Considerations for Infill Well Development in Low Permeability Reservoirs

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Technical Manager – Unconventional Completions

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Topics

• Continuous Improvement in Field Development
• What Drives Frac / Well Spacing?
• Field Development Workflow
  • Bakken Shale Example
  • Cana Woodford Shale Example
The Quest For The Optimized Completion

Cana-Woodford Completions Enhanced

Old Design:
- 10 Frac Stages
- 40 Perf Clusters
- Sand: 3.5 MM lbs.
- Fluid: 130k Bbls.

New Design:
- 20 Frac Stages
- 80 Perf Clusters
- Sand: 6.0 MM lbs.
- Fluid: 140k Bbls.

NYSE: DVN
www.devonenergy.com
Slide 21
The Quest For The Optimized Completion

Maximizing Recovery Efficiency
Improving Frac Design

Sliding Sleeve Completion

<table>
<thead>
<tr>
<th>Annulus</th>
<th>Stages</th>
<th>Frac Ports per Stage</th>
<th>Potential Entry Points</th>
</tr>
</thead>
<tbody>
<tr>
<td>Free fluid between packers</td>
<td>30</td>
<td>1</td>
<td>30</td>
</tr>
</tbody>
</table>

Cemented Liner Completion

<table>
<thead>
<tr>
<th>Annulus</th>
<th>Stages</th>
<th>Perforation Clusters per Stage</th>
<th>Potential Entry Points</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cemented</td>
<td>40</td>
<td>3</td>
<td>120</td>
</tr>
</tbody>
</table>

New Completion Design Delivers Superior Results
50% to 75% Increases in 30, 60, 90 Day Rates

% Increase Cemented Liners vs. Sliding Sleeves

- 30-Day Average: +75.0%, +66.0%, +58.0%
- 60-Day Average: +70.0%
- 90-Day Average: +57.0%, +52.0%, +61.0%

Whiting Petroleum Corporation

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The Quest For The Optimized Completion

**Eagle Ford**
Completion design enhancements driving improved well performance

- Improvements in stimulation design outpacing impacts from downspacing
  - 2013 wells at 40 & 60 acre spacing exhibit higher IP than 2011 wells at 80 - 160 acre spacing
  - Early 2014 wells at 40 acre spacing exhibiting further improvements

- Ongoing testing of stimulation design to continually improve well performance
  - Zipper stimulations from pads materially impacting complexity & improving recovery
  - Fluids, volumes, rates, cluster spacing and proppant loading evolving with spacing
  - Geologic completions, proppant size, gel loading, sleeve technology, perforation clusters being tested

MRO-operated wells, gross basis
2013 includes wells with 180d of production excluding lease retention wells and ≥400 ft stage spacing wells
*2014 wells to date (15) using updated completion design
The Quest For Optimized Field Development
The Quest For Optimized Field Development

Well Density Schematic

6 / 7 Well Density*
No Lower Three Forks
Stand-Alone Locations

8 Well Density*
Lower Three Forks
Productive

TF 2 &3 Upside**
TF3 & Additional
TF Wells

* Assumes 15% recovery factor.
** "Super unit" equivalent to lease line drilling.
The Quest For Optimized Field Development

Williston Basin Development Drilling Plan

- Missouri Breaks
- Cassandra
- Sanish
- Hidden Bench
- Pronghorn
- Tarpon

- Current Drilling Pattern
- Potential High Density Infills
- New Objectives
- Lease Line & Cross-Unit

Energy + Technology = Growth

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The Quest For Optimized Field Development

Continued Robust Hawkinson Performance

- Continued strong production after 150+ days

- 13 of 14 wells trending on average 50% above 603 MBoe model EUR
  - Completed using standard design with ~100,000 pounds of proppant per stage (30 total stages)

- To date the original existing 3 wells continue to produce on average at or better than prior to drilling and completing the additional 11 wells

- Validates full-field development & demonstrates vast resource potential

Hawkinson Unit

1,320’ Pilot

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North American Horizontal Evolution

### Average Lateral Length (ft)

<table>
<thead>
<tr>
<th>Region</th>
<th>2013</th>
<th>2008</th>
<th>Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horn River</td>
<td>4516</td>
<td>5479</td>
<td>86%</td>
</tr>
<tr>
<td>Montney</td>
<td>3536</td>
<td>5479</td>
<td>55%</td>
</tr>
<tr>
<td>Bakken</td>
<td>4882</td>
<td>6908</td>
<td>31%</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>2485</td>
<td>5712</td>
<td>130%</td>
</tr>
<tr>
<td>Barnett</td>
<td>3556</td>
<td>4982</td>
<td>37%</td>
</tr>
<tr>
<td>Fayetteville</td>
<td>4064</td>
<td>5384</td>
<td>33%</td>
</tr>
<tr>
<td>Marcellus</td>
<td>2910</td>
<td>5290</td>
<td>82%</td>
</tr>
<tr>
<td>Haynesville</td>
<td>4204</td>
<td>5677</td>
<td>35%</td>
</tr>
</tbody>
</table>

### Average Frac Stage Count

<table>
<thead>
<tr>
<th>Region</th>
<th>2013</th>
<th>2008</th>
<th>Stage Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horn River</td>
<td>11</td>
<td>22</td>
<td>381 ft</td>
</tr>
<tr>
<td>Montney</td>
<td>17</td>
<td>22</td>
<td>411 ft</td>
</tr>
<tr>
<td>Bakken</td>
<td>14</td>
<td>32</td>
<td>322 ft</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>10</td>
<td>23</td>
<td>589 ft</td>
</tr>
<tr>
<td>Barnett</td>
<td>10</td>
<td>24</td>
<td>283 ft</td>
</tr>
<tr>
<td>Fayetteville</td>
<td>5</td>
<td>11</td>
<td>493 ft</td>
</tr>
<tr>
<td>Marcellus</td>
<td>8</td>
<td>22</td>
<td>248 ft</td>
</tr>
<tr>
<td>Haynesville</td>
<td>10</td>
<td>15</td>
<td>364 ft</td>
</tr>
</tbody>
</table>

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US Unconventional Production

Unconventional Liquid Plays
(best 3 months production bpd)

Bakken

Best 3-month average ~ 340 bbl/d

Haynesville

Best 3-month avg ~ 7,650 Mcf/d

Unconventional Gas Plays
(best 3 months production mcf/d)

Eagle Ford

Best 3-month average ~ 518 bbl/d

Fayetteville

Best 3-month avg ~ 1,900 Mcf/d
Topics

- Continuous Improvement in Field Development
- What Drives Frac / Well Spacing?
- Field Development Workflow
  - Bakken Shale Example
  - Cana Woodford Shale Example
Cleveland Sand Horizontal Well Development

- Vertical well development since 1980s
- Produces both oil and gas
- Revitalized with horizontal wells in 2000s
- Completion Techniques:
  - One large frac with ball diversion
  - Packers / Port Collars

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Cleveland Sand Frac Spacing Optimization: 2005

Horizontal Well Productivity Improvement Versus Increase in Well Cost

- An economic optimum of 300 ft hydraulic fracture spacing
- 100 ft spacing
- 250 ft spacing
- 500 ft spacing: Standard completion at the time

Schlumberger Internal Study: October, 2005

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BP Results After Increasing Frac Stages: 2011

Graph showing cumulative production over time for different fracture stage lengths and spacings.

- **4000 ft lateral, 9 fracs**
  - 444 ft spacing
  - 11% Cum difference

- **2500 ft lateral, 9 fracs**
  - 277 ft spacing
  - 47% Cum difference

- **2500 ft lateral, 5 fracs**
  - 500 ft spacing

Additional data:
- **h= 45ft**
- **Φ= 9%**
- **Pi= 1825 psia**
- **k= .008 mD**
- **A= 320 Acres**
- **x= 330ft**
- **Fcd= 2.8**

Note: 4000' = 1212' heel to toe
2500' = 2500' heel to toe
Cleveland Sand Fracture Spacing Optimization

xf = 250 ft, h = 20 ft and 4 fracs

Fracture Spacing Limited
Fracture Conductivity Limited

Schlumberger Internal Study: October, 2005

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Parameters That Control Well / Frac Spacing

- **Matrix Perm**
  - Frac spacing and conductivity needs

- **Natural Fractures**
  - Enhanced permeability, stimulation difficulty, stimulated geometry

- **Faults**
  - Inefficient fracturing and unwanted fluid migration potential

- **Reservoir Fluids**
  - Fluid viscosity impacts pressure transient

- **Variability Along the Horizontal Well**
  - Quality of the reservoir will vary along the well
  - Well may not stay within the reservoir

- **Orientation of Well Relative to Stress Field**
  - Frac orientation and spacing
Topics

- Continuous Improvement in Field Development
- What Drives Frac / Well Spacing?
- Field Development Workflow
  - Bakken Shale Example
  - Cana Woodford Shale Example
Bakken Shale Field Development Challenges:
- Hydraulic fracture spacing
- Offset well placement
- Bakken / Three Forks development
- Well placement between Bakken and Three Forks

Daily Oil Production: Permian Basin, Eagle Ford and Bakken
January 2007 to August 2014 (est.)

Source: Energy Information Administration

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Fracturing pressure responses indicate that the number of fractures varies from one to three, with one dominant frac most common (Uncemented Port Collar / Perforated Completions)
Single Well Optimization: Frac Geometries

Height growth and vertical communication between Bakken and Three Forks

Large frac geometry infers fewer fractures

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SPE142388, SPE 163855
History match early production

Reconcile number of fractures (producing area) and fracture conductivity

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SPE152177
Calibrated Model used to Forecast Recovery

Forecast EUR

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Calibrated Model Optimize Completions

Low perm: 0.0001 – 0.005 md
High perm: \(k > 0.005\) md

Economic sensitivity analyses to optimize the number of frac stages

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Expanding to Field Development: Well Spacing

3-Well Model      5-Well Model      6-Well Model      7-Well Model

Unconventional Resources  SPE 152177  Schlumberger
Sustained Vertical Communication?

Alternating Bakken and Three Forks Laterals

M. Bakken
TF1

Large Fracs

M. Bakken
TF1

Small Fracs

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SPE 152177
The Impact of Production

Pore pressure distribution after 600 days of production

Closure stress reduction is directly proportional to drop in pore pressure.

Pore pressure reduction is inversely proportional to mechanical properties anisotropy in TIV rocks.

Closure stress does not fall as fast in TIV rocks as isotropic rocks.
Evolution of Frac Geometry with Time / Depletion

Frac geometry pre Bakken depletion from offset well

Frac length and height growth can vary with pore pressure depletion

Can the Bakken and Three Forks be produced together?

Frac geometry post Bakken depletion from offset well

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SPE142388
Asymmetric Fracture Geometry due to Depletion

Fracture geometry for initial conditions

Fracture geometry for infill wells

Planar3D
Fully 3D asymmetric hydraulic fracturing simulator
What is the Impact on Infill Well Production?

Pressure Profile for parent well evolves with time / depletion

Optimum infill well distance from the parent well will vary with time
Development Challenges due to Depletion

Stimulation away from parent well can be adversely affected.
Will alter infill development strategy
Field Development Strategy due to Depletion

Instead of having this…
Field Development Strategy due to Depletion

We have this...

Best addressed with a calibrated reservoir model
Woodford horizontal stress anisotropy is ~ 1,500 psi from multiple 1D MEMs

Result is Planar Fractures
Large Slickwater Fracs = Long Frac Lengths

Hydraulic lengths intersect offset wells

Conductive lengths are much shorter than hydraulic lengths
Long Frac Lengths are Modeled
Long Frac Lengths are Measured

Frac pressure communication with offset wells

1 2 3 4 5 6 7

2,950 ft

3,990 ft
Woodford Pore Pressure Depletion
Woodford Shale Frac Assymetry

Time = 288.8 min
Max velocity = 0.40 ft/s

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URTeC 1923397
Woodford Producing Intervals
Woodford Shale Productive Intervals

Only Woodford C – E appear to be producing.
Modeled Production Validates Productive Intervals
Woodford Shale Field Development Challenge

Unrecovered hydrocarbons

WFD A
WFD B
WFD C
WFD D
WFD E
WFD F
WFD G

Unrecovered hydrocarbons

Unconventional Resources

URTeC 1923397
Infill well development adversely impacts parent wells.
Operational Solutions to Address Challenges

Develop fracture designs to address loss of vertical fracture conductivity

Evaluate reverse hybrid technique:
  – Improve effective frac height and infill well proppant transport
  – Reduced overall fluid volume for better infill well stimulation results
  – Improved propped to unpropped fracture ratio

Change perf design to improve injectivity into all perfs
  – Reduced frac lengths by injecting into more clusters

Provide flow back energy to flooded existing producers:
  – Re-frac the existing producing well with an energized fluid, distributed along the entire lateral in the fracture system with degradable diverters
  – Energized fluids in the new well stimulations

Reservoir depletion management
  – Temporal optimization of infill development
Summary

• Field development is controlled by reservoir and completion parameters:
  – Reservoir Parameters
    Perm, natural fractures, geomechanical setting…
  – Completion Parameters
    Perf spacing, stage design, frac fluid type and volume, production management…

• Infill well placement is a function of:
  – Perm, pressure, and stimulated / drainage volume
  – Time of infill well relative to parent well(s)
  – Durability of fracture conductivity, especially vertically

• Parent wells will be impacted:
  – Likely to be adverse on wells with large production volumes
  – Options to protect parent wells:
    - Shut in parent wells
    - Aggressive drawdown of parent wells during infill well fracturing
    - Pressure up parent well with (energized) fluids
    - Refrac parent wells utilizing diversion technologies
    - Use energies fluids on infill wells