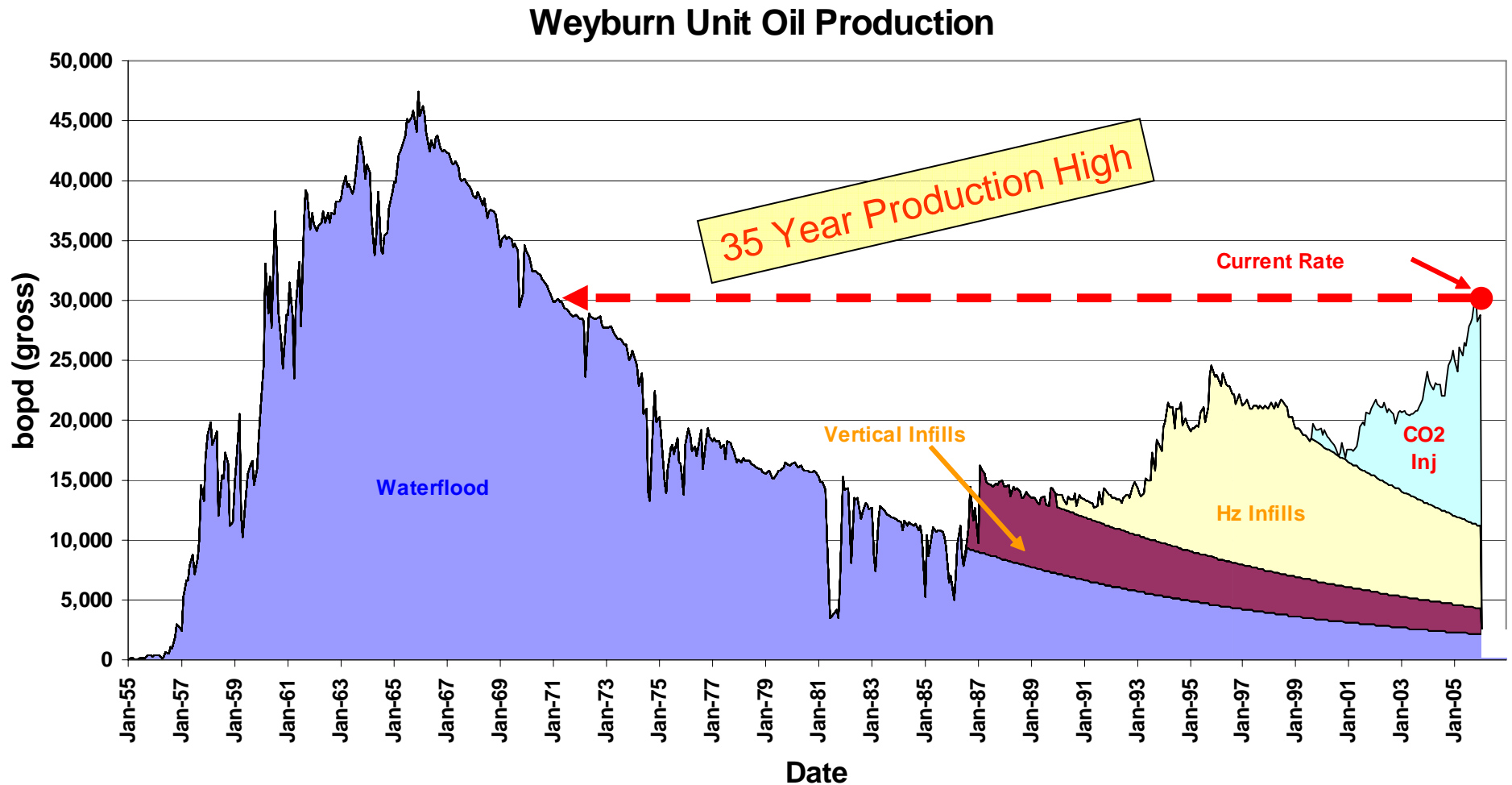
Active CO₂ Flood Statistics [2004 data]

Location	Number	Project kBOPD	EOR kBOPD
World	88 [77]	358 [345]	253 [225]
U.S.	82 [71]	320 [298]	237 [206]
Canada	2 [2]	38 [31]	20 [11]

Source: Oil & Gas Journal, 2006; includes recent production data from Weyburn

Weyburn Unit Historical Production

Courtesy of Encana



SMART THINKING.
POWERFUL SOLUTIONS.

© 2005 Alberta Research Council



Outline

- Enhanced Oil Recovery - Current Status
- Alberta Reserves Picture and EOR Contribution
- **Where to go from here?**
 - IETP
 - Ongoing projects
- Opportunity Areas
 - Improved Water Flooding
 - CO₂ Miscible Flooding
- Example Economic Assessment
- Conclusions

Where do we go from here?

- We need to take an holistic approach to EOR & IOR
 - Reservoir processes (displacement efficiency)
 - Reservoir access
 - Horizontal drilling
 - In-fill drilling
 - Productivity improvement
 - Stimulation
 - Operational
 - Target identification
 - Reservoir characterization

Where do we go from here?

- Improved Waterflooding
 - Conformance control
 - Immiscible WAG
 - Chemical Flooding
- Solvent Flooding
 - Miscible CO₂
 - Immiscible CO₂

Alberta Innovative Energy Technologies Program (IETP)

- \$200 million commitment over five years by Alberta Energy
- Provides royalty adjustments to specific pilot and demonstration projects that use innovative technologies to increase recoveries from existing reserves
- Royalty adjustment of up to a maximum of 30 per cent of approved project costs
- Encourages responsible development of oil, natural gas and *in situ* oil sands reserves.
- www.energy.gov.ab.ca/2858.asp

Alberta Innovative Energy Technologies Program (IETP)

- \$15 million originally provided to CO₂ EOR applications
- Four approved CO₂ EOR projects
 - Anadarko Enchant
 - Apache Zama
 - Devon Swan Hills
 - Penn West Pembina
- Recently approved chemical EOR projects
 - CNRL Britnell polymer flood (\$1 MM)
 - Husky Taber S alkaline-surfactant-polymer flood (\$10 MM)

Outline

- Enhanced Oil Recovery - Current Status
- Alberta Reserves Picture and EOR Contribution
- Where to go from here?
 - IETP
 - Ongoing projects
- **Opportunity Areas**
 - Improved Water Flooding
 - CO₂ Miscible Flooding
- Example Economic Assessment
- Conclusions

Net Injectant Utilization (Rough estimates)

	Injectant Volume / EOR barrel	Cost of injectant	Cost/EOR barrel
H/C Miscible	3-4 mcf/bbl	\$6/mcf	\$18-24
CO2 Miscible	4-5 mcf/bbl	\$2/mcf	\$8-10
CO2 Immiscible	8-10 mcf/bbl	\$2/mcf	\$16-20
Polymer	5-6 bbl/bbl	\$0.7/bbl	\$3-4
ASP	2-3 bbl/bbl	\$1/bbl	\$2-3

Improved Water Flooding Potential

- Polymer Flooding
 - ARC has promoted use of polymer with heavy oils (up to 2000 mPa.s) using horizontal injectors and producers
 - CNRL has received IETP funding for a polymer flood test in the Britnell field (Pelican Lake)
 - We have worked with two other producers who are also testing the process
- Alkaline/Surfactant/Polymer Flooding
 - IETP Funding for Husky's Taber South pilot
 - Planning advanced for large scale application in S. W. Saskatchewan in 2006

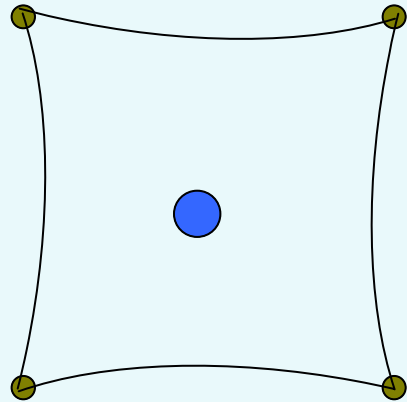
Polymer Flood Applications for Heavy Oil Reservoirs

- Combination of polymer technology with horizontal wells
- Polymer flood can double waterflood recovery in heavy oil reservoirs and reduce water requirements by a factor of 6
- Development requires:
 - Laboratory investigation
 - Numerical Simulations
 - Field Pilots (some actually ongoing)

Waterflooding Technology Development Opportunities

- Alternate water sources and lower water handling costs
 - Dump flooding
 - Produced and waste water treatment and reuse
- Chemical additives for reducing water usage and improving recovery
- Injection of waste/stranded gas in WAG mode to improve sweep

Pattern vs Parallel Horizontal Wells



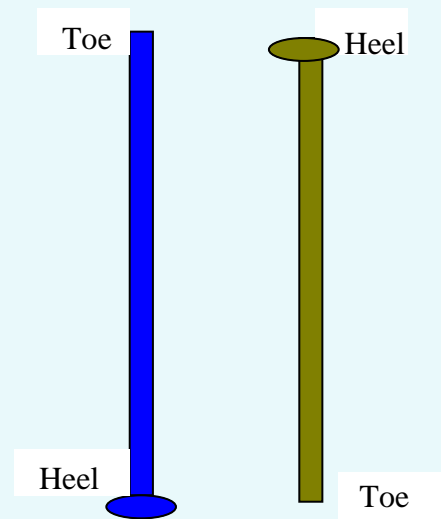
An inverted five-spot showing areal sweep efficiency of about 72%, at break-through. Plan view



Injection well



Production well



"Face-to-face" horizontal well configuration. Plan view
Note: 100% areal sweep (theoretically)



Injection well



Production well

WAG Schemes Using Waste Gases

- Injection of waste (immiscible) gas slugs alternating with water in reservoirs under water flooding may
 - reduce injection water requirements
 - reduce water production
 - improve sweep
- Waste gases could be flue gases, exhaust gases or 'stranded' natural gas occurring within or around the water flood area, that is otherwise uneconomic to conserve

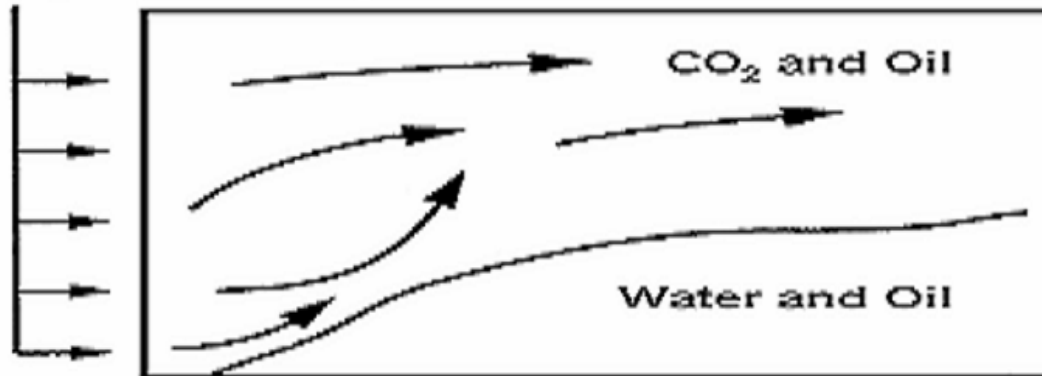
RESULTS OF SUCCESSFUL IMMISCIBLE CO₂ WAG FLOODS

Field	Incremental Oil Recovery*	Daily Oil Prod'n	Incr. Oil Prod'n	CO₂/Incr. Oil
	%OOIP	B/D	B/D	MCF/BBL
Hansford, Marmaton, Tx	9.9	440	440	12
Wilmington, California		1300	500	16.5
Lick Creek, Arkansas	10.1	450	400	8.8
South Marsh Island, Louisiana		220	100	

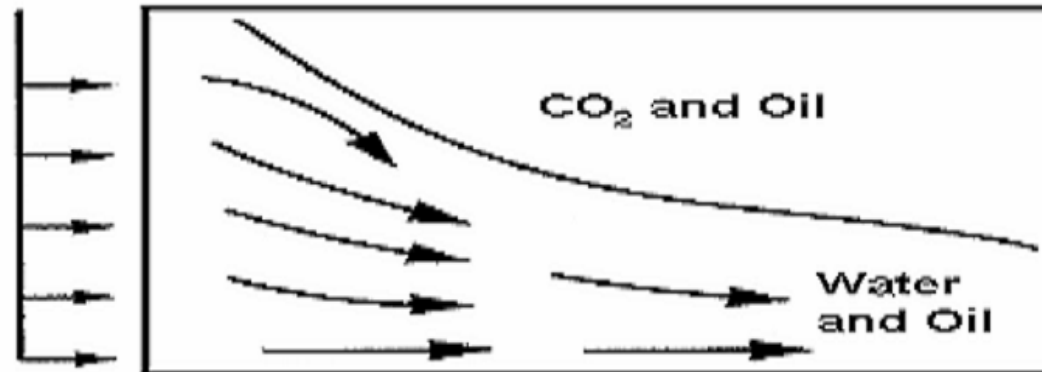
*over primary recovery

WAG Schemes Using Waste Gases

CO₂ Injection Cycle



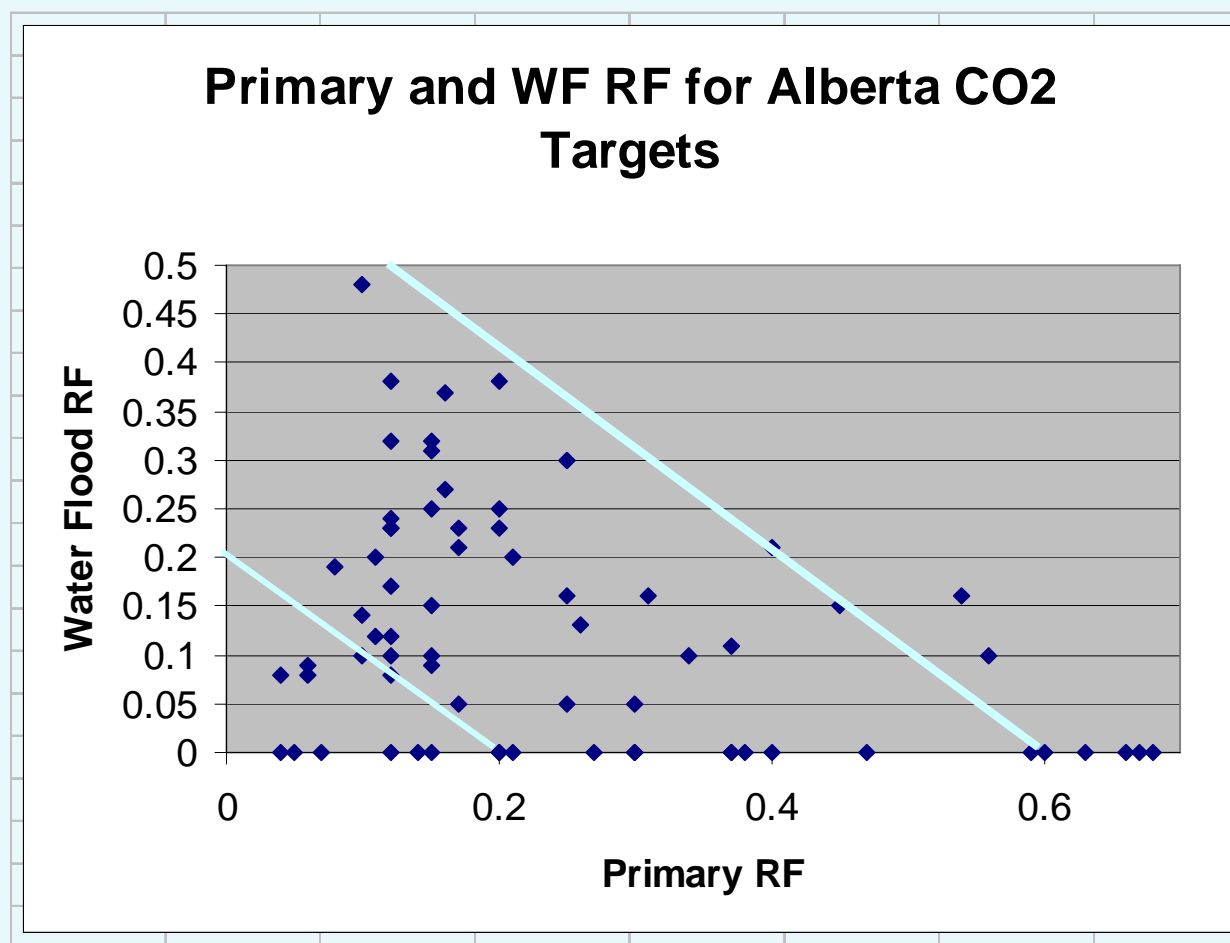
Water Injection Cycle



Challenges to Applying Immiscible WAG

- Adequate gas supply
- Well configuration, completions, wells and facilities
- Corrosion, erosion
- Incremental capital and operating costs
- Determining benefits of incremental oil rates/recovery

CO₂ Prospects in Alberta



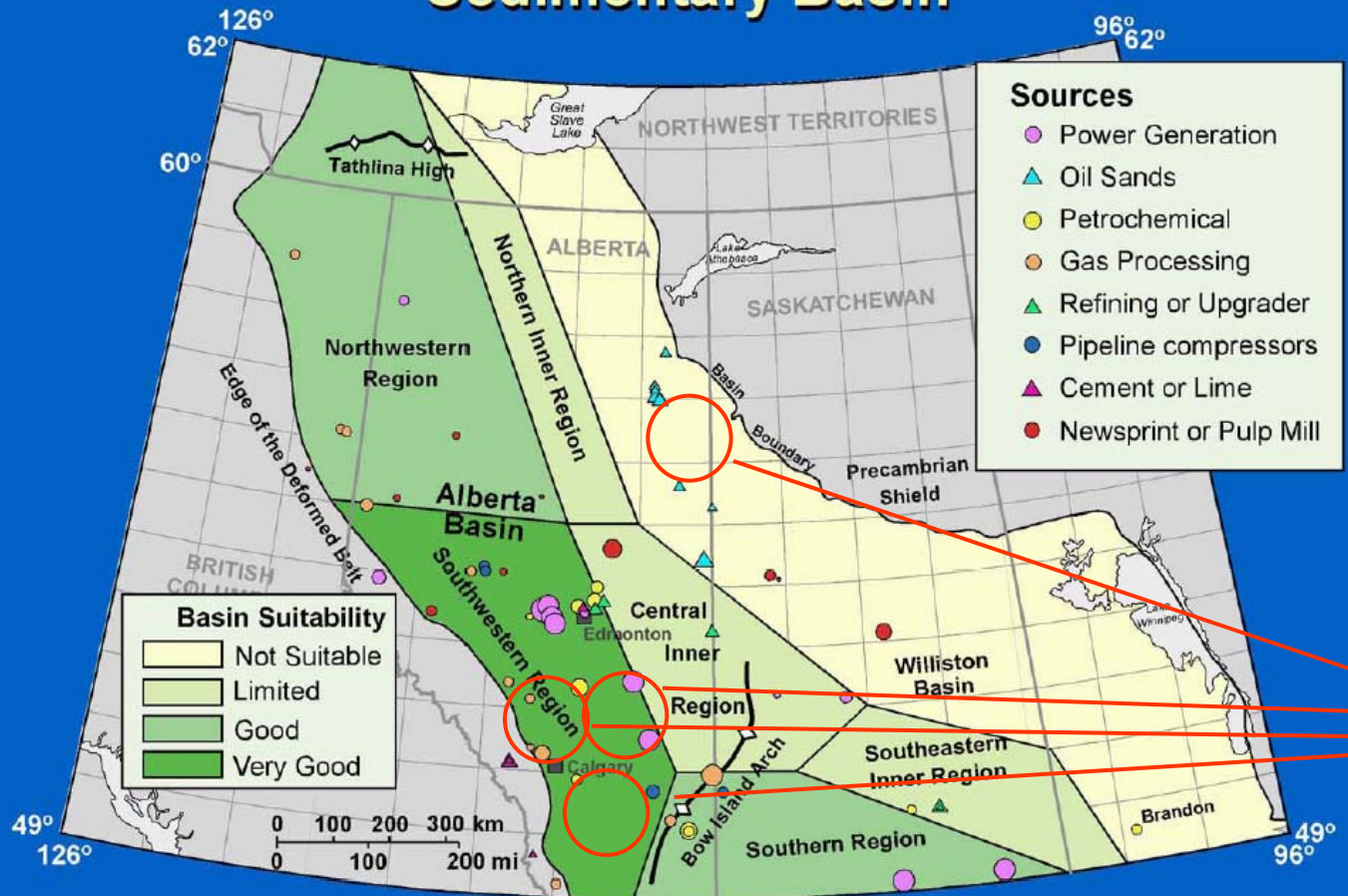
CO₂ EOR Issues

- Aging infrastructure
 - Corrosion
 - Wellbore integrity
- Many reservoirs below MMP
 - Repressurization required
- Economic gap between
 - cost of capture, treatment, transport and
 - acceptable price for EOR application

CO₂ EOR Issues

- CO₂ Supply
 - Remote from EOR targets
 - Requires transportation/compression
- EOR usage alone cannot support large scale transportation infrastructure development
 - Sequestration activities/incentives will help drive development
 - It will take time, maybe 8 to 10 years to build a system

Major CO₂ Sources in the Western Canada Sedimentary Basin



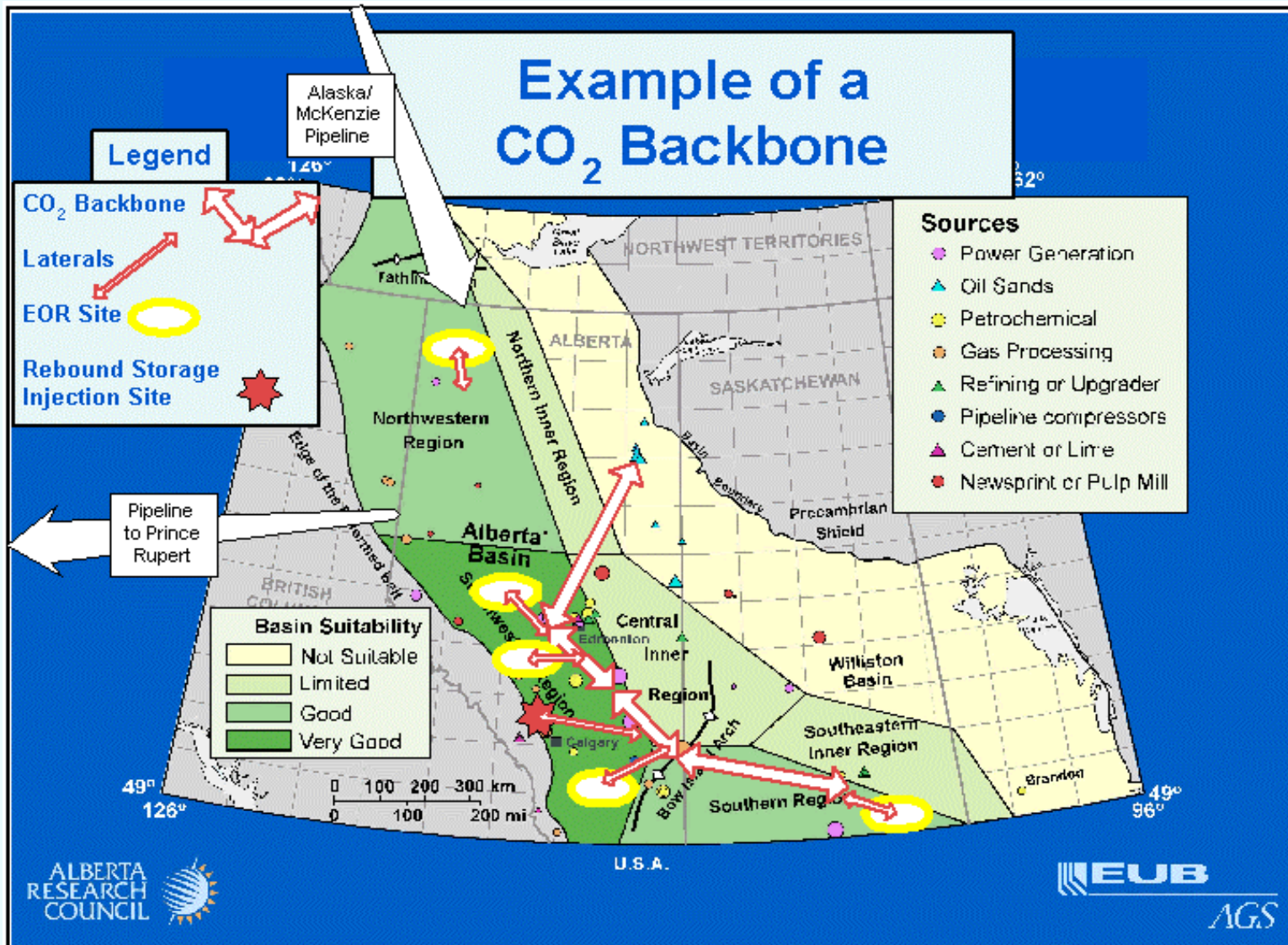
Potential
CO₂
Hubs



SMART THINKING.
POWERFUL SOLUTIONS.

© 2005 Alberta Research Council





**SMART THINKING.
POWERFUL SOLUTIONS.**

© 2005 Alberta Research Council



Outline

- Enhanced Oil Recovery - Current Status
- Alberta Reserves Picture and EOR Contribution
- Where to go from here?
 - IETP
 - Ongoing projects
- Opportunity Areas
 - Improved Water Flooding
 - CO₂ Miscible Flooding
- **Example Economic Assessment**
- Conclusions

Medicine River Example

Medicine River Example

- Several mature water floods in Ferrier/ Medicine River/ Gilby/ Sylvan Lake area
 - Total OOIP of about 250 million m³ (~1.6 Bbbl)
- Generally pressure maintained (above MMP), mature (high water-cut); remaining oil > 70%
- Tight carbonate reservoirs/medium gravity oil

Medicine River Example

Study included

- Prototype Selection
- Sampling and Laboratory Testing
- Simulation: History Match and Predictions
- Economic Evaluation
 - Gas Supply Assessment
 - Facilities Assessment
 - Economic Evaluation
- Sequestration Assessment

Medicine River Example Laboratory Testing

- Oil samples tested for miscibility with CO₂
- Miscibility pressure was less than the current pressures
- Acceptable CO₂ solvent can contain up to 15% methane, or 5% nitrogen

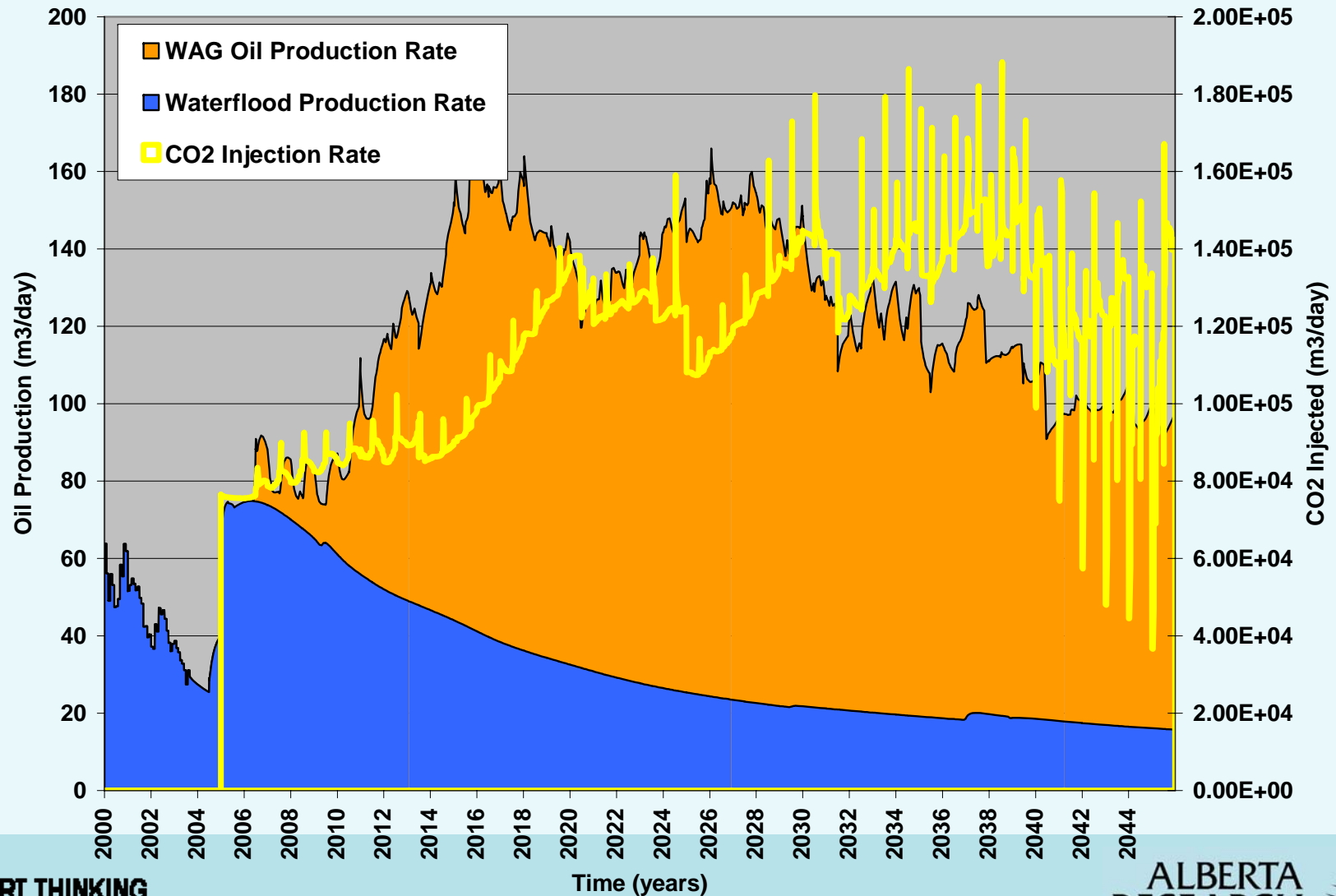
Medicine River Example Gas Supply Assessment

- 2.75 MMcf/d (150 t/d) CO₂ available from Gas Plants in the vicinity of the prototype
- Capex at the plants \$3.8MM and another \$3.8MM for delivery (including pipeline)
- Supply price (arms length transaction) will be \$2.00/Mcf for source and \$1.30/Mcf for recycle CO₂.
 - Alternately, the operator can pay for Capex (\$7.5 MM) and associated operating costs.

Medicine River Example Facilities Assessment

- Capex of \$3.9MM required for facilities upgrades, well recompletions, tubing replacements, new injector tie-in, CO₂ lines, flow lines.
- CO₂ field (injection) compressor will cost another \$1.1MM

Predicted Oil Production for Medicine River



**SMART THINKING.
POWERFUL SOLUTIONS.**

© 2005 Alberta Research Council

**ALBERTA
RESEARCH
COUNCIL**



	Base EOR	Base – 25% INCREMENTAL Recovery	Base+ Infill	Base with Double CO₂
Oil Production (E3m3)	1430.7	1073.0	1216.7	1442.9
Capex MM\$	12.9	12.9	27.7	15.6
Opex MM\$	138.6	124.2	107.6	138.5
Gross Revenue	411.1	308.4	317.8	368.6 MM\$
Net Revenue	239.0	155.8	166.5	196.0 MM\$
NPV 10%	35.0	20.1	35.7	73.6 MM\$
P/I (Undisc.)	16.61	10.16	5.21	10.84
Payout in years (undiscounted)	7.3	9.1	7.1	4.0
Payout@10% (years)	9.2	11.6	9.2	5.0

Medicine River Example Results

- Reasonable economic indicators (15 to 30%) DCF-ROR
- Long payout periods (5 to 12 years discounted @ 10%, but could be further optimized)
- Sensitivity to capital and operating costs including CO₂ supply cost and volumes
- Infill drilling feasible but little impact on NPV or Payout Period

Medicine River Example Sequestration Assessment

- At the prototype, 2.75 MMcf/d net CO₂ injection (about 1 Bcf/Year) for 40 years, upwards of 40 Bcf or 2.2 million Tonnes of CO₂ can be stored in the Unit
- Within the region, potential to add reserves by upwards of 200 MMB and sequester about 40 MMT CO₂
- Incentives for these need to be explicitly identified in economic evaluations
- For incremental oil recovery of 8.8 MMB at the prototype, this corresponds to 4.5 Mcf/B [Cost~\$9/B].

Medicine River Example

Barriers to CO₂-EOR

- Long payout periods; Limited CO₂ available
- Insufficient CO₂ infrastructure is the main cause behind these
- CO₂ supply prices at the field gate need to become more affordable
- Limited window of opportunity, logistics (internal and external) and long lead times for negotiations/EOR implementation

Concluding Remarks

- Good potential for EOR to add reserves, especially in concert with other complementary technologies
- Economics for each process/target need to be assessed independently
- Delivery infrastructure for CO₂ is needed for CO₂ flooding to make an impact
 - Storage/sequestration needs may support this development
- EOR contribution will be impacted by water management issues
- Technology development opportunities exist to improve efficiency and reduce costs

Acknowledgments

- Alberta Energy Research Institute
- Alberta Research Council
- Acclaim Energy
- ARC Resources
- ConocoPhillips
- Keyera Energy

- Ashok Singhal
- Alex Turta
- Fred Wassmuth