Secondary and Tertiary Recovery From Tight Oil Reservoirs

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Outline

- Summary
- Why do we need to look at tight oil waterfloods?
  - Review of primary production type curve
- Time to unlearn conventional waterflooding – new mental model
- What factors are critical to evaluating waterflood feasibility in tight reservoirs?
- Injection – manage carefully
- WF Bakken Case Study
- CO2 injection in Tight Oil Waterfloods
- WAG (miscible CO2) Bakken Case Study
- Conclusions
Summary – Production Profile

• Typical horizontal wells with hydraulically induced fractures are averaging ~24m$^3$/d but with steep decline (Pembina Cardium/Bakken/Montney)

• Initial production rates are affected by completion efficiency, near wellbore permeability

• Thus, these reservoirs are going to need secondary support

• **Waterflooding** should provide 50 – 100% of primary recovery in additional reserves
Summary – Sensitivity Analysis

- Changing matrix permeability resulted in the biggest variance between oil rates (1mD – 10mD)
- When fractures are long enough to link up, waterflooding still yields incremental oil, but at the expense of higher water production
- Matrix/Fracture crossflow is the limiting factor
- Establishing a primary production baseline is key for economic analysis (and quantifying waterflood benefit) – fluid properties (solution gas/bubble point pressure) are key
Typical Oil Production Profile on Primary Production

Tight Oil Formations in WCSB

- Initial inflow performance ranging from 15-25 m3/d
- Note peak oil rate is very short lived (65% drop off in oil rate within 100 days)
- Stabilized rate is ~ 5m3/d

- Usually low solution gas volumes dissolved in these oils → Pressure drops very quickly!
- Reservoir losing drive energy fast → need for additional energy to optimize reservoir performance
- Primary recovery factors in the 6-12% range
Pembina Cardium Reservoir Properties

- Discovered in the 1950’s, first oil in 1957
- Clastic play in muddy/silt/sandy shore-face shelf,
- Over 11,500 wells drilled to date
- OOIP>8 billion bbl
- 17% Recovery Factor to date from primary and waterflood,
- Abundant cores and multiple vintage log suites

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>12%</td>
</tr>
<tr>
<td>Water saturation</td>
<td>11%</td>
</tr>
<tr>
<td>Range of permeability</td>
<td>0.1 mD – 100 mD</td>
</tr>
<tr>
<td>Area of interest permeability</td>
<td>0.1 mD – 5 mD</td>
</tr>
<tr>
<td>Oil Gravity</td>
<td>38.1 API</td>
</tr>
<tr>
<td>Depth</td>
<td>1200 m – 2800 m</td>
</tr>
</tbody>
</table>
*** Wells scattered throughout Pembina Cardium
Oil Rate for the 81 Pembina Cardium Multi-Frac'd Wells

~65% decline rate in first year, shallow decline after that

Initial rates show large scatter but similar decline trend
Decline rate is steep ~65%/yr in first year, generally caused by:
- Transient effects
- Pressure depletion
- Increasing gas saturation

Secondary recovery will become critical to maintain a higher plateau oil rate
- Lack of drive energy
Solution Gas Ratio/Bubble Point – Primary Depletion

- Low solution gas/low bubble point – little drive energy (rock, liquid)
  - Rapid production decline resulting in low primary recovery
  - Waterflood effect more pronounced
- High solution gas/bubble point – liberation of gas below bubble point -> gas expansion provides drive energy and cushions pressure drop
  - Waterflood will have to overcome gas voidage
Mental Model: Waterflood Response

Conventional Waterflood

Tight Oil Waterflood

Oil rate vs. time for Conventional Waterflood and Tight Oil Waterflood.

Start of injection
Model Description (Waterflood Base Case)
Model Description

Typical Pembina Cardium Reservoir Parameters

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid Dimensions</td>
<td>83 x 80 x 15 gridblocks</td>
</tr>
<tr>
<td>Grid block Dimensions</td>
<td>20m x 20m x 1m</td>
</tr>
<tr>
<td>Porosity</td>
<td>12%</td>
</tr>
<tr>
<td>Oil Gravity</td>
<td>38.1 API</td>
</tr>
<tr>
<td>Net-to-Gross Ratio</td>
<td>0.4</td>
</tr>
<tr>
<td>Mobility Ratio</td>
<td>1.09</td>
</tr>
<tr>
<td>Initial Pressure</td>
<td>20.3 MPa</td>
</tr>
</tbody>
</table>

- Fractures are put in through all K-Layers (15 Layers ~ 6 m)
- Injecting BHP constraint at 27 MPa
- Producing on BHP constraint of 5 Mpa
- **Start injection on day 1**
- Forecasts run for 30 years
Sensitivity to Matrix Permeability

Description:

– Fracture Half Length: 100 m
– Fracture Spacing: 100 m
– Well Spacing: 400 m
  • ~4 wells / section
– Fracture Conductivity: 2
  • Results in a transmissibility multiplier of 11
– Variable: Matrix Permeability
  • Case 1: 0.01 mD
  • Case 2: 0.1 mD
  • Case 3: 1.0 mD
  • Case 4: 10 mD
Cumulative Oil Production – Matrix Perm

Cumulative Produced Oil Comparison

Matrix Perm – 0.01 mD
Matrix Perm – 0.1 mD
Matrix Perm – 1 mD
Matrix Perm – 10 mD
RF vs. HCPVI – Matrix Perm

Basically same process but very large differences in throughput rates
Reservoir Pressure – Cases 1 - 4

Note long transient pressure stabilization period for low permeability cases.
Sensitivity to Fracture Half Length

Description:
- Fracture Spacing: 100 m
- Matrix Permeability: 1 mD
- Well Spacing: 400 m
- Frac Conductivity: 2
- **Variable: Fracture Half Length**
  - Case 5: 60 m
  - Case 6: 140 m
  - Case 7: 180 m
  - Case 8: 200 m (Touching Fracs)
Cumulative Oil Production – Fracture Half Length

Fracture Half-Length – 80 m
Fracture Half-Length – 140 m
Fracture Half-Length – 180 m
Fracture Half-Length – 200 m
RF vs. HCPVI - Fracture Half Length

Now different process depending upon fracture length

Fracture Half-Length – 80 m
Fracture Half-Length – 140 m
Fracture Half-Length – 180 m
Fracture Half-Length – 200 m
Cumulative Water Production – Fracture Half Length

Cumulative Produced Water Comparison

Fracture Half-Length – 60 m
Fracture Half-Length – 140 m
Fracture Half-Length – 180 m
Fracture Half-Length – 200 m
Sensitivity to Fracture Spacing

Description:
- Matrix Permeability: 1 mD
- Well Spacing: 400 m
- Fracture Half Length: 100 m
- Fracture Conductivity: 2

- **Variable: Fracture Spacing**
  - Case 17: 60 m
  - Case 18: 140 m
  - Case 19: 200 m
  - Case 20 has the above parameters with a fracture spacing of 100 m and no water injection
Cumulative Oil Production – Fracture Spacing

Fracture Spacing – 60m
Fracture Spacing – 140m
Fracture Spacing – 200m
Fracture Spacing – 100m w/o wtr
Watch your Voidage Replacement Ratio and Injection Pressures

• Main issue is low perm…low inj
• Compensate with higher inj. pressure?
  NO
  – High injection rates will lead to higher pressure which will extend hydraulic fractures (short term gain long term loss)

➢ Higher inj/prd ratio (1:1)

Need to understand your Reservoir to optimize fracture Lengths and injection rates
However, Minifracs do not provide us with Stress Orientation.
Case Study – Bakken Waterflood Project

• Completed 11 analytical and reservoir simulation studies on Bakken properties

• Typical Bakken Reservoir Parameters:
  – Very Light Oils (°API range of 36-42) that can be efficiently waterflooded due to favourable mobility ratios
  – Initial Pressures of about 9500 kPa
  – Bubble Point pressures ranging from 2200-3300 kPa
  – Very low solution GORs (4-8 m3/m3) → basically dead oils with little drive energy
  – Average thickness of ~5-6m
  – Low permeability (0.5-5mD)...south of border even lower permeability
  – Primary RFs of 6-13% (depending on spacing)
  – WF provides an additional 50-100% reserves. Injectivity is key issue.
  – Lodgepole water bearing formation above zone (risk of fracturing and creating communication)
Case Study – Bakken Waterflood Project

- Bakken Pool with ~800 wells drilled
- Production began in 2002 with mainly vertical wells
- 16 vertical wells per section
- Availability of ample log and core data allowed for detailed static geomodel construction
- Waterflood pilot was first started in 2006 using vertical injectors.
- Due to injectivity issues → decision was made to move to horizontal injection
- Placing up to 4 horizontal injectors per section (1600m long) in between vertical wells
- CO2 pilot started…confidential – initial results not in public database
Case Study – Producers – Vertical vs. Horizontal

Horizontal producers
Peak ~ 130 bbl/day
Plateau ~ 45 bbl/day

Vertical Producers
Peak ~ 60 bbl/day
Plateau ~ 7 bbl/day
Case Study – Injectors: Vertical vs. Horizontal

Horizontal injectors ~175 bbl/day

Vertical injectors ~30 bbl/day

Throughput is the main issue in tight oil waterfloods!!!
Case Study – Pressure Data

- Shows all publicly available pressure data for entire pool
- Initial Pressure ~ 9500 Kpa and Bubble Point ~ 2200 Kpa
- Note that due to low solution GOR pressure depletes very quickly. Within two years, reservoir pressure has dropped to bubble point pressure
- Losing productivity fast
- Pressure decline follows Liquid and Rock Expansion drive due to low solution GOR --- behaves almost as a dead oil
- Shows importance of injecting water early in production life of reservoir.
Case Study – Reservoir Simulation

- Static 3D geological model
  - Input Mapping, log data, core data
  - Output detailed 3D model containing tops of zones, porosity, water saturations, and permeability

- 3D Dynamic Flow Simulation
  - Upscale Static Model for Simulation
  - Well locations, deviation surveys, perforation, prod/inj data
  - PVT and Relative Permeability Data (how is the fluid going to move? How will pressure changes effect the fluid)
  - History Match production characteristics
  - Use model as forecast tool – test scenarios involving spacing, frac's, water injection, etc……
Case Study – Pilot Area History Match

Water Inj. Starts at 1000 days (~ 3 yrs)

(Note change in oil rate decline upon start of WF)...waterflood response for tight oil pools is more subtle

Infill drilling
Case Study – Pilot Area Waterflood Response

**Recovery Factor** = \( E_d \cdot E_v \)

- **\( E_d \)** = microscopic displacement efficiency
  \[ \frac{S_{oi} - S_{orw}}{S_{oi}} \]

- **\( E_v \)** = macroscopic displacement efficiency

\[ \frac{70\% - 30\%}{70\%} = 57\% \]

Maximum Recovery from this Bakken play if all oil is fully swept by water.

Good Performing Waterfloods have 70-80\% \( E_v \)

If optimized efficiently, due to high API gravity of the bakken fluid we expect an effective flood with piston like displacement (favorable mobility ratio) resulting in high volumetric sweep efficiencies

...main Issue is getting water into the reservoir in a reasonable amount of time (economically viable?)
Case Study – Pilot Area Waterflood Response

**Vertical Injector – Saturations vs Time**

Cross section through the Bakken Model showing an injector-producer well pair.

Piston like displacement occurring during the waterflood.

Water is effectively displacing oil to the producer.
Pressures in the primary production area are around 2000 kPa or less.

In the pilot waterflood area, we are seeing much higher pressures → 5000-6000 Kpa range.

It’s due to pressure maintenance and sweep that the decline in the pilot area is shallower..
Case Study – Pilot Area - RF vs. HCPVI

- Current Actual Field Results (Public Data):
  - Years on WF = 4
  - HCPVI = 0.12
  - HCPVI/yr = 3%
  - Current RF = 10% OOIP

- 30 year Forecast:
  - HCPVI = 0.8
  - RFult = 32% OOIP

* Note – performing decline on sections producing on primary production results in ultimate RFs ranging from 6-13% OOIP (depending on spacing)
Case Study – How does the actual field data compare to the Box Model?

- Uniform Box model appears to be a more efficient waterflood (homogeneous model)

- Bakken Field Case study RF vs. HCPVI breaks over quicker indicating it is a less efficient waterflood → more realistic due to heterogeneity…..

RF vs. HCPVI – Matrix Perm

Cases 1 - 4

Matrix Perm – 0.01 mD
Matrix Perm – 0.1 mD
Matrix Perm – 1 mD
Matrix Perm – 10 mD

Simulation Section 9
Current Section 9
Alberta’s 2008 Climate Change Strategy

Alberta has committed to reducing projected emissions by half by 2050 (200 Mt)

70% of this reduction will be achieved through CCS (139 Mt in reductions)

Oil sands are a large contributor to CO₂ emissions
- By 2017 crude bitumen production is expected to triple to 3.2 BSTB/d and expenditure related to oil sands to reach $116 billion
- w/o CCS green house gases emitted from oil sands would more than DOUBLE!

Source: Alberta 2008 Climate Change Strategy
Technical Benefits of CO$_2$

- Miscible at lower pressures than nitrogen or methane
- Some impurities will lower the minimum miscibility pressure (MMP)
- Density is closer to reservoir fluids (oil/water) compared to other gas floods
  - Favorable mobility ratio = better sweep efficiency
  - Less over-ride during horizontal flooding
Incremental Recovery Factor Estimation

- Quick Analytical Method
- Waterflood Volumetric Sweep Efficiency
- A good waterflood is more likely to be a good candidate for CO$_2$ EOR
- Rule of thumb waterflood ultimate recovery factor URF>$25\%$ OOIP

$Ed = \text{displacement efficiency (property of the rock)}$

$E_{dw} = \frac{(S_{oi} - S_{orw})}{S_{oi}}$

$Ev = \text{volumetric sweep efficiency}$

- Successful WF in WCSB have $Ev \sim 75\%-80\%$

Estimating Volumetric Sweep Efficiency

$Recovery = E_{vol} \cdot E_d$
What type of incremental RFs can I expect?

- Shows incremental RF for mature CO2 and WAG floods Canada/US
- On average, incremental RF ~ 10-12%
- Do we expect to see this good of an incremental in tight oil reservoirs?

SPE paper 35391, SPE monograph Stalkup, SPE paper 26391, and Epic's interpretation
Case Study: Bakken CO₂ Injection
# Bakken Example - CO₂ Screening Criteria?

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Criteria</th>
<th>Bakken Example</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir depth</td>
<td>&gt; 2500 – 3000 ft</td>
<td>5140 – 5300 ft</td>
</tr>
<tr>
<td>Oil Viscosity</td>
<td>&lt; 10 – 12 cp</td>
<td>0.47 - 0.5 cp</td>
</tr>
<tr>
<td>Oil Gravity</td>
<td>25 – 36 degrees API</td>
<td>~ 44</td>
</tr>
<tr>
<td>Current Oil Saturation</td>
<td>&gt; 20% Pore Volume</td>
<td>52% - 53%</td>
</tr>
<tr>
<td>Reservoir Temperature</td>
<td>&lt; 190 Degrees F</td>
<td>157°F</td>
</tr>
<tr>
<td>Current Reservoir Pressure</td>
<td>&gt; Minimum Miscibility Pressure</td>
<td>~ 9700 kPa (potentially lower)</td>
</tr>
<tr>
<td>Gas Cap</td>
<td>No Gas Cap</td>
<td>No Gas Cap</td>
</tr>
<tr>
<td>Fractures</td>
<td>No Fractures</td>
<td>Hydraulic Fractures</td>
</tr>
<tr>
<td>Waterflood Response</td>
<td>Good response</td>
<td>Immature</td>
</tr>
</tbody>
</table>
Well Layout – 4 multi-stage horiz frac wells per section

32 Section map (Red) with 9 Sections highlighted (green) and Block 10 (Blue)
Bakken Example - Oil Forecast Comparison

Base Case Waterflood – Blue RF = 21%
CO2 – Pink – 5% Incremental Oil, RF = 26%
WAG – Red – 8% Incremental Oil, RF = 29%
Conclusions

• Multistage wells are proving to be very successful for tight oil reservoirs (primary RFs in the 6-12% range)
• Secondary/Tertiary recovery is becoming essential to recovery maximum potential from these reservoirs
• From field and simulation experience waterflooding tight oil reservoirs should close to double primary RF. RF~15-25%
• CO2 miscible injection also proving to be favourable in field and simulation results. Providing additional 5-7% RF on top of WF
Fracture Conductivity

Method:

\[ F_{CD} = \frac{k_f w_f}{k x_f} \]

\[ k_f = \frac{F_{CD} k x_f}{w_f} \]

\[ k_{avg} \Delta x = k_f w_f + k(\Delta x - w_f) \]

\[ k_{avg} = k \left[ \frac{F_{CD} x_f}{w_f \Delta x} \frac{w_f}{w_f} + \frac{(\Delta x - w_f)}{\Delta x} \right]^{0} \]

where:
- \( F_{cd} \) – Fracture Conductivity
- \( k_f \) – fracture permeability
- \( x_f \) – fracture half length
- \( w_f \) – fracture width
- \( k \) – matrix permeability
- \( \Delta x \) – grid block width
- \( k_{avg} \) – average permeability in frac’ed gridblock

Permeability multiplier in frac’ed grid block governed by this term