Horizontal Well Stimulation Optimization

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Selecting Horizontal vs Vertical Wells

• Can vertical wells be stimulated effectively?
• Can vertical wells drain the reservoir (contact the required volume)?
• Can vertical infill wells be drilled economically?
• Can field development economics be improved by switching to horizontals?
Selection of Horizontal Well Completion/Stimulation Method

• Know the reservoir
  – Deliverability (kv, kh, Pi, GLR)
  – Stress field magnitude and orientation
  – Drainage area shape and size

• Define the well
  – Maximum possible length
  – Limitations on orientation
  – Expected skin damage
  – Options for completion
    • Cased/cemented; open-hole; uncemented liner
Selection of Stimulation Method

- No stimulation or cleanup
- Acid or mud-cleanup Wash
- Longitudinal acid frac
- Transverse acid fracs (multiples)
- Longitudinal propped frac
  - Longitudinal frac with “hair” on it
- Transverse propped fracs (multiples)
Factors Affecting Horizontal versus Vertical Well Performance

- Flow path in proppant pack
- Near-well tortuosity and flow restrictions
- Reservoir drainage area
- Interference of multiple transverse fractures
- Drainage aspect ratio
Maximum Attainable Effective Xf Depends on:

- Reservoir permeability
- Frac fluid cleanup
- Producing water-cut and condensate yield
- Applied drawdown
- Created fracture length
- Average proppant concentration
- Applied closure stress
- Reservoir rock “hardness”

Effective frac length is usually much shorter than expected
Growth of Fractures in a Layered Medium

- Overburden Stress, S_max
- Frac Ports: 1" x 3"
- Wellbore diam: 8"
- Sh_max
- Sh_min
- 80 feet
- 2000 feet
Assumed Fracture Geometry for Productivity Estimates: Vertical Well

Gross Fracture Height Open to Flow

Constant Conductivity with Length and Height
Assumed Fracture Geometry for Productivity Estimates: Horizontal Transverse

Gross Fracture Height Open to Flow

Constant Conductivity with Length and Height
Multiple Transverse Fractures

- Thick reservoirs
- Long Xf possible
  - Low perm
  - Efficient stimulations
- Compartmentalized reservoirs
- Linear reservoir flow “channels”
- Difficult and expensive to place in desired locations
Assumed Fracture Geometry for Productivity Estimates: Horizontal Longitudinal

Gross Fracture Height Open to Flow

Constant Conductivity with Length and Height
Longitudinal Fractures

- Thin reservoir sections
- Low kv/kh in thick reservoirs
- Better when effective Xf is low
- Better in continuous reservoirs
- Large volume treatments
- Easy to place and pump effectively
Complex Longitudinal with “Hair”

- Generated in near-isotropic stress states
- Usually results from intended longitudinal fracs
- More of an accident or “gift” than an intentional result
Direction of Fracture Growth

• Controlled by in-situ stress field
  – Magnitude of all three principal stresses
  – Principal stress axis
  – Degree of overpressure or depletion
• Direction of well (azimuth)
• Deviation of well from vertical
Radial Coordinate System of Stresses around a Wellbore

\[ \sigma_r \quad \sigma_t \quad \sigma_v \]

\[ \sigma_x \quad \sigma_y \quad \sigma_v \]
Stresses Vary with Direction and Distance from Well

\[ \sigma_r = \frac{\sigma_h + \sigma_H}{2} \left( 1 - \frac{r_w^2}{r^2} \right) + \frac{\sigma_h - \sigma_H}{2} \left( 1 - 4 \frac{r_w^2}{r^2} + 3 \frac{r_w^4}{r^4} \right) \cos 2\theta + \frac{r_w^2}{r^2} \left( P_w - \alpha P_o \right) \]

\[ \sigma_t = \frac{\sigma_h + \sigma_H}{2} \left( 1 + \frac{r_w^2}{r^2} \right) - \frac{\sigma_h - \sigma_H}{2} \left( 1 + 3 \frac{r_w^4}{r^4} \right) \cos 2\theta - \frac{r_w^2}{r^2} \left( P_w - \alpha P_o \right) \]

\[ \sigma_v = P_{ob} - \alpha P_o \]

- \( P_o \) = far field pore pressure
- \( P_w \) = wellbore fluid pressure
- \( P_{ob} \) = overburden pressure
- \( r \) = distance from wellbore
- \( \sigma_H \) = maximum horizontal stress
- \( \sigma_h \) = minimum horizontal stress
- \( \theta \) = angle from direction of minimum stress
Tangential Stress Distribution
Around a Horizontal Well

The wellbore acts as a tunnel arch: Vertical stress is transmitted to the sides of the hole.

Parameters:
- $S_1 = 6000$
- $S_2 = 6000$
- $S_3 = 4200$
- $\text{IncS}_1 = 0$
- $\text{AzSH} = 70$
- $\text{Azi} = 70$
- $\text{Dev} = 90$
Fracture Initiation at Point of Minimum Tangential Stress

\[ \sigma_h \text{ max} + \text{well pressure} = \sigma_h \text{ min} \]

Failure when tangential stress reaches zero
Borehole Stability: Near-Well Stress State

- Vertical far-field Stress
- Max Horizontal far-field Stress
- Min Horizontal far-field Stress
- Axial Stress
- Radial Stress
- Tangential Near-Well Stress
High Treating Pressures in Deviated Wells

![Graph showing the relationship between Borehole Deviation Angle and Breakdown Gradient](image)

- Breakdown Gradient, psi/ft
- Borehole Deviation Angle, degrees
- a = 90
- a = 45
- a = 0
Preferred Fracture Direction for a Normal Fault Environment

**ORIENTATION OF FRACTURES**

**TENDENCY FOR FRACTURES**

Principal stresses:
- $S1 = 8845$
- $S2 = 7588$
- $S3 = 7099$

$p=4830$, $DeltaP=0$, $Biot=1$, $PoisRat=0.36$
Preferred Frac Direction for a Thrust- or Strike-Slip Fault Environment

Principal stresses:
- $S1 = 8000$
- $S2 = 6000$
- $S3 = 4200$

$p_p=2385$, $\Delta p=0$, $Biot=1$, $PoisRat=0.18$

$T0=100$
Predicting Production from Multiple Transverse Fractures

• Determine reservoir performance from vertical wells
  – Reservoir flow capacity (kh)
  – Effective Half Length (xf)
  – Original Gas in Place (OGIP) contacted by vertical

• Generate a metric to evaluate completion efficiency of multiply fractured wells

• Determine the number of fractures to place in a lateral for effective reservoir drainage
Horizontal Well Production Characterized by Vertical Well Performance

- Vertical well performance is needed to determine reservoir properties:
  - $KH$, $P^*$, $X_f$, $A$, $L/W$
- Vertical transverse fracs on the lateral are assumed to clean-up and perform like the vertical-well frac
- The reservoir is assumed to be isotropic and homogeneous along the lateral
Horizontal Wells: Composite Transverse Fracs
Model Setup – 2 Cases

• Single Phase Gas simulator with separate fractures contributing to flow against a constant surface pressure
• Analyze total well response as a single zone to determine composite properties
• Case 1 – Variable kh in each fracture
• Case 2 – Variable Xf in each fracture
Case 1 – Variable Flow Capacity $kh$

<table>
<thead>
<tr>
<th>Fracture</th>
<th>Height (ft)</th>
<th>Permeability (md)</th>
<th>$kh$ (md-ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture 1</td>
<td>20</td>
<td>0.05</td>
<td>1.0</td>
</tr>
<tr>
<td>Fracture 2</td>
<td>5</td>
<td>0.1</td>
<td>0.5</td>
</tr>
<tr>
<td>Fracture 3</td>
<td>50</td>
<td>0.001</td>
<td>0.05</td>
</tr>
<tr>
<td>Fracture 4</td>
<td>25</td>
<td>0.025</td>
<td>0.625</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>2.175</strong></td>
</tr>
</tbody>
</table>
Case 1 – Type Curve Match
Case 1 – Semilog Plot

Semilog Plot $k = 0.0218$ md and $X_f = 116.6$ feet - Case 1

$\frac{\Delta M(P)}{Q}$ against $T_a$ (days)
Case 1 – Single Zone Composite Analysis

- \( X_f = 117 \text{ ft} \) (actual 150 ft)
- \( \text{OGIP} = 6.61 \text{ BCF} \) (actual 13.2 BCF)
  - Half the net pay does not contribute to production
- \( k_h = 2.18 \text{ mdft} \) (actual \( k_h = 2.18 \text{ mdft} \))
- Flow capacity from multiple fractures is accurately measured by a single composite analysis

\[
k_h = \frac{\sum k_i h_i}{\sum h_i}
\]
Case 2 – Variable Half Length Xf

<table>
<thead>
<tr>
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<th>Height (ft)</th>
<th>Permeability (md)</th>
<th>Xf (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture 1</td>
<td>20</td>
<td>0.05</td>
<td>50</td>
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<tr>
<td>Fracture 2</td>
<td>5</td>
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<td>Fracture 3</td>
<td>50</td>
<td>0.05</td>
<td>500</td>
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<tr>
<td>Fracture 4</td>
<td>25</td>
<td>0.05</td>
<td>300</td>
</tr>
</tbody>
</table>
Case 2 – Type Curve Match
Case 2 – Semilog Plot

Semilog Plot $k = 0.0500 \text{ md and } X_f = 345.3 \text{ feet} - \text{Case 2}$
Case 2 – Single Zone Composite Analysis

- \( kh = 5 \text{ md.ft} \) (actual 5 md.ft)
- \( \text{OGIP} = 13.23 \text{ BCF} \) (actual 13.23)

\[
X_f = \frac{\sum h_i X_f}{\sum h_i}
\]

- \( X_f = 342 \text{ ft} \) (semilog plot shows 345 ft)
- For a system with little permeability variation the \( X_f \) will be the height averaged individual \( X_f \) of each of the fractures. As the variance in permeability increases the measured \( X_f \) decreases
Fracture Efficiency

• As more fractures are added to a lateral the total well kh should increase
• Assuming a constant kh for each fracture

• Average kh should be measured from a single vertical fracture

\[
\text{Fracture Efficiency} = \frac{(kh)_{\text{Horizontal}}}{n \ (kh)_{\text{Average}}}
\]
Production Rate Decline for Internal and External Fractures

10 Stage vs 20 Stage Treatments in a 5000 ft Lateral

- 10 stage Bounding Frac
- 10 Stage Inner Frac
- 10 Stage Total Rate
- 20 Stage Bounding Frac
- 20 Stage Inner Frac
- 20 Stage Total Rate

Production Rate (mmscf/day)

Time (days)
Fracture Spacing Equation

- Based on the radius of investigation formula the time to interfere for a given spacing can be calculated

\[
\text{Fracture Spacing (ft)} = 0.3135 \sqrt{\frac{kt}{\phi \mu c_t}}
\]

- time, \( t \) in days
- permeability, \( k \) in millidarcy
- porosity, \( \phi \)
- viscosity, \( \mu \) in cp
- total compressibility, \( c_t \) in 1/psi
Fracture Spacing when Interference will Occur

Fracture Spacing (ft)

Permeability (md)

- 6 Months
- 1 Year
- 1 Month
**Field Example – Vertical Well**

**Vertical Well**

- Gas in Place = 1.77 BCF - Equivalent Area 27.22 acres - L/W ratio 2.72 - Vertical Well
- Volumetric OGIP = 1.82 BCF

- **k = 0.0303 md and Xf = 101.9 feet**

- **Boundary**

- **Rate (MSCF/day)**

- **Pressure (psia)**
Field Example – Vertical Well

• Vertical Well Production Analysis
  – $kh = 2.4 \text{ md.ft}$
  – Infinite conductivity half length 102 ft
  – Gas in place 1.77 BCF
Field Example – Horizontal Well

Horizontal Well

- Gas in Place = 2.90 BCF - Equivalent Area 44.49 acres - L/W ratio 2.47
- Volumetric OGIP = 2.93 BCF

- $k = 0.0802$ md and $X_f = 134.7$ feet

- $T_{DA}$
- $P_{wD}$
- $\Delta M(P)/Q$ vs $T_a$ (days)
- Rate (MSCF/day) vs Time (Days)
- Pressure (psia) vs Time (Days)
Field Example - Summary

• Horizontal Well
  – 12 fractures in a 4000 ft lateral
  – 363 ft actual spacing
  – Kh 6.32 md.ft
  – Infinite conductivity Half Length 135 ft
  – Gas in place 2.90 BCF

• Fracture Efficiency = 6.32 / 12*2.4
  – 22% (3 out of 12 fractures contributing)

• Fracture Spacing
  – Based on 6 month interference time a fracture spacing of 1360 ft is more appropriate (3 fractures)
  – The fractures interfere after 12.6 days at a spacing of 363 ft
Summary

• Flow capacity (kh) from production analysis of multiple fractures is accurate
• Xf from production analysis is a poor method to evaluate completion efficiency
• For an efficient completion kh from each layer should add (total \( \text{kh} = \text{number fracs} \times \text{average single layer } \text{kh} \))
• Increasing lateral length and distance between the bounding fractures will increase contacted reserves
• Placing more fractures in a lateral than the permeability can support leads to destructive interference
Effect of Producing Lateral Length on Production Rate
Effect of Stimulation (Rwa) on Production Rate
Comparing Transverse and Longitudinal Fracs

• If KH is additive for each transverse frac
  – Does the number of producing fracs times effective length exceed drilled lateral length?
  – Is the production dominated by secondary joints and fractures?
  – Can a longitudinal frac expose more area?
Comparison of Predicted Transverse and Longitudinal Frac Performance in Low Perm System
Recommendations for Horizontal Well Completions

- Maximize productive well length
- Establish communication with the reservoir across entire well length
- Extensive stimulation outside the well (frac-length) is not critical
- Propagation of secondary fractures (off longitudinal) may be beneficial (not clear from production response)
Cemented vs. Uncemented Liners and Open-hole Completions

• Cemented liners and/or casing
  – Only for matrix-flow systems
  – Only when borehole stability is questionable
  – When zonal isolation for stimulation is absolutely necessary

• Uncemented liners (with limited perfs)
  – Longitudinal fracs (acid and propped)
  – Re-entering or re-activating existing fractures

• Open-hole completions
  – Only in hard, competent rock
  – Good for surface acid-wash completions
  – Acid and water-fracs for opening existing natural fractures
    • Poor control of fluid entry
    • Difficult to ensure multiple fractures treated
Fracturing with Cemented Liners

Long flow path in fracture requires high conductivity and long effective Xf, with similar behavior to vertical well.

Narrow Fracture Width Causes High Pressure Gradients

No production allowed through cemented section.
Stress Shadowing and Frac Re-Orientation

Max Stress

First frac: Transverse

Second frac: May be Axial

Induced deformation (strain) generates stress in proportion to YME

Third frac: May be oriented arbitrarily

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Typical Observation of Multiple Fracs in Horizontal Wells
Interaction of Fractures: Simultaneous Injection into 11 Fractures
Injection into 7 Sequentially Propagated Fractures
Achieving Diversion and Fracturing the Entire Lateral

• Cemented liner with limited-entry perforating
  – Limit number and size of perforations
• Multiple plug and perf stages
• Open-hole with liner and external packers
  – Chemical “swell” packers (Halliburton)
  – Hydraulic-set packers
  – Inflatable OH packers
• Sliding sleeve and frac-ports for individual stages
• Dynamic diversion with uncemented liners
Packers Plus Mechanical Isolation System for Open-Hole Stacked-Fracs

Sliding-Sleeve Frac Ports

Open-Hole hydraulic-Set Packers
Wellbore Tangential Stress Exerted by Packer Setting Pressure

Net Stress at Borehole Wall, psi

Angle Around Wellbore, Degrees from Side

-10000
-5000
0
5000
10000
15000
20000

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Diversion in Uncemented-Liner Fracs

- Limited-entry perfs (pre-drilled or shot in-place)
  - Few holes
  - Large perf spacing
- Perf Balls
  - Only plug perfs
  - No diversion in annulus
- Large sand (gravel) in annulus and perfs
  - Bridges in frac opening
  - Diverts in annulus
- Dynamic pressure gradient in annulus
- Combination of balls and gravel is recommended
## Estimation of Annular Friction

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</thead>
<tbody>
<tr>
<td>Liner OD=</td>
<td>7</td>
<td>4.5</td>
<td>3.5</td>
<td>5.5</td>
<td>2.675</td>
<td>0</td>
<td>0</td>
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<tr>
<td>HydDiam(in)=</td>
<td>2.8024911</td>
<td>2.5953589</td>
<td>4.16066282</td>
<td>5.16592303</td>
<td>5.42724348</td>
<td>6.125</td>
<td>3.992</td>
</tr>
</tbody>
</table>
Annular Friction Pressure Results

![Graph showing results of Annular Friction Pressure]
Benefits of Uncemented Liners

Fluid flow in annulus is always toward fluid exit (open fracture). High dP in annulus allows diversion of fluid from different perfs. Screenout of first-open fracs builds flow resistance. Later slurry diverted to new fractures. Short effective flow path and low conductivity needed.
Treating Pressure for 4000’ Lateral Frac with Balls with Dynamic Diversion

Graph showing:
- Treating Pressure (psi) (A)
- Calc’d Bottomhole Pr (psi) (A)
- Slurry Rate (bpm) (B)
- Slurry Proppant Conc (lb/gal) (B)
- Bottomhole Proppant Conc (lb/gal) (C)

Graph timeline:
- 09:00 to 12:00 on 10/20/2005

Graph axes:
- Y-axis: 0 to 10000 psi
- X-axis: Time from 09:00 to 12:00

Legend:
- Red: Treating Pressure (psi)
- Blue: Calc’d Bottomhole Pr (psi)
- Green: Slurry Rate (bpm)
- Pink: Slurry Proppant Conc (lb/gal)
- Purple: Bottomhole Proppant Conc (lb/gal)
Summary and Conclusions

• The selection of a stimulation/completion design cannot be made without an accurate reservoir description

• Reservoir geometry and drainage pattern may control well performance

• Reservoir response to stimulation in vertical wells should be understood

• In almost all cases, maximizing productive lateral length is the primary goal
General Guidelines

• If the reservoir has high matrix kh
  – Attempt minimal drilling damage or surface wash
  – Well azimuth is not critical

• With pre-existing natural fractures (open or mineralized)
  – Drill across fractures and attempt to re-open
  – Acid-frac or prop-frac through uncemented liner

• Low matrix kh or low kv/kh
  – Must design for propped frac
  – Longitudinal fracs where vertical well Xf is poor
  – Transverse fracs only when Xf>250 ft is possible
Shear Domain Stimulation

- Different ideas about when and where it can work
  - Nearly isotropic horizontal stresses
    - Open and extend fractures in all directions
    - Pumped at high frac rate to maintain injection above leakoff rate
  - High horizontal stress anisotropy
    - Elevate pore pressure and relieve net stress causing massive shear failure over large area
    - Requires injection “below frac pressure” and access to large reservoir volume for pore pressure change

- Simul-frac designs
  - Enhance shear stimulated volume by pumping into parallel wells simultaneously