A Workflow to Assess Multi-Staged Horizontal Well Plays

SPE Back to Basics Seminar
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What metrics are you using to assess your horizontal wells?

- Initial production rate at a certain time in days?
  - IP30, IP60 …
- Cumulative production at a certain time?
  - Cum 1 yr, Cum 2yr …
- Other
Introduction

• Multi-Stage Horizontal Fracture Challenges
  1. Developing Type Curves
  2. Effectiveness of Current Fracture Stimulation Strategy
     1. Identifying successful plays
     2. Identifying successful companies
     3. What makes a good well?
        • Sweet spot
        • Stimulation
  4. Optimal treatment selection
Approach

• Illustrated by case studies
  – Viking Plato
  – Montney Gas
  • 2 case studies
Important Concept - Flow Regimes

• What are they?
  – Early (transient)
    • Drainage area increasing
  – Late (bounded)
    • Drainage area fixed

• Vertical and horizontal wells
  – What are the important flow regimes
    • Radial flow (transient)
    • Linear flow (transient)
    • Bounded flow
  – They have a mathematical signature
Modified Fetkovich Plot or Blasingame Type Curve

Overcomes problem of shut-ins

Caution:
Big rate changes will give false unit slopes
Can be handled by appropriate filtering

If $p_{wf}$ changes with time replace with
$q/(p_i - p_{wf}) = q/\Delta p$
Case 1 - SPE 162813
Viking - Oil

• Widespread across Alberta and Saskatchewan
  – 5 fields focused on

• Cretaceous age

• Deposited in transitional to marine environment
  – Direction of shoreline was NW/SE

• thinly-laminated, bioturbated, clastic
  (sand/silt/shale)
Production History

• Production began:
  – Redwater + Greater Dodsland in 1950’s
  – Provost in early 1960’s
  – Plato in late 1960’s
  – Halkirk in early 1980’s

• Wells predominantly vertical
  – Hydraulically fractured (sometimes repeatedly)
  – Starting in 2006 horizontal multi-stage fracturing started
    • 1100 such wells

• Some attempts at waterflooding
  – Mostly unsuccessful
Reservoir Properties

- Pi ≈ 6.2 MPa
- Reservoir Temperature 28 – 30 °C
- Depth ≈ 700 m
- Low GOR ? (reporting issue in Saskatchewan)
- Soft friable rocks
  - Difficulties fracturing through even thin ‘barriers’
- Swelling clays
- Paraffin based waxy light crude (37 to 39 API)
  - Cloud point ≈ 23 °C
- Discontinuous and compartmentalized interbedded sands and shales
- Thinly laminated and bioturbated (‘lam scrap’)
Core put into fresh water

Currently using high concentrations of KCL as clay stabilizer

Swelling Clays/Fines Migration
Fear of wax deposition in perforations has lead to hot water treatments in the area.
Fracture Treatment Stage Spacing versus Date

Viking Area Horizontal Well Stimulation – Fracturing Spacing Statistics
Production Analysis/Forecasting

• Start with Vertical Wells
  – Flow Regime Identification
  – Time to end of transient flow (start bounded flow)
    • What type of transient flow
  – Do we get more reserves when we infill drill?
  – Type curve for reserves determination
    • Methodology

• Horizontal Wells
  – Repeat vertical well workflow
Traditional semi-log plot seen everywhere
No ability to identify reservoir behavior (early or late time flow regimes)

Oil Production for Vertical North Plato Wells within one Section (Wells start in 1986 and 1987)
Harmonic Plot showing transient (upward curvature) then bounded flow (downward curvature)
No radial flow
Long term linear flow (≈ 3 years) then bounded flow

What causes linear flow?
1. Fracture (over in 30 days)
2. High aspect ratio flow units
   rectangle > 10:1 aspect ratio

Modified Fetkovich Plot - Vertical North Plato Wells
Hypothetical Geological explanation of production response
Higher the initial rate the higher the reserves

Why?
At any given rate the cumulative is higher for higher initial rate wells

No radial flow
Long term linear flow (≈ 3 years) then bounded flow

What causes linear flow?
1. Fracture (over in 30 days)
2. High aspect ratio flow units rectangle > 10:1 aspect ratio

Modified Fetkovich Plot - Vertical North Plato Wells
Type Curve (1)
Old Ideas

• Old ideas
  – Never allow $b>1$
  – Arbitrarily curve fit data
Physics based type curves

- Composite decline curves
  - Three Stems
  - Available in most software
Type Curve (2b)
My Recommendation

• Stem 1 - Transient Flow
  – $b > 1$ is indication of transient behavior
  – $b = 2$ is linear flow
  – time to end of transient flow = end of $b > 1$

• Stem 2 - Bounded Flow
  – $b$ for solution gas drive (single layer)
    • $b = 0.3$ Fetkovich
    • $0.4 < b < 0.5$ Ahmed and McKinney
  – $b$ for solution gas drive (multiple layer)
    • $0.5 < b < 1.0$ Fetkovich
  – It is my recommendation not to regress on $b$ but to assign $b$ after careful consideration

• Stem 3 - Terminal Decline (exponential decline)
  – How do you pick it?
  – Typically around 6% per year
Semi-Log Rate/Time – Type Curve Match 2 where late time b=0.6

Second pass match using b2=0.6
b2 > 0.5 is an indication of cross-flow from tight layers to main producing layers
Second pass match using $b_2=0.6$

$b_2 > 0.5$ is an indication of cross-flow from tight layers to main producing layers.

Fetkovich Plot – Type Curve Match 2 where late time $b=0.6$
Horizontal Wells
4th month rate is a good indicator of when the well goes on linear flow.

Early Dodsland Horizontal Multi-Stage Fractured Wells
Distribution of 4th month rates across Plato

Prior to hot water and KCL treatment changes

Paper done prior to any of those results being available
Range of initial rates

4 months flat rate then linear flow (b1=2.0). At time =850 days bounded flow (b2=0.7)
Infill Drilling

• Did infill drilling vertical wells add reserves?
• Find areas with highest well counts
  – Two half sections with the equivalent of 32 wells per section
Plato North
Map from mid-2012
Harmonic Plot for North Half of Section 36-026-20 W3M, North Plato Pool

16 Wells per ½ Section

More Reserves?
Very clearly ‘yes’ from
Group semi-log rate-cum plot
(The Harmonic Plot)
Infill Drilling Horizontal Wells
2014 Update

• Same region as last map
• Number of horizontal wells drilled into area
Blue Area corresponds to 16 wells per ½ section (32 wells per section) previously reviewed

2 horizontal wells drilled since 2012

Plato North
Map from 2014-05
Section 36-029-19 W3M
Blue Region

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Qo (4th Month)</th>
<th>Better Than % of Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>191 07-36-026-20W3M 00Prd</td>
<td>4.43</td>
<td>81.7</td>
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</table>

No production data yet
Blue Area corresponds to 16 wells per ½ section (32 wells per section) previously reviewed

2 horizontal wells drilled since 2012

Orange Area corresponds to 16 wells per section
Static pressures taken at vertical wells prior to infill drilling first horizontal well

7 horizontal wells drilled since 2012

Plato North
Map from 2014-05
Most vertical wells drilled in 1980’s
3 wells drilled between 1990 and 1992

Small amount of water injection at 03-02

Pool initial pressure = 6200 kPa
Pressures taken at producing wells in March 2012
(in green) Pavg = 1367 kPa

3 wells around injection well Pavg = 1451 kPa

First horizontal well initial pressure ~ 4500 kPa
**Strong indicator of upside potential**

<table>
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<tr>
<th>Well Name</th>
<th>Qo (4th Month)</th>
<th>Better Than % of Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>191 15-02-027-20W3M 00Prd</td>
<td>6.40</td>
<td>90.7</td>
</tr>
<tr>
<td>192 15-02-027-20W3M 00Prd</td>
<td>7.35</td>
<td>92.9</td>
</tr>
<tr>
<td>191 10-34-026-20W3M 00Prd</td>
<td>4.87</td>
<td>84.0</td>
</tr>
<tr>
<td>192 07-34-026-20W3M 00Prd</td>
<td>9.34</td>
<td>96.9</td>
</tr>
<tr>
<td>191 07-34-026-20W3M 00Prd</td>
<td>7.07</td>
<td>92.4</td>
</tr>
</tbody>
</table>

Horizontal wells in blue have available production data.
High Rate Wells

1. Better quality reservoir
2. Better completion technology

• How do you tell?
  – 5 plots are recommended for a preliminary diagnosis
Provost
Production Statistic is 4th month Oil Rate

Provost by Year, >= 3 Wells in Sample

Rate going up with time
Better areas or better technology?
Production Statistic is 4th month Oil Rate

Provost by Operator, >= 3 Wells in Sample

Cutpick is the best operator by far
Production Statistic is 4th month Oil Rate

Provost by Pool, >= 3 Wells in Sample

Note the C001 pool is the 3rd best pool with 72 wells
Cutpick is exclusively in the 3rd best pool
Total Samples = 72, Med=3.93 m3/d
Infer that Cutpick has better completion technology
Cutpick figured out how to complete wells right away
Found out that principals had prior experience in Viking with other companies
Recommended Dashboard Plot

One statistically significant pool
C001 – Cutpick Med=8.52, All Med=3.93
Case 1 - Conclusions

• Have shown
  – Type Curve development
  – Infill drilling analysis (vertical and horizontal) and post mortem
  – Identification of successful plays
  – Identification of successful companies

• But …
  – How do you compare various treatment strategies?
Case 2 - SPE 149331

Montney Gas

- Groundbirch area (gas)
  - Zone thickness 28.5 meters
  - Big slick water job
  - 67 tonnes per stage
  - 12 of 17 stages assumed to be flowing (based on PLT)

- Trying to determine via numerical simulation
  - Permeability
  - Fracture half length – $x_f$
  - Fracture Conductivity
Modified Fetkovich Plot Shows damaged linear flow

GroundBirch Production Comparisons QGC/Dm versus tmbg1

Gas Cum/Gas Rate

First Order Gas Material Balance Time (days)
Positive Y intercept indicates damaged linear flow

\[ \frac{1}{\text{Slope}} = LFP \sim k^{0.5}x_f \]
$C_{fd}=85.4$ is close to infinity
Still significant positive skin on well
Flow convergent skin, which is unique to horizontal wells, is significant
Case 2 - SPE 149331
Montney Gas
Conclusions

• Even though $C_{fd}$ is ‘infinite’ there is still considerable positive skin

• Positive skin due to ‘flow convergence’ within fracture to perforations
  – Prevalent in thicker formations
  – Further improving fracture conductivity would reduce ‘flow convergence’ skin
Case 3 - SPE 168632
Montney Gas
Comparing Slickwater to CO2 Foam

- RTA study (50 wells)
- Determine fracture properties + reservoir permeability
- Slick water treatments
  - Low viscosity treatments
  - Create more complex fracturing (SRV)
- Foam base treatments
  - Lower water usage
  - High viscosity
  - Better proppant carrying capacity
  - Potential for higher fracture propped width and conductivity
Study Overview – Heritage Area

Well Locations within Study

- Pouce Coupe
- Glacier
Montney Heritage Area
Comparing Slickwater to CO2 Foam

CO2 foam gives superior fracture properties with less proppant as compared to slickwater

For CO2 foam, more proppant per stage at high proppant concentration has positive effect

CO2 foam gives superior fracture properties with less fluid as compared to slickwater

For CO2 foam, more fluid per stage (lower overall proppant concentration) has negative effect
Case 3 - SPE 168632
Montney Gas
Conclusions

• Different fracturing processes can be compared
  – Effect of reservoir permeability removed
• CO2 foam fracture fluids are superior to slickwater