Horizontal Well Completions

• Objectives
  – To provide a clear, applications oriented view of horizontal well completions and workovers.
  – To enable the class participant to design an effective horizontal well completion.
    What data to collect and why it is important
    How to select a candidate
    What computer models to use / Who can help
    What completion is probable, possible and practical
    What to expect on production / How to operate it
    How to design it.
Horizontal Wells

• First conceived in US and USSR in 1930’s
• First serious attempts in 1950’s
• First successful completions in 1970’s
• Caught on world-wide in 1980’s
• Now a standard well configuration
The start of the current era - extended reach well records at start of the year 2000

Slide modified from BP
Uses of Horizontal Wells

• increasing reservoir contact
• water/gas coning control
• water/steam injection
• extended reach capability
• minimizing surface locations, slot saving
• improving wellbore location
• prospecting and gathering reservoir info.
• drain individual compartments
Other Uses

- Prospecting - as a tool to prove up seismic in an area
- Accessing all parts of the field - flank wells a favorite in offshore reservoirs
- As a platform for fracturing
- As a “gathering system” - Amoco Canada’s “Big Kahuna”
Favorite Targets

- Naturally fractured chalks and shales
- Water coning problem areas
- Field edges
BestCandidatesfromaReservoirPerspective

• 1. Must still have good volume of reserves, pressure and fluids of value.

• 2. Permeability values (horizontal and vertical) more a design consideration than a limit.

• 3. Oil was thought to be a better candidate than gas because of hydraulic fracturing, however, horizontal wells with multistage fracturing are a common completion for low permeability gas plays.
Best - non stimulated candidates

- No vertical barriers and generally high permeability reservoirs.
- $K_v/K_h > 0.1$ to $0.5$ (opinion) (consider frac if perm is too low)
- Natural fractures often viewed as “good”, but watch effects on the drainage profile and also bottom water.
Red Flags - for unstimulated horizontals

- Poor quality reservoirs - need something to start with.
- Very low Kv, vertical flow barriers
- Some extremely thick zones
Reservoir Considerations

• Will reduced footprint help? (offshore and high land cost or political areas)
• Will there be improvements in contact with some dipping beds.
• Pay configuration issues:
  – layers
  – boundries
  – anisotrophy
Permeability Variance

• $K_h$, $K_H$, $K_v$
• Barriers
• Bed angle (a vertical well can be horizontal to the bedding plane in some instances)
Directional Permeability

$K_V$

$K_{H_{90}}$

$K_H$
Permeability Contribution from Vertical and Horizontal Permeability

Horizontal Wellbore

Vertical Wellbore
Drainage in a Horizontal Well for Cases of Permeability Anisotrophy

\[ \frac{K_V}{K_H} = 0.1 \]

Wellbore \hspace{2cm} Zone of drainage

\[ \frac{K_V}{K_H} = 1 \]

\[ \frac{K_V}{K_H} = 2 \]
Placement of the Horizontal Above the O/W Contact

• Depends on:
  – vertical permeability
  – fluid viscosities
  – pay zone thickness
  – anomalies in the zone
  – depth (?) and formations above the pay zone
Pay Zone Thickness

- no minimum or optimum
- vertical and horizontal permeability more critical
  - fractures
    - incidence of fractures
    - location of fractures
    - permeability of fractures
    - good or bad? - water???
When is a Multi-lateral Required?

• Wherever compartmentalization reduces the ability of a single wellbore (stimulation?) to effectively and economically drain the reservoir.
Stacked and Opposed

Stacked and opposed lateral
Compartment Recognition

- Geological clues
- DST’s
- Production behavior
- Hydrocarbon source variances (oil fingerprinting)

- Early Recognition - addressed in design
- Later Recognition - requires a workover
A two flow period test of reservoir potential – what does it tell?

Information available from downhole gauges and flow tests.
• Reservoir pressure
• Perm estimates
• Depletion
• Barriers
• Damage
• Compartmentalization
Recognizing Compartmentalization

TWO ZONE EFFECT
Two entirely different producing zones exposed in a test interval
One zone has higher reservoir pressure or better permeability
Fair permeability

Slide from George Tews
Horizontal Well Expectations

• Uncertainty???
  – can it be drilled?
  – can it be completed?
  – can it be operated/produced?
  – is it really a good candidate?
  – is fracturing needed?
Horizontal and Lateral Drilling

• An introduction to horizontal well drilling technology:
  – Goal is to make the engineer/foreman aware of some problems and solutions available in drilling operations that can have a major effect on completions and production.
Types of Horizontal Kick-Off designs.
Increasing the angle limits weight transfer to the bit.

Long radius wells at 2 to 6° are used for extended reach.

Medium radius wells at 6 to 8° minimize drilling but lose some extension capacity.

Short radius wells over 8 to 10° can miss problem zones above the pay, but are short.
Ability to Lift Cuttings

• Must reach high enough velocities to carry particles upward.
  – Problems in horizontals:
    • limited circulation rate
    • large annular areas = low flow velocity
    • striated flow regimes – especially at $30^\circ$ to $60^\circ$
    • difficult in all liquid systems (rate)
    • difficult in all gas systems (striation)
Cuttings Beds

• Symmetric suspension - constant concentration in cross section
• Asymmetric suspension - all carried, but more at bottom
• Moving bed - like a dune
• Stationary bed - builds to height dictated by flow rate
• Boycott settling - explains severe solids drop out in the 30 to 60 degree range.
Boycott Settling

Gas Rise Rate???
Vertical holes - 1000 ft/hr
30 to 60° deviation - 4000 to 7000 ft/hr

Region of greatest settling
Problems, 30 to 60 degrees – the Boycott Region

Lighter fluids rise to the top side of the wellbore (striatation) and dense fluids and cuttings drop out to the bottom out of the fast moving upper fluids – result is poor hole cleaning and sticking of strings.
Consequences of Poor Hole Cleaning

• Bridging - sticking pipe
• Failure to run to bottom
• Debris in perfs
• Emulsions and scale “seeds” left in the well?
• Cave-ins? - probably not
Where are the casing set points in this example?
BUT, is it stable as the hole approaches horizontal? Remember that hole stability is lowest in the bend area.
Drilling Fluid Operating “Window”

- Mud density must be higher than the pore pressure to keep fluids from entering the well.
- Mud density must control tendency of shale to spall particles into wellbore
- Mud density must be less than the formation fracture (extension) gradient – corrected for friction pressures while circulating. The pressure exerted by the fluid at any depth is a function of its density plus the friction pressure in the circulating path back to the surface.
Drilling Wellbore Stability

• Issues - during drilling, completion and production
• Destabilizing Mechanism
  – support pressure too low (spalling)
  – support pressure too high (fracturing)
  – Rx with drilling fluids (sloughing, swelling)
  – formation stress unloading
A graph showing the relationship between well angle and mud density. The graph indicates that there are two critical points: one labeled "fracturing" and another labeled "safe." Between these two points, there is a zone labeled "pore pressure uncontrolled, shale heaving." The x-axis is labeled "Mud Density," and the y-axis is labeled "Well angle."
??? - Can't drill a horizontal here!

- fracturing
- pore pressure uncontrolled, shale heaving...
- safe

Well angle

Mud Density
A model of wellbore stability (most stressed regions in blue) of a horizontal wellbore.
Broad Based Conclusion

• Most Important Failure Factors
  – pore pressure prediction
  – weak, fissible beddling planes
  – low support pressures
  – time dependent loss of strength

• Open holes best in stable formations (carbonates, clastics)

• Most instability problems in the shales
So, how far do you drill?

- Consider edge boundaries
- Consider drilling costs (usually low in lateral)
- Consider vertical perm
Effect of length and horizontal permeability on PI in horizontal wells

Drilled length x Kh

P.I. (Mscfd/psi)

Hariot-Watt Horizontal Study
Effect of horizontal well factors on PI

Hariot-Watt Horizontal Study
How long a well can you effectively complete and produce? Depends on shape, angle, path and fluids.
Improving Artificial Lift for Horizontal Wells by Using Rat Hole on Short Radius

Liquid level

Lift system set low
Production Index Factors

(a comparison to horizontal well performance)

• Theoretical PIF’s may range from 1 to 8.
• Actual PIF’s range from 1 to about 4 or 5.
• Causes:
  – reservoir not homogeneous
  – reservoir “estimates” too generous
  – completion design was an after-thought
### Horizontal Well PIF’s

(1300 well study)

<table>
<thead>
<tr>
<th>Reservoir Type</th>
<th>PIF Average (Mean)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Reservoirs</td>
<td>4</td>
</tr>
<tr>
<td>Heavy Oil Reservoirs</td>
<td>7</td>
</tr>
<tr>
<td>Fractured Reservoirs</td>
<td>12</td>
</tr>
<tr>
<td>All reservoirs comb.</td>
<td>5</td>
</tr>
</tbody>
</table>

**PIF = Prod. Improvement Factor:** comparison of horizontal to vertical prod of wells at the same location.
Lower Than Expected Production?

• 1. Low vertical perm.
• 2. Formation damage
• 3. Reservoir quality variance
• 4. Pressure drop along the lateral ?? - few psi at max, but can be important.
• 5. Poor initial knowledge and assumptions.
Effect of Kh/Kv

PIF

Horiz Length, ft

PEI, Nov 97

kh/kv=1
kh/kv=5
kh/kv=10
kh/kv=25
kh/kv=50
Horiz vs Frac

Xf equivalent

horizontal length, ft

kh/kv=1
kh/kv=5
kh/kv=10
kh/kv=25
kh/kv=50

PEI, Nov 97

3/14/2009

George E. King Engineering
GEKEngineering.com
Horizontal Uses?

• Consider them any time a well is designed.

• Particularly good for:
  – Coning control,
  – Extending reach,
  – Increasing reservoir contact,
  – Lowering drawdown per unit area,
  – As a platform for multiple fracture stimulation
  – In some water injector projects.