Pre-Frac Injection Tests

R.D. Barree
In this session ...

• Discuss DFIT requirements and procedures
  – Look at SRT Analysis
    – Pressure loss at Perfs
    – Near-Wellbore Pressure Loss
  – Look at Post Shut-In Analysis
  – discuss G-function analysis in detail
    • Importance of correct determination of closure
    • Pore pressure and permeability
    • Efficiency and Leakoff
    • Discuss the effects of Variable Storage and Tip Extension
Diagnostic Fracture Injection Test: DFIT

**Requirements:**

- **Data Acquisition**
  - 0.01-0.1 psi resolution surface gauge
  - Record all rates and pressures at 1/sec sampling rate
  - Injection schedule must be precisely recorded

- **Use Newtonian, non-wall building fluid (water, oil, or N2).**

**Procedure:**

- Bring rate to max
- Pump for 2-5 minutes
- Rapid step-down to get WHP at each rate
- Isolate wellhead
- Shut-down for 90 minutes (minimum) or up to 48 hrs

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Pre-Frac Injection/Falloff Tests

Why pre-frac test?

• obtain specific data
  – Characterize the reservoir and completion
• every pump-in carries risk of damage
  – testing procedure must be designed to minimize damage

Types:

• Step-rate injections
  – pipe and near-well friction
  – # of effective perfs open
  – frac extension pressure
• Pressure falloff after shut-in
  – frac closure pressure
  – fluid efficiency and leakoff coefficient
  – fracture closure mechanism

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Application of Pre-Frac Tests

- Calibration of logs:
  - Total closure stress
  - Mechanical properties
  - Tectonic strain and stress
- Net fracture extension pressure
  - Frac width
  - Height containment
  - Created fracture length and width
- Leakoff
  - Pad volume requirements
  - Maximum sand concentration
- Overall design
  - Expected pack concentration
  - Final fracture conductivity
  - Necessary frac length for optimum stimulation

If you’re going to do this, you’d better do it right!
Pre-Frac Step-Rate Injection Test
Traditional Step Rate Test (SRT) Analysis
System Friction Analysis from SRT Data

- Step-down data preferred
  - pressure response to rate changes should be related to frictional components
- Requires accurate pipe friction estimate
- Additional rate-dependent pressure drop caused by
  - perforation
    - Square of the rate
  - near-well flow restriction
    - Square root of rate
Wellbore Pressure Calculations

Np=38, d=0.32", Cd=0.75
Resolving Components of Friction

• Pipe friction
  – Generally varies with rate\(^2\) in turbulent flow
  – Must know the pipe friction to separate it from BH and near-well friction

• Perf friction
  – Varies with rate\(^2\)
  – Changes with sand injection
    • CD change and perf rounding
    • Diameter change and perf erosion

• Tortuosity
  – Varies with rate\(^{0.5}\) (or some other factor)
  – Some restriction that dissipates with injection rate
Pipe Friction Estimates

Water
Slick-water (FR)
20# Linear gel
40# gel
Gelled Oil
70Q N2 Foam

Data calculated for 2-7/8” tubing
Perforation Restriction Causes Large Pressure Drop

• Correct number & size of perfs can be estimated
• Pressure drop should be at least 100-200 psi more than the confining stress between zones
• Also depends on coefficient of discharge (C_D)
  – Jet perfs: 0.754; Bullets: 0.822
  – higher value indicates more efficient perf

\[
P_{pf} = \frac{1.975q^2 \rho_f}{C_D N_p d_p^4}; \text{psi}
\]
Tortuosity: Near-Wellbore Pressure Loss

- Stress halo around perf
- Flow around cement micro-annulus
- Perforation interference
- Narrow fracture width
- Fracture turning and branching (multiples)
- Off-vertical fractures
- Pulverized cement debris
- Charge debris
- Leakoff into drilling and perf induced fracs
Current SRT Spreadsheet

Hydraulic Fracture Step-Rate Diagnostics

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<thead>
<tr>
<th>Dtub(in)</th>
<th>TVD(ft)</th>
<th>Cd</th>
<th>Vtub(gal)</th>
<th>n'</th>
<th>k'</th>
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<td>CSxg=0.05</td>
<td>WH-ISIP(psi)=3002</td>
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<th>PPG@surf</th>
<th>BHP</th>
<th>dPfr(psi)</th>
<th>dPperf</th>
<th>dP tort</th>
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Post Shut-In: What is G-function Analysis?

- Post shut-in pressure decline analysis using dimensionless function
- Extends the analysis through use of the first derivative and semi-log derivative of BHP (dP/dG and GdP/dG)
- Also uses the characteristic shapes of derivative curves to locate specific modes of pressure decline
- Extension to After-Closure Analysis (ACA) to define reservoir linear and pseudo-radial flow
G-function Analysis in Pre-Completion Decision Making

• Estimate pore pressure
  – Is the zone depleted, normally pressured or over-pressured
  – Impacts reserve estimates and cleanup

• Detection of natural fractures
  – Significance to fracture placement
  – Do they impact flow performance?

• Estimation of permeability

• Determine leakoff mechanism and magnitude

• Combine reservoir and fracture data to make realistic estimates of post-frac rate
Algebraic Definition of the G-Function

G-function is a dimensionless function of shut-in time normalized to pumping time:

\[ G(\Delta t_D) = \frac{4}{\pi} \left( g(\Delta t_D) - g_0 \right) \]

\[ \Delta t_D = \frac{(t - t_p)}{t_p} \]
G-Function: Two limiting cases

- **Low Leakoff, high efficiency**
  - Fracture area open varies approximately linear with time
    \[ (\alpha = 1.0) \]
    \[
g(\Delta t_D) = \frac{4}{3} \left( (1 + \Delta t_D)^{1.5} - \Delta t_D^{1.5} \right)
\]

- **High leakoff, low efficiency**
  - Fracture area varies with square-root of time
    \[ (\alpha = 0.5) \]
    \[
g(\Delta t_D) = (1 + \Delta t_D) \sin^{-1}\left(\left(1 + \Delta t_D\right)^{-0.5}\right) + \Delta t_D^{0.5}
\]
Falloff Analysis Methods

- Observed shut-in pressure versus square-root of shut-in time (Sqrt(t) Plot)
  - Use of diagnostic derivatives on Sqrt(t) plot
- G-Function and its diagnostic derivatives
- Log-Log plot of pressure change after shut-in versus time after shut-in

After Closure analyses to define reservoir properties:
  - Flow regime identification
  - Horner analysis
  - Talley-Nolte method
Evaluated Pressure Falloff Cases

1. Fracture extension after shut-in
2. Constant leakoff in a well-confined fracture with tip recession during closure
3. Pressure dependent leakoff
4. Pressure dependent leakoff and modulus
5. Leakoff with variable storage or fracture compliance (transverse storage)
Ambiguous Closure Using Sqrt(t) Analysis

Which one is closure?
Normal Leakoff G-Function

- P vs. G
- Fracture Closure
- GdP/dG vs. G
- dP/dG vs. G
Sqrt(t) Plot for Normal Leakoff

Pressure vs. sqrt(t)
Fracture Closure
sqrt(dp/dsqrt(t)) vs. sqrt(t)
dP/sqrt(t) vs. sqrt(t)
Log-Log Plot for Normal Leakoff

BH ISIP = 9998 psi

Delta-Pressure and Derivative

Time (0 = 8.15)

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### Summary of Characteristic Slopes on Log-Log Plot

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<thead>
<tr>
<th>Log-Log Graph</th>
<th>Before Closure</th>
<th>After Closure</th>
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<td>Linear</td>
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<td>$\Delta p_{awf}$ vs. $t_a$</td>
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<td>—</td>
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<tr>
<td>$\partial \Delta p_{wf} / \partial t$ vs. $t$</td>
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<td>$-1/2$</td>
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<tr>
<td>$\partial \Delta p_{awf} / \partial t_a$ vs. $t_a$</td>
<td>$1/4$</td>
<td>$1/2$</td>
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<tr>
<td>$t \partial \Delta p_{wf} / \partial t$ vs. $t$</td>
<td>$5/4$</td>
<td>$3/2$</td>
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<tr>
<td>$t^2 \partial \Delta p_{awf} / \partial t_a$ vs. $t_a$</td>
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Fracture and Reservoir Transient Flow Regimes

Fracture Linear Flow
(Tip-Extension, ½ slope)

Bi-Linear Flow (Before closure, ¼ slope
After closure, -3/4 slope)

Formation Linear Flow
(Before closure, ½ slope
After closure, -½ slope)

Pseudo-Radial Flow
(After closure, -1 slope)
After-Closure Flow Regime Plot

\[ \Delta P = (p_w - p_r) \]

\[ F_L^2 \frac{d\Delta P}{dF_L^2} \text{ vs. } F_L^2 \]

\[ \Delta P \text{ vs. } F_L^2 \]

Start of Radial Flow

\[ m = 1 \]
RESULTS:
Reservoir Pressure = 7475.68 psi
Transmissibility, \( \frac{kh}{\mu} = 298.94991 \) md*ft/\( \mu \)h
Permeability, \( k = 0.0968 \)
Start of Pseudo Radial Time = 2.15 hours
Horner Analysis: Only Valid in Pseudo-Radial Flow

\[ \frac{kh}{\mu} = \frac{162.6(1440)q}{m_H} \]

- \( q \): bpm
- \( k \): md
- \( m_H \): psi\(^{-1}\)
- \( h \): ft
- \( \mu \): cp

- \( P^* = 7476 \) psi
- \( \frac{kh}{\mu} = 298 \) md-ft/cp
- \( kh = 7.9 \) md-ft
- \( k = 0.097 \) md
Permeability Estimation from G at Closure $\left( G_c \right)$

- Good estimate when after-closure radial-flow data not available

\[
k = \frac{0.0086 \mu \sqrt{0.01 P_z}}{\phi c_t \left( \frac{G_c E r_p}{0.038} \right)^{1.96}}
\]

Where:

- $k$ = effective perm, md
- $\mu$ = viscosity, cp
- $P_z$ = process zone stress or net pressure
- $\phi$ = porosity, fraction
- $c_t$ = total compressibility, 1/psi
- $E$ = Young’s Modulus, MMpsi
- $r_p$ = leakoff height to gross frac height ratio
Permeability Estimate from G-at-Closure - Illustrated

Estimated Permeability = 0.0974 md

Data Input

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<th>Parameter</th>
<th>Value</th>
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<td>$P_z$</td>
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Computation of Efficiency and Leakoff Coefficient

• Efficiency is given by:

\[ \eta = \frac{G_c}{2 + G_c} \]

• Leak-off is given by:

\[ C_L = \frac{2h}{\pi r_p E \sqrt{t_p}} \frac{dP}{dG} \]

These equations are only valid with no pressure dependent behavior during closure.
Typical PDL Behavior of G-Function Derivatives

- Pressure vs. G
- Fracture Closure
- End PDL
- GdP/dG vs. G
- dP/dG vs. G

G(Time)

Pressure
Log-Log Plot for PDL Example

BH ISIP = 10000 psi

- **ΔP vs. Δt**
- **Linear Flow**
- **Radial Flow**
- **Fracture closure**
- **ΔtdΔP/dΔt vs. Δt**

Pressure Difference and Derivative

Time (0 = 9.133333)
Sqrt(t) Plot for PDL Example

- False Closure
- P vs. √t
- Fracture Closure
- √tdP/d√t vs. √t
- dP/d√t vs. √t
Estimation of PDL Coefficient from Falloff Data

Leakoff coefficient can be estimated from the ratio of $dP/dG$ before and after fissure closure.

$$\frac{C_p}{C_o} = \left(\frac{dP}{dG}\right)_{P > P_f} / \left(\frac{dP}{dG}\right)_{P < P_f}$$

or

$$\ln\left(\frac{C_p}{C_o}\right) = C_{dp} \Delta P$$

Bottomhole Pressure, psi

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Determination of PDL Coefficient

Bottom Hole Pressure (psi)

\[ \ln(Cp/Co) \]

(Fissure Opening Pressure = 9311)

(PDL Coefficient = 0.0019)
Natural Fracture System in Hard-Rock

\[ \sigma_{H\text{min}} \]

\[ \sigma_{H\text{max}} \]
Fissures Opened By Tensile Stress Field

\[ \frac{d_f}{x_f} \leq \frac{1}{2} \left[ \frac{(P_f - S_h)}{(T + S_h)} \right]^2 \]

Typical leakoff volume:
- 0.05 ft³/ft² each face
- 3” depth in 20% \( \phi \) rock
- 10’ depth in 1/2% \( \phi \) fractures

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Width of Fracture Zone for Various Half-Lengths
(Sh=5000 psi, Tn=1000 psi)
Using best straight-line extrapolation to closure:

Computed efficiency = 0.48
Actual efficiency (simulator) = 0.28

Using 75% rule:
Computed efficiency = 0.35
G-Function Analysis for Leakoff with Variable Storage

- P vs. G
- Fracture Closure
- GdP/dG vs. G
- dP/dG vs. G

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Sqrt(t) Plot for Leakoff with Variable Storage

- P vs. \( \sqrt{t} \)
- Fracture Closure
- \( \sqrt{t}dP/d\sqrt{t} vs. \sqrt{t} \)
- \( dP/d\sqrt{t} vs. \sqrt{t} \)
Variable Storage Signature on the Log-Log Plot

Delta-Pressure and Derivative

ΔP vs. Δt

ΔtΔP/dΔt vs. Δt

BH ISIP = 10000 psi

Time (0 = 9.416667)
Fracture Height Recession and Transverse Storage

Leakoff through a thin permeable layer:
Decreasing storage relative to leakoff rate accelerates pressure decay

Expulsion of fluid from transverse fractures:
Maintains pressure in fracture until fissures close
Closure-Time Correction for Variable Storage

\[ r_p = \frac{\int_0^{G_c} G \frac{\partial P}{\partial G}}{0.5G_c^2 \left( \frac{\partial P}{\partial G} \right)_c} \]

Pressure Derivative vs. G(Time)

- \((G\partial P/\partial G)_c\)
- \(G_c\)
Permeability Estimate with Storage Correction

Mini-Frac Permeability = 0.0617 md

Data Input

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<th>Value</th>
<th>Unit</th>
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Tip-Extension G-Function Analysis

Graph showing:
- $P$ vs. $G$
- $GdP/dG$ vs. $G$
- $dP/dG$ vs. $G$
Sqrt(t) Plot for Tip-Extension

- Incorrect Closure
- dP/d√t vs. √t
- P vs. √t
- √t dP/dt vs. √t

Pressure vs. Time (1/25/2007)
Log-Log Plot for Tip-Extension

ΔP vs. Δt

ΔtdΔP/dΔt vs. Δt

BH ISiP = 10000 psi

Time (0 = 33.7)
Potential Problems in Pressure Diagnostics

- **Bad ISIP**
  - Extreme perf restriction
  - Wellbore fluid expansion

- **Zero surface pressure during falloff**
  - Falling fluid level
  - Non-zero sandface rate
  - Partial vacuum above fluid column

- **Gas entry to closed wellbore**
  - Phase segregation

- **Use of gelled (wall-building) fluid**
  - Disruption of after-closure pressure gradients
  - Masking of reservoir flow capacity
Example of Ambiguous ISIP Caused by Near-Well Restriction

GohWin Pumping Diagnostic Analysis Toolkit
Job Data

Minifrac Events
<table>
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<tr>
<th></th>
<th>Time</th>
<th>BHP</th>
<th>SR</th>
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<td>0.990</td>
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<td>00:10:31</td>
<td>57469</td>
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<tr>
<td>3</td>
<td>04:37:46</td>
<td>45868</td>
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ISIP=80000
BHP G-function for Early ISIP Shows Apparent “PDL”

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - G Function

<table>
<thead>
<tr>
<th></th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
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<tbody>
<tr>
<td>Bottom Hole Pressure (kPa)</td>
<td>G(Time)</td>
<td></td>
<td>Bottom Hole Pressure (kPa)</td>
<td></td>
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<tr>
<td>Smoothed Pressure (kPa)</td>
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<td>Bottom Hole Pressure (kPa)</td>
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<td></td>
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<tr>
<td>1st Derivative (kPa)</td>
<td></td>
<td></td>
<td>1st Derivative (kPa)</td>
<td></td>
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<tr>
<td>G*dP/dG (kPa)</td>
<td></td>
<td></td>
<td>G*dP/dG (kPa)</td>
<td></td>
</tr>
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</table>

Time  | BHP  | SP   | DP   | FE   |
------|------|------|------|------|
End of Test | 20.29 | 45908 | 45907 | 25457 | 91.53 |
Late ISIP G-Function Suppresses “PDL Hump”

GohWin Pumping Diagnostic Analysis Toolkit
Minifract - G Function

Bottom Hole Pressure (kPa) A
1st Derivative (kPa) D
G*dP/dG (kPa) D

<table>
<thead>
<tr>
<th>Time</th>
<th>BHP</th>
<th>SP</th>
<th>DP</th>
<th>FE</th>
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<td>45924</td>
<td>11047</td>
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Bottom Hole Pressure (kPa)

1st Derivative (kPa)

G*dP/dG (kPa)

Time Closure 19.43

BHP 45928

SP 45924

DP 11047

FE 91.19
Early ISIP Log-Log Plot Shows Increased Separation and Long Negative Derivative Slope

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - Log Log

Delta Bottom Hole Calc Pressure (kPa)  A
Delta Smoothed Pressure (kPa)  A
Smoothed Adaptive 1st Derivative (kPa/min)  B
Adaptive DTdDP/dDT (kPa)  A

BH ISIP = 71366 kPa

End of Test Time 264.72
DBHCP 25457
DSP 25458
FE 91.53

7x Separation

(Y = 3734) (m = 0.506)
(Y = 3134)
(Y = 421.8)
(Y = 3734)
(Y = 421.8)
Late ISIP Log-Log Plot Gives Consistent Separation

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - Log Log

- Delta Bottom Hole Calc Pressure (kPa)
- Delta Smoothed Pressure (kPa)
- Smoothed Adaptive 1st Derivative (kPa/min)
- Adaptive DTdDP/dDT (kPa)

BH ISIP = 56975 kPa

Time DBHCP DSP FE
1 Closure 260.51 11037 11037 91.17

(41.34, 1853)
(Y = 410.3)
(Y = 2956)
(41.34, 1853)
(m = 0.25)
BHP Gauge Data with Falling Fluid Level

GohWin Pumping Diagnostic Analysis Toolkit

Job Data

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<thead>
<tr>
<th>Time</th>
<th>BGP</th>
<th>SR</th>
</tr>
</thead>
<tbody>
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<td>10/2/2006 19:19:03</td>
<td>6393</td>
</tr>
<tr>
<td>2 Shut In</td>
<td>10/2/2006 19:35:34</td>
<td>4368</td>
</tr>
<tr>
<td>3 Stop</td>
<td>10/2/2006 23:23:40</td>
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BH Gauge Pressure (psi)  Slurry Rate (bpm)

Start
Shut In
Stop

(ISIP = 4366)
Long-Term Falloff with BHP Gauges and Falling Fluid Level

GohWin Pumping Diagnostic Analysis Toolkit
Job Data

<table>
<thead>
<tr>
<th>Minifrac Events</th>
<th>Time</th>
<th>BGP</th>
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<tr>
<td>2</td>
<td>Shut In 10/2/2006 19:35:34</td>
<td>4368</td>
<td>0.000</td>
</tr>
<tr>
<td>3</td>
<td>Stop 10/2/2006 23:23:39</td>
<td>3027</td>
<td>0.000</td>
</tr>
</tbody>
</table>

Graph showing BH Gauge Pressure (psi) and Slurry Rate (bpm) over time from 10/3/2006 to 10/7/2006.
Effect of Falling Fluid Level on G-Function Derivative Plot

GohWin Pumping Diagnostic Analysis Toolkit

Minifrac - G Function

- BH Gauge Pressure (psi)
- Smoothed Adaptive 1st Derivative (psi)
- Smoothed Adaptive G*dP/dG (psi)

<table>
<thead>
<tr>
<th>Time</th>
<th>BGP</th>
<th>SP</th>
<th>DP</th>
<th>FE</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.36</td>
<td>3423</td>
<td>3439</td>
<td>913.5</td>
<td>73.99</td>
</tr>
</tbody>
</table>
Effect of Falling Fluid Level on Log-Log Diagnostic Plot

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - Log Log

Delta Bottom Hole Calc Pressure (psi)
Smoothed Adaptive 1st Derivative (psi/min)
Adaptive DTdDP/dDT (psi)

BH ISIP = 4352 psi

Time (0 = 1175.566667)

<table>
<thead>
<tr>
<th>Time</th>
<th>DBHCP</th>
<th>DSP</th>
<th>FE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Closure</td>
<td>123.46</td>
<td>929.1</td>
<td>912.6</td>
</tr>
</tbody>
</table>
Effect of Falling Fluid Level on ACA Log-Log Linear Plot

GohWin Pumping Diagnostic Analysis Toolkit
ACA - Log Log Linear

Results
Start of Pseudo Linear Time = 71.87 min
End of Pseudo Linear Time = 98.57 min
Start of Pseudo Radial Time = 110.06 hours

Analysis Events

<table>
<thead>
<tr>
<th></th>
<th>Start of Pseudoradial Flow</th>
<th>BGP</th>
<th>Slope</th>
<th>(p-pi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td></td>
<td>0.01</td>
<td>2777</td>
<td>0.00</td>
</tr>
<tr>
<td>2</td>
<td></td>
<td>0.32</td>
<td>3028</td>
<td>0.00</td>
</tr>
<tr>
<td>1</td>
<td></td>
<td>0.37</td>
<td>3093</td>
<td>0.00</td>
</tr>
</tbody>
</table>

Square Linear Flow (FL^2)

Moving Avg Of Slope (psi)
Effect of Falling Fluid Level on ACA Linear Flow Plot

GohWin Pumping Diagnostic Analysis Toolkit
ACA - Cartesian Pseudolinear

Analysis Events

<table>
<thead>
<tr>
<th>Event Description</th>
<th>LFTF</th>
<th>BGP</th>
</tr>
</thead>
<tbody>
<tr>
<td>End of Pseudolinear Flow</td>
<td>0.56</td>
<td>3028</td>
</tr>
<tr>
<td>Start of Pseudolinear Flow</td>
<td>0.61</td>
<td>3093</td>
</tr>
</tbody>
</table>

Results

- Reservoir Pressure = 2296.52 psi
- Start of Pseudo Linear Time = 71.87 min
- End of Pseudo Linear Time = 98.57 min

BH Gauge Pressure (psi)

(m = 1297.8)
Pressure Increase Caused by Gas Entry and Phase Segregation
Pressure Increase from Rising Gas Bubbles

\[ P_2 = P_1 = \frac{zNRT}{V} \]

\[ P_1 = P_{\text{head}} = \frac{zNRT}{V} \]

\( P_{\text{head}} = 0.45 \text{ psi/ft} \)
Early-Time WHP G-function Analysis

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - G Function

- Bottom Hole Calc Pressure (psi)
- Smoothed Pressure (psi)
- 1st Derivative (psi)
- G*dP/dG (psi)

<table>
<thead>
<tr>
<th>Time</th>
<th>BHCP</th>
<th>SP</th>
<th>DP</th>
<th>FE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Closure</td>
<td>1.00</td>
<td>7192</td>
<td>7202</td>
<td>1182</td>
</tr>
</tbody>
</table>

Graph showing various pressure and derivative functions over time.
Effect of Gas Entry and Phase Segregation on G-Function

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - G Function

- Bottom Hole Calc Pressure (psi)
- Smoothed Pressure (psi)
- 1st Derivative (psi)
- G*dP/dG (psi)

<table>
<thead>
<tr>
<th>Time</th>
<th>BHCP</th>
<th>SP</th>
<th>DP</th>
<th>FE</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>7192</td>
<td>7212</td>
<td>1190</td>
<td>34.54</td>
</tr>
</tbody>
</table>

Bottom Hole Calc Pressure: 7192 psi
Smoothed Pressure: 7212 psi
1st Derivative: 1190 psi
G*dP/dG: 34.54 psi

Closure Time: 1.00
Effect of Gas Entry and Phase Segregation on Log-Log Plot

GohWin Pumping Diagnostic Analysis Toolkit
Minfrac - Log Log

- Delta Bottom Hole Calc Pressure (psi)
- Delta Smoothed Pressure (psi)
- 1st Derivative (psi/min)
- DTdDP/dDT (psi)

<table>
<thead>
<tr>
<th>Time</th>
<th>DBHCP</th>
<th>DSP</th>
<th>FE</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Closure</td>
<td>5.31</td>
<td>1185</td>
</tr>
</tbody>
</table>

BH ISIP = 8377 psi

(11.41, 922.9)
(77.1, 355)
(Y = 96.55)
Effect of Gas Entry and Phase Segregation on ACA Log-Log Plot

ACA - Log Log Linear

Analysis Events

<table>
<thead>
<tr>
<th>Event Description</th>
<th>SLF</th>
<th>BHCP</th>
<th>Slope (p-pi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start of Pseudoradial Flow</td>
<td>3</td>
<td>5280</td>
<td>297.5</td>
</tr>
<tr>
<td>End of Pseudolinear Flow</td>
<td>2</td>
<td>5617</td>
<td>652.2</td>
</tr>
<tr>
<td>Start of Pseudolinear Flow</td>
<td>1</td>
<td>6103</td>
<td>913.1</td>
</tr>
</tbody>
</table>

Slope (psi) (p-pi) psi

Results
Start of Pseudo Linear Time = 11.88 min
End of Pseudo Linear Time = 28.70 min
Start of Pseudo Radial Time = 17.37 hours
Effect of Gas Entry and Phase Segregation on ACA Linear Plot

GohWin Pumping Diagnostic Analysis Toolkit

ACA - Cartesian Pseudolinear

Analysis Events

<table>
<thead>
<tr>
<th></th>
<th>LFTF</th>
<th>BHCP</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>0.38</td>
<td>5617</td>
</tr>
<tr>
<td>1</td>
<td>0.52</td>
<td>6103</td>
</tr>
</tbody>
</table>

Results

- Reservoir Pressure = 4279.89 psi
- Start of Pseudolinear Flow = 11.88 min
- End of Pseudolinear Flow = 28.70 min

Bottom Hole Calc Pressure (psi)

Linear Flow Time Function
Effect of Gas Entry and Phase Segregation on ACA Radial Plot

Results
- Reservoir Pressure = 4894.94 psi
- Transmissibility, \( \frac{kh}{\mu} = 87.73613 \text{ md*ft/cp} \)
- Permeability, \( k = 0.0495 \text{ md} \)
- Start of Pseudo Radial Time = 17.37 hours

Analysis Events
- BHTF BHCP
  - Start of Pseudo Radial Flow

GohWin Pumping Diagnostic Analysis Toolkit
ACA - Cartesian Pseudoradial
Pressure Decay without Filter-Cake: One-Dimensional Transient Flow

Distance from frac face

$P_{\text{frac}}$

$P_{\text{pore}}$
Impact of Resistances in Series

\[ \Delta P_3 = L_3/k_3 \quad + \quad \Delta P_2 = L_2/k_2 \quad + \quad \Delta P_1 = L_1/k_1 \quad = \quad \Delta P_T \]

\[ K_{\text{avg}} = \frac{L_t}{L_1/k_1 + L_2/k_2 + L_3/k_3} = 0.025 \]
Frac Fluid Loss: Discontinuous Pressure Gradient with Filtercake

With filtercake pressure gradient is discontinuous and far-field gradient is not related to leakoff rate through reservoir permeability.

Distance from frac face

\[ P_{\text{frac}} \]
\[ P_{\text{pore}} \]
Recall: Complete Stress Equation

\[ P_c = \frac{\nu}{(1 - \nu)} \left[ P_{ob} - \alpha_v P_p \right] + \alpha_h P_p + \varepsilon_x E + \sigma_t \]

- \( P_c \) = closure pressure, psi
- \( \nu \) = Poisson’s Ratio
- \( P_{ob} \) = Overburden Pressure
- \( \alpha_v \) = vertical Biot’s poroelastic constant
- \( \alpha_h \) = horizontal Biot’s poroelastic constant
- \( P_p \) = Pore Pressure
- \( \varepsilon_x \) = regional horizontal strain, microstrains
- \( E \) = Young’s Modulus, million psi
- \( \sigma_t \) = regional horizontal tectonic stress
Estimation of Pore Pressure & Flow Capacity

- Horner plot is only valid in pseudo-radial flow
- Short-term after-closure data can be misleading
- In linear flow, $\frac{1}{2}$ slope and 2x factor between $DP$ and $DP'$ is diagnostic
- Pore pressure can be obtained from the linear flow period
- Reservoir $kh$ can be determined when radial flow is identified
- Pore pressure is related to closure stress
Conclusions:

• G-function response in low perm, hard rock is definitive and relatively easily interpreted
• Closure pressure and leakoff mechanism can be defined
• Natural fractures and their stress state can be determined
• Closure pressure is related to reservoir pore pressure
• Correlations between Gc and production can be developed for clean fluid (acid and/or water) injection tests
• Extended falloff data can be used for pseudo radial flow analysis of perm