PMG PETRO MANAGEMENT GROUP LTD.

Applications of Mini Fracs

DFIT - Diagnostic Fracture Injection Test

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For information:
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2015

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Quality Petroleum Engineering Consultants

Services:

- Reservoir Studies (Conventional/Simulation)
- Well Test Planning and Analysis
- Waterflood Design & Performance Monitoring
- Production Optimization
- Performance Evaluation of MFHW's (PTA, RTA, Numerical)
- Reserves and Economic Evaluations
- Complete frac design/optimization (Gohfer/KAPPA software)
- Government Submissions
- Customized course contents
- Expert Witness

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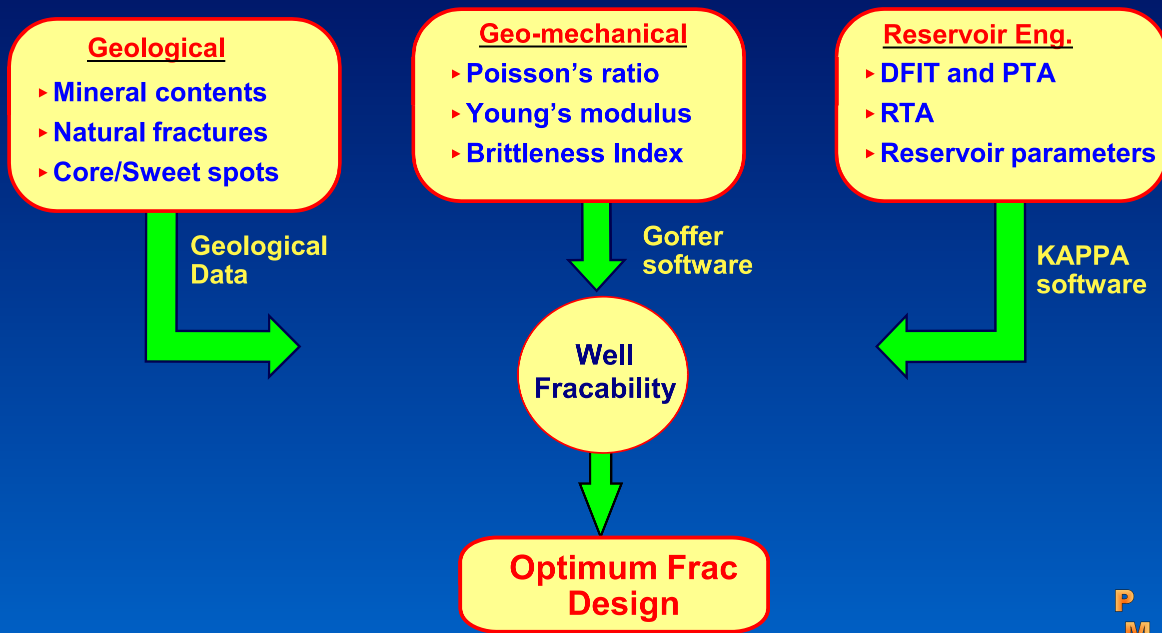
Petro Management Group - FracKnowledge

Full Well Frac Design and Optimization Services:



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Complimentary lunch and Learn Seminars

- Challenges of Reserves Estimate for tight and unconventional reservoirs - (Feb. 24)
- Waterflood Application for MFHW's - (March 25)
- Applications of Mini Frac (DFIT) - (May 7th)
- Performance Evaluation of Multi-Stage fracs Hz Wells (MFHW's) - (June 18)
- How to get the Most out of Well Testing
- Frac Databases: benefits to improve frac results
- How can we improve your frac design/performance in this poor oil price environment

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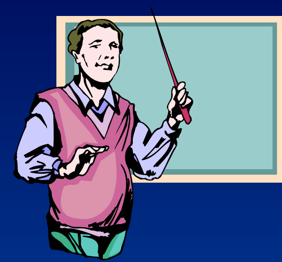
Industry and In-house Training Courses

- Fundamentals of Reservoir Engineering
- Well Test Analysis Workshop
- Performance Evaluation of Horizontal Wells
- Waterflood Management
- Enhanced Oil Recovery
- Petroleum Engineering for Non-Engineers



Benefits of in-house training:

- Up to 60% discount off the industry standard fees
- Customization
- Confidentiality

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Applications of Mini Fracs

DFIT - Diagnostic Fracture Injection Test

Agenda:

- Introduction
- Applications/benefits
- Types of DFIT analyses
  - Pre-Frac Closure
  - After Closure Analysis (ACA)
- Case study (Duvernay Shale Gas)
- Case study from Haynesville shale gas

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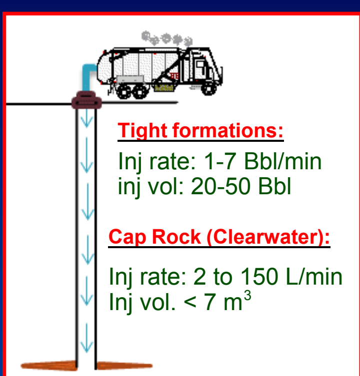
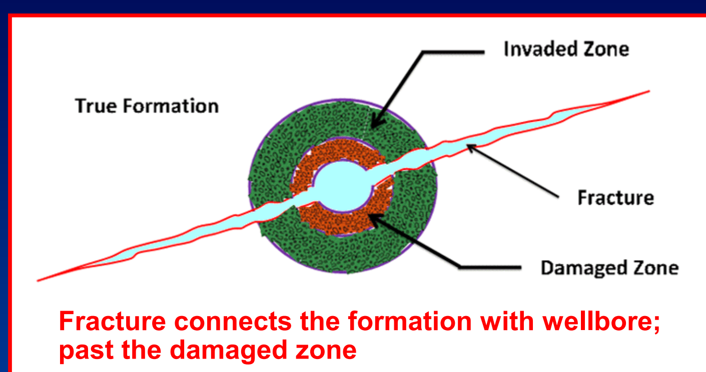
Why Conduct a Mini Frac Test?

- Estimate reservoir parameters needed for frac design
  - Formation permeability
  - Reservoir Pressure
- Other reservoir parameters (fluid leakoff, natural fractures)
- Environmental reasons; determine ceiling injection pressure of the cap rock for (AER requirement) for:
  - Steam-flooding projects
  - Water disposal/injection projects
- Optimize water/fluid injection in EOR schemes
  - Avoid **over-injection** (over the frac pressure)
  - Avoid **under-injection** (much lower than the frac pressure)
- Optimize drawdown during flowback to avoid frac damage

Mini Frac Test





- Short injection test (5 to 15 min.), followed by a few hrs of fall-off period
- Formation is broken down to allow wellbore/formation communication past the damaged zone
- No proppant is used
- Specialized low-rate injection pump, with automated flow rate control by means of a DCS (Digital Control System)
- Provides better results than closed chamber tests

Information Obtained from DFIT

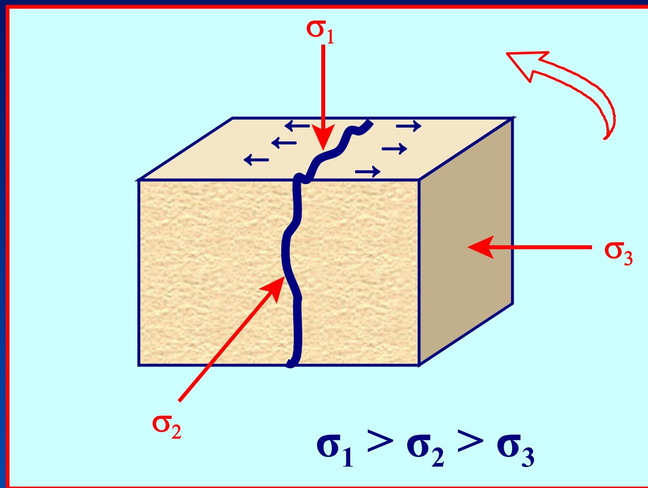
- **Obtain information critical to frac design:**
  - Fracture Propagation Pressure
  - Instantaneous Shut-in Pressure (ISIP)
  - Fracture Gradient (ISIP/depth)
  - Fracture Closure pressure (FCP)
  - Identify leakoff mechanism - leakoff coefficient
- **Identify flow regimes, to confirm reservoir parameters**:
  - Reservoir pore pressure
  - Formation flow capacity/mobility and Permeability
- **Net Fracture Pressure (NFP)**
  - Fracture complexity
  - Fracture progress/monitoring
  - Well flowback planning
- **Determine completion efficiency (step-down rate test)**
  - Pressure drop in perforation
  - Pressure drop as a result of well tortuosity

Limitations of DFIT

- Performed under injection conditions. Permeability will tend to be slightly higher than under drawdown conditions (stress-sensitive permeability).
- Short tests will provide upper bound for pore pressure
- Low pressure reservoirs problematic for surface pressure monitoring; would require bottomhole shut-in and gauges

Fracture Orientation is Controlled by In- Situ Stress Field

Vertical fracture



Where:

- σ_1 : Overburden stress
- σ_2 : Principle (max. stress)
- σ_3 : Minimum stress (closure stress)

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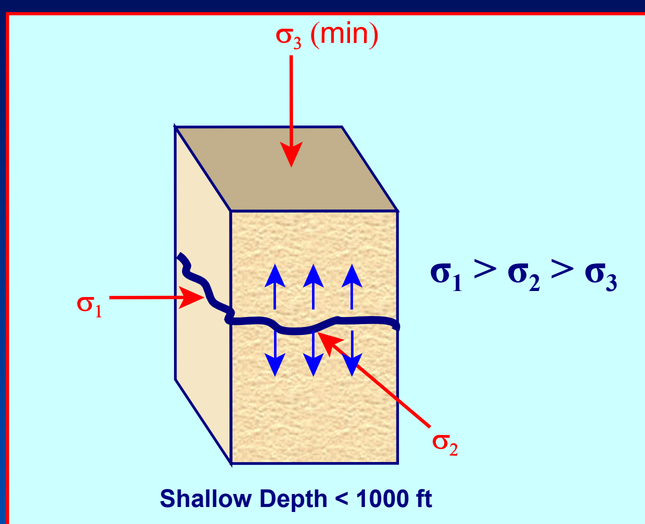
Fracture Orientation is Controlled by In- Situ Stress Field

Horizontal fracture



Where:

- σ_1 : Principle (max) horizontal stress
- σ_2 : Minimum horizontal stress
- σ_3 : Overburden pressure (Lowest stress)

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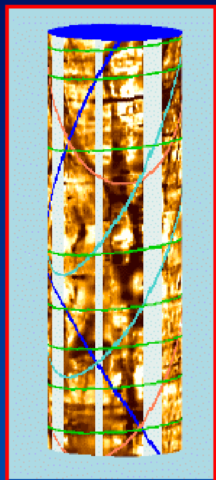
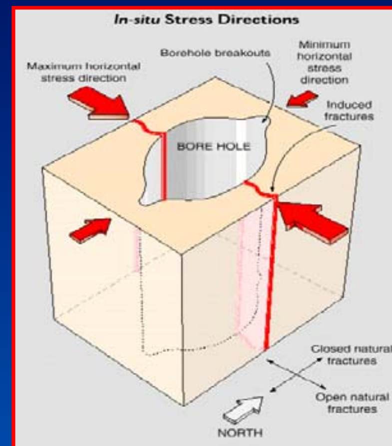
How to Determine Stress Direction?



FMI log
Fracture Micro-
Image Log



Calliper logs

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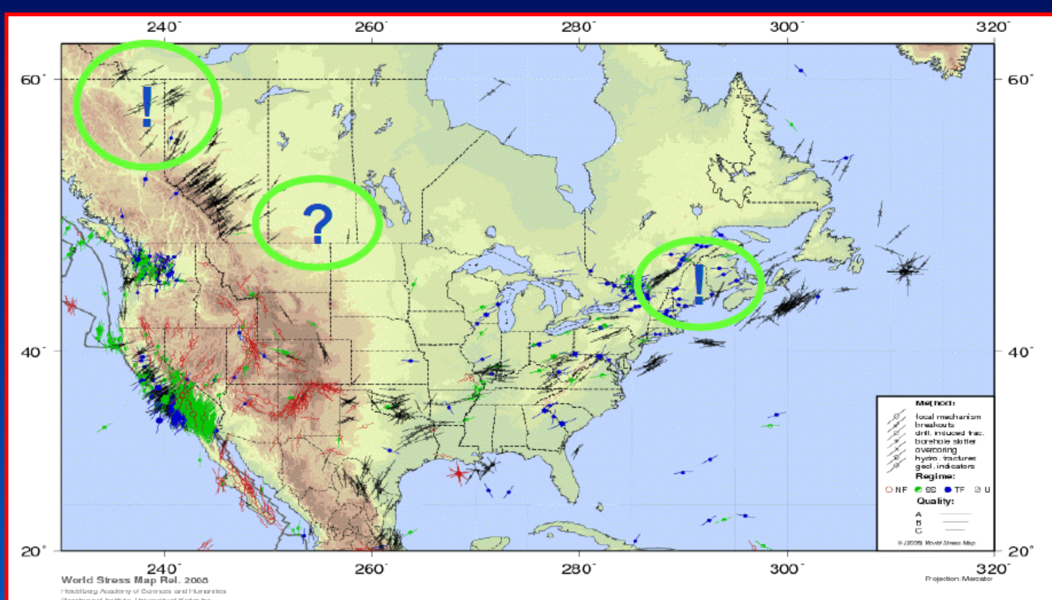
World Stress Map



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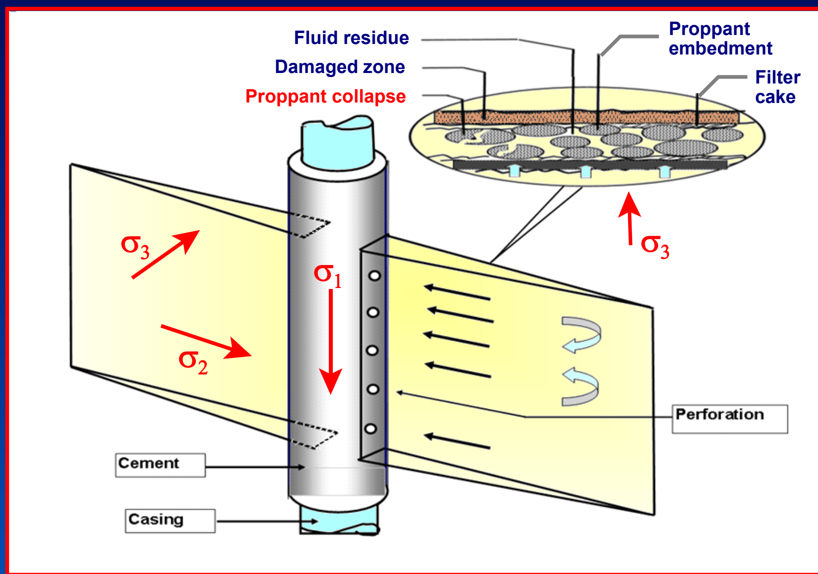
Why Minimum Stress (σ_3) is Important to Know?



Where:

- σ_1 : Overburden stress
- σ_2 : Principle (max. stress)
- σ_3 : Minimum stress (closure stress)

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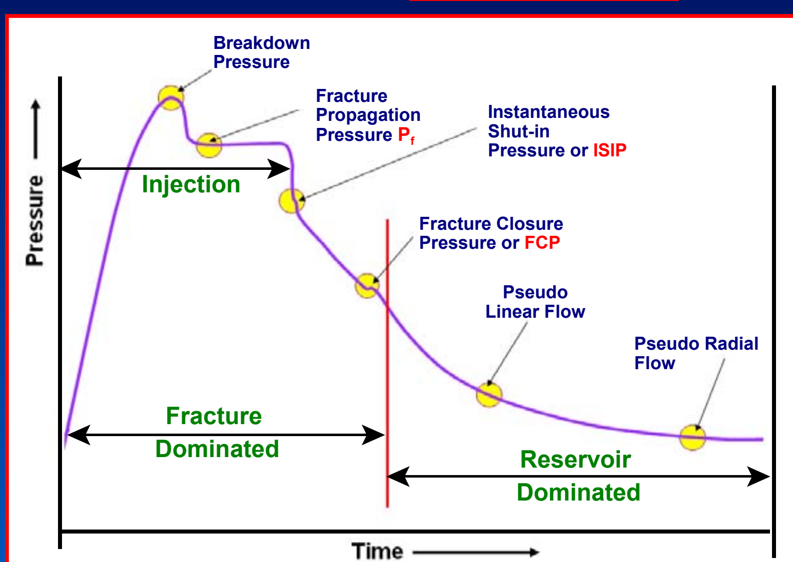
Mini Frac Typical Pressure Profile

Rule: P_f > ISIP > P_c



No flowback test

ISIP: the minimum pressure required to hold open a fracture

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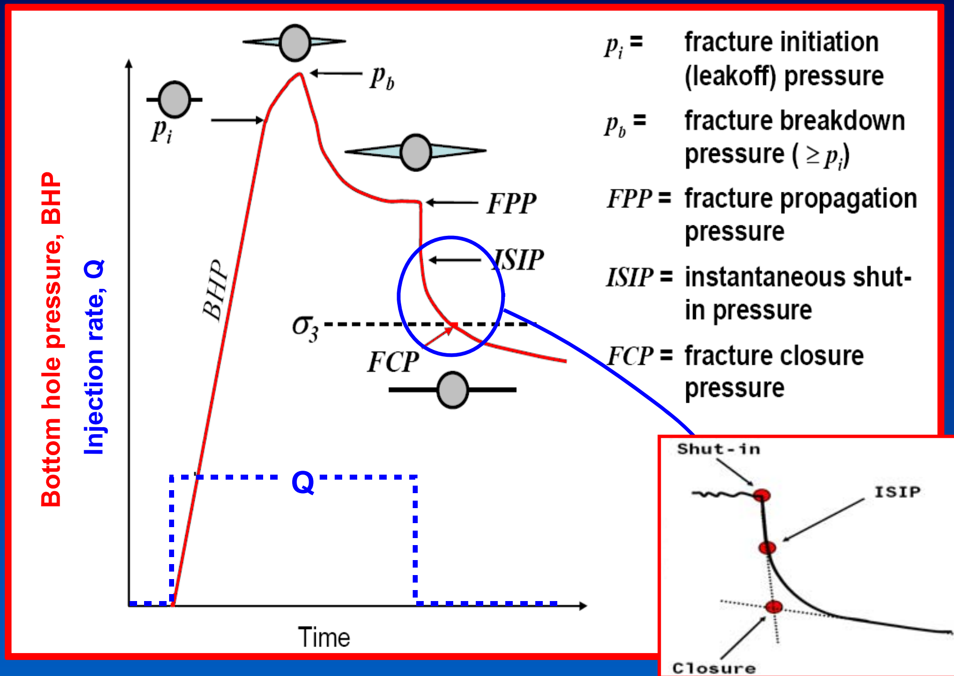
Fracture Dominated Analysis



ISIP: identified by significant Slope Change

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Determination of ISIP

$$ISIP = G_c . m_G + P_c$$

Where:

ISIP: Instantaneous shut-in pressure
P_c: Closure pressure
G_c: Value of the G-Function at closure pressure
m_G: Slope of the G-Function prior to closure pressure

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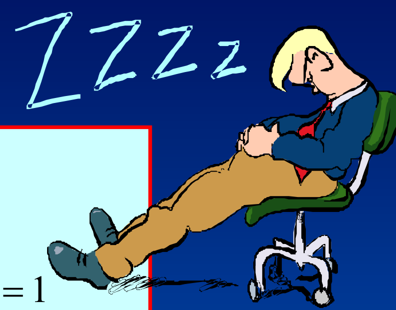
What is G-Function?

G-function is an analytical technique used to define the closure pressure and the types of leak-off



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

$$g(\Delta t_D) = \frac{4}{3}\left((1+\Delta t_D)^{1.5} - \Delta t_D{}^{1.5}\right) for\, \alpha = 1$$

$$g(\Delta t_D) = (1+\Delta t_D)\sin^{-1}\left((1+\Delta t_D)^{-0.5}\right) + \Delta t_D{}^{0.5}$$

$$for\, \alpha = 0.5$$

$$\Delta t_D = (t - t_p)/t_p$$

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

By: Kenneth G. Nolte in 1979

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Pre-Closure Analysis

The **G-Function** is used to determine the Fracture Closure Pressure (FCP), and identify the common leakoff types:

- Normal Leakoff
- Pressure dependent Leakoff
- Fracture Tip Extension Leakoff
- Fracture Height Recession Leakoff

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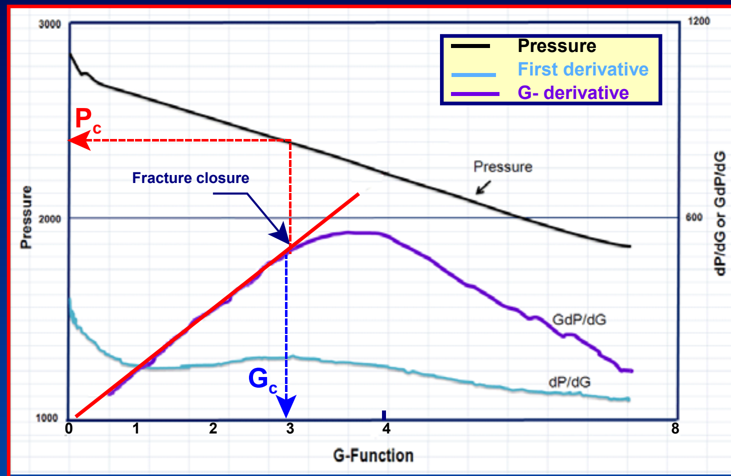
Normal Leakoff

When does it occur?

Occurs when the fracture area is constant during shut-in and the leakoff occurs through a homogeneous rock matrix



Characteristics:

- Pressure derivative **(dP/dG)** during fracture closure (**first derivative**)
- The G-Function derivative **(G dP/dG)** lies on a straight that passes through the origin (**G-Function derivative)** or semi-log derivative
- Deviation of G-Function from the straight line, determines fracture closure pressure (FCP)

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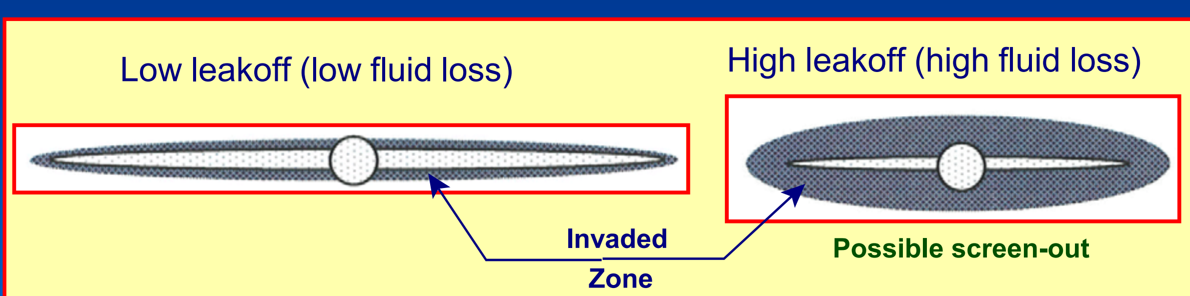
Frac (fluid) Efficiency (ή)

$$\text{Frac (fluid) Efficiency } (\acute{\eta}) = \frac{\text{Total fluids injected} - \text{Fluid Leakoff}}{\text{Total fluids injected}}$$

$$= \frac{\text{Fluids remaining in frac}}{\text{Total fluids injected}}$$

A high fluid efficiency means low leakoff and indicates the energy used to inject the fluid was efficiently utilized in creating and growing the fracture. Unfortunately, low leakoff is also an indication of low permeability.



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Frac (fluid) Efficiency (ή)

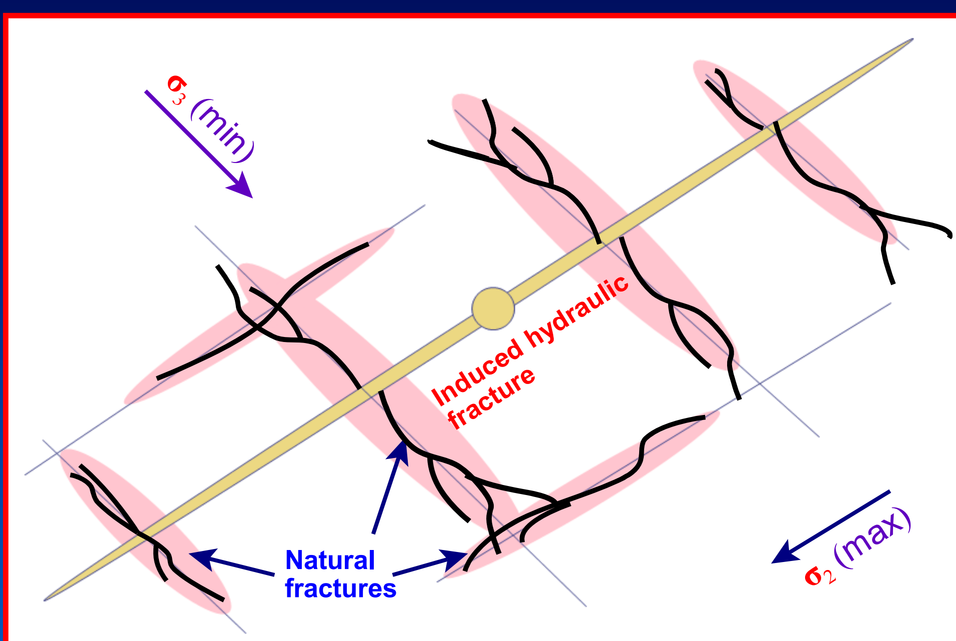
$$(ή) = \frac{G_c}{(G_c + 2)}$$ at closure pressure

- For $G_c = 3$ ή = 3/(3+2) = **60%** High leakoff or high fluid loss
- For $G_c = 30$ ή = 30/(30+2) = **94%** Low leakoff or low fluid loss

Where:

G_c: is the G-function time at fracture closure

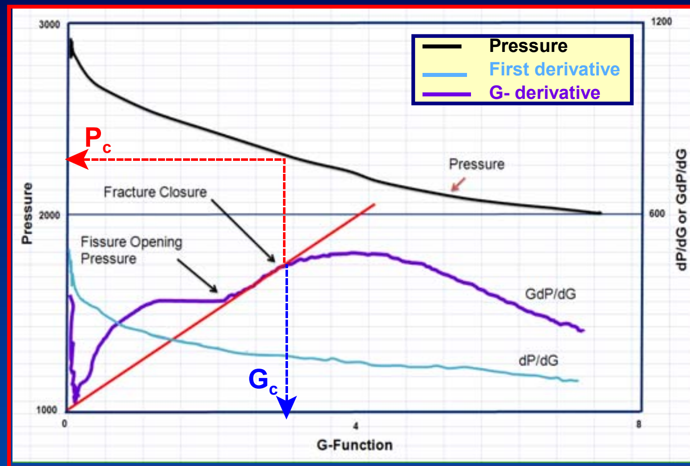
Pressure Dependent Leakoff (PDL)



Pressure Dependent Leakoff (PDL)

When does it occur?

When secondary fractures existent in the formation and intersect the main fracture



Characteristics:

- G-Function shows a large hump above the straight line
- Subsequent to the hump, G-Function shows a normal leak off (linear trend)
- The end of the hump identifies the fissure opening pressure
- Deviation of G-Function from the straight line, determines fracture closure pressure (FCP)

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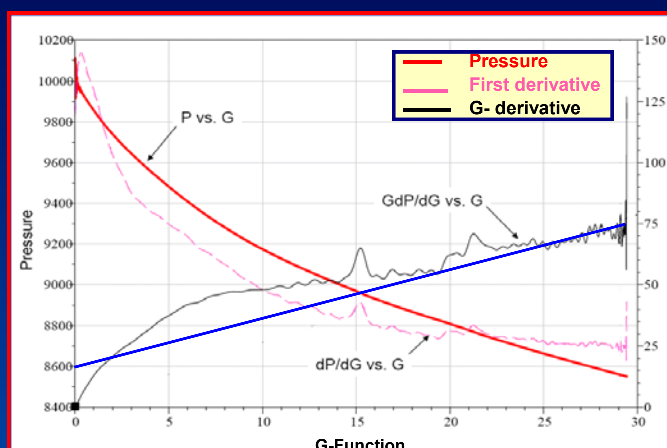
Fracture Tip Extension Leakoff

When does it occur?

Occurs when a fracture continues to grow even after injection is stopped and the well is shut-in. It is a phenomenon that occurs in very low permeability reservoirs, as the energy which normally would be released through leakoff is transferred to the ends of the fracture resulting in fracture tip extension.



Characteristics:

- The G-Function derivative G dP/dG initially exhibits a large positive slope that continues to decrease with shut-in time, yielding a concave-down curvature.
- Any straight line fit through the G-Function derivative G dP/dG intersects the y-axis **above the origin**.

As long as the G-Function keeps increasing, fracture closure has **NOT** occurred yet

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Mini Frac Followed by a Flowback Period

Why a flowback after mini frac is needed?

- For a “fracture tip extension” leak-off, fracture closure is not observed.
- Therefore, a closure pressure can’t be estimated
- An excessively long fall-off period is required to observe fracture closure
- Flowing back the well after the fall-off period, will induce fracture closure; and hence, allow an estimate of the closure pressure (P_c).

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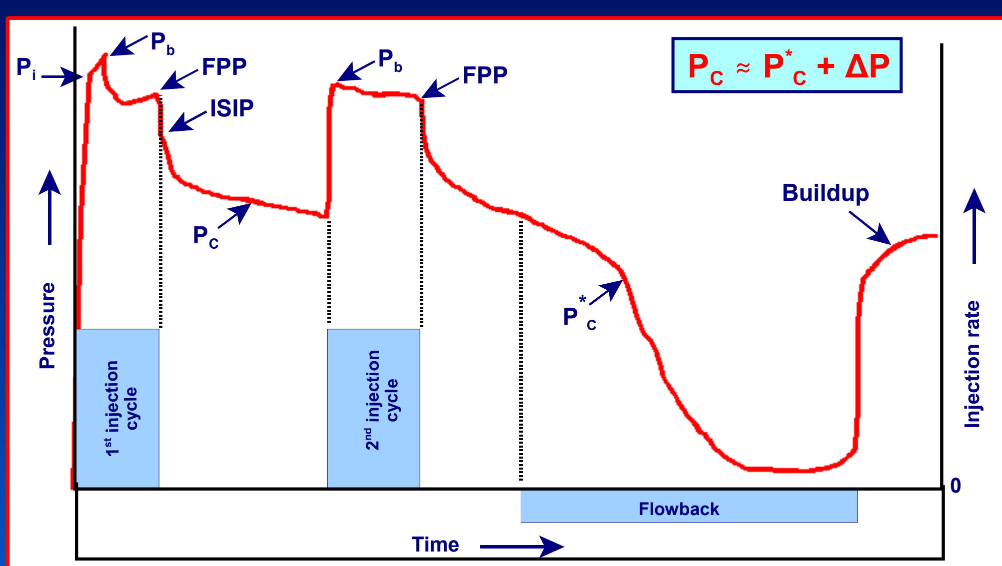
Mini Frac Typical Pressure Profile (with flowback)



P_i Fracture initiation pressure (leak-off)
P_b Fracture break-down pressure
FPP Fracture propagation pressure

P_C Closure pressure during fall-off
P^*_C Closure pressure during flow
ΔP Draw-down pressure during flowback

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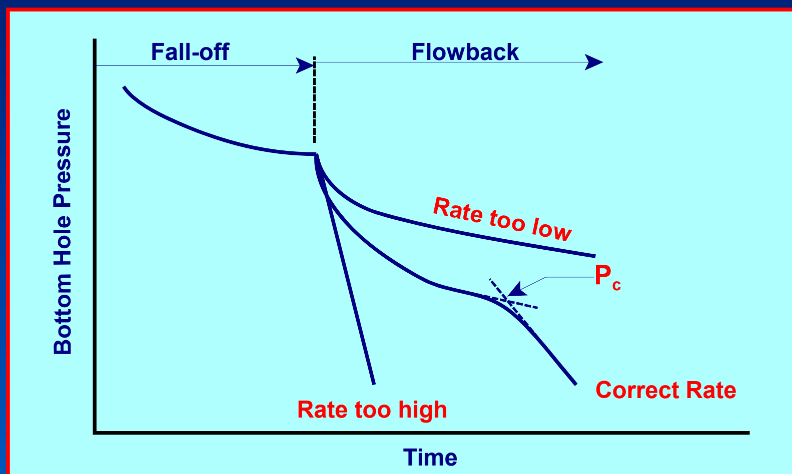
Considerations for the Flowback

In order to clearly observe the closure pressure, it is recommended to select the flowback rate at approximately 1/6 to 1/4 of the last injection rate.



Ref: Nolte K.G "Fracture Evaluation Using Pressure Diagnoses"

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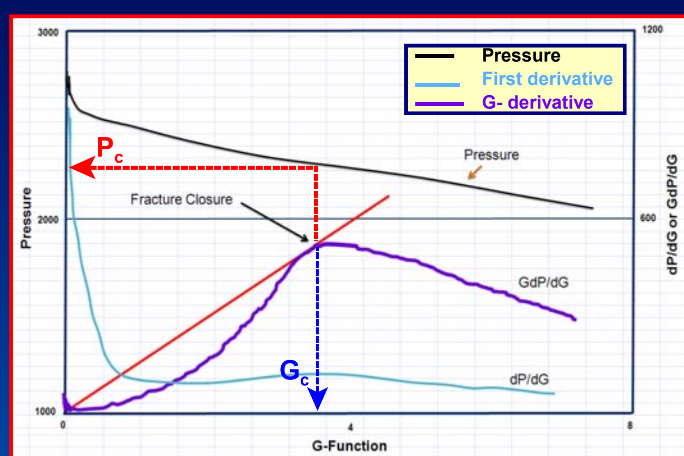
Fracture Height Recession Leakoff

When does it occur?

Occurs if the fracture propagates through adjoining impermeable layers during injection



Characteristics:

- The G-Function derivative G dP/dG lies below the straight line extrapolated through the normal leakoff data.
- Both G-Function and the first derivative exhibits a concave up trend

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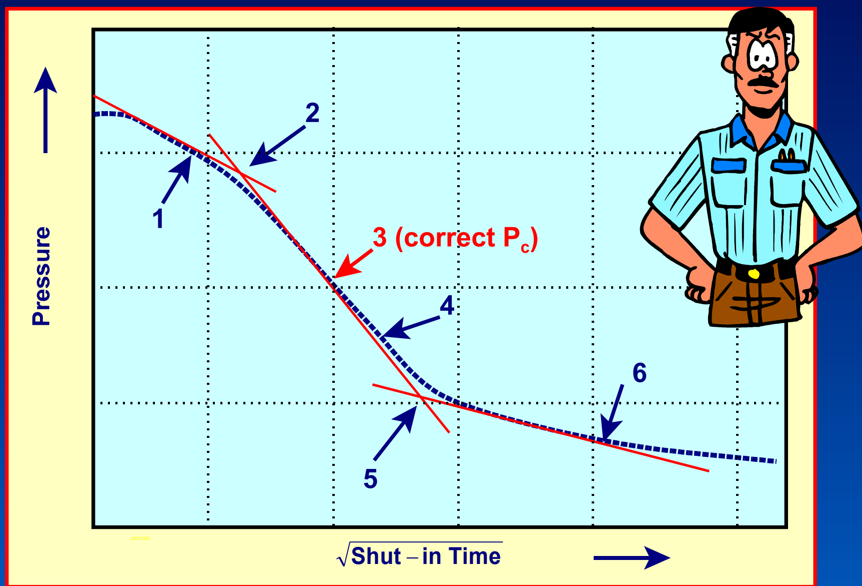
Use of Square Root of Time ($\sqrt{t}$) to Pick the Closure Pressure (P_c) ??



2007 SPE Hydraulic Fracturing Conference in College Station, Texas,.
by: Ken Nolte

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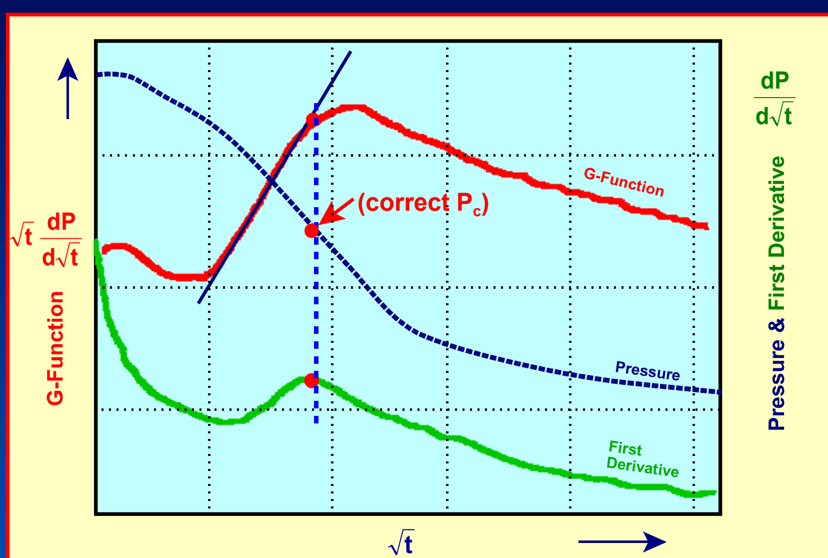
Use of Square-root of Shut-inTime Plot to Confirm Closure Pressure (P_c)



First derivative $\frac{dP}{d\sqrt{t}}$ vs. $\sqrt{t}$

G-Function or Semi-log derivative $\sqrt{t}\,\frac{dP}{d\sqrt{t}}$ vs. $\sqrt{t}$

Closure pressure is recognized by a “local” high on the First Derivative plot

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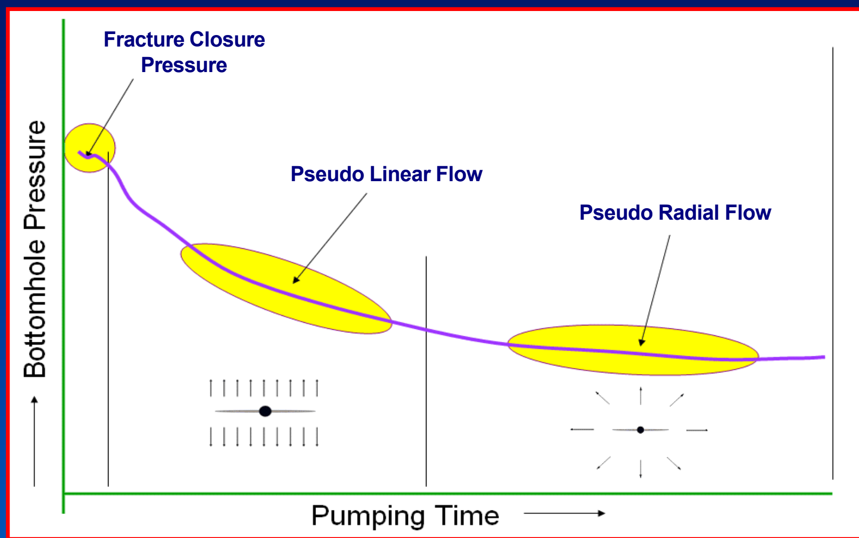
After Closure Analysis (ACA)

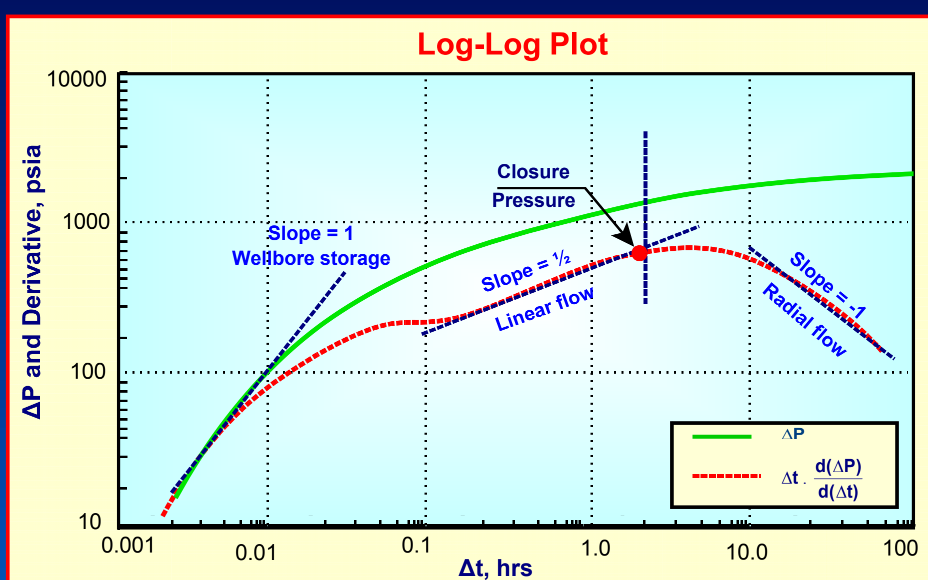
Reservoir Dominated Analysis:



After-Closure Analysis, from Talley et al (SPE 52220)

Log-Log Diagnostic Plot

(Normal Leak-off)



Closure pressure; determined from the G-function and $\sqrt{\Delta t}$ plots, occurs also when the derivative plot deviates from the ½ unit slope straight line on this Diagnostic plot

Flow Regime Diagnoses After Closure

Use of the pressure diagnostic Log-Log plot

	Slope	Flow Pattern	Description
Before Closure	¼	Bilinear	Fluid flows from the fracture along linear flow paths normal to the fracture and along the fracture.
	½	Fracture linear	Fluid flows along the fracture thus increasing fracture width.
After Closure	-¾	Bilinear	Fluid flows from the fracture along linear flow paths normal to the fracture and along the fracture. (In reality, closure is unlikely to be truly instantaneous.)
	-½	Formation linear	Fluid flows into the formation in paths normal to the fracture plane.
	-1	Pseudo-radial	Fluid flows radially into the formation from the wellbore.

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Definition of Pressure Derivative Plots (DFIT Analysis)

For very short injection/production period relative to the fall-off/buildup period:

Use "injection/drawdown" derivative:

The derivative plot is the slope in a plot of **pressure** versus **log Δt**, from the semi-log plot

For reasonable injection/production period relative to the fall-off/buildup period:

Use "fall-off/buildup" derivative:

The derivative plot is the slope in a plot of **pressure** versus **log $(t_p + \Delta t)/\Delta t$**, from the semi-log plot

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Method of Determining Fracture Closure Pressure (FCP)

1. G-Function Plot
2. Square Root Plot
3. Log-log Diagnostic Plot

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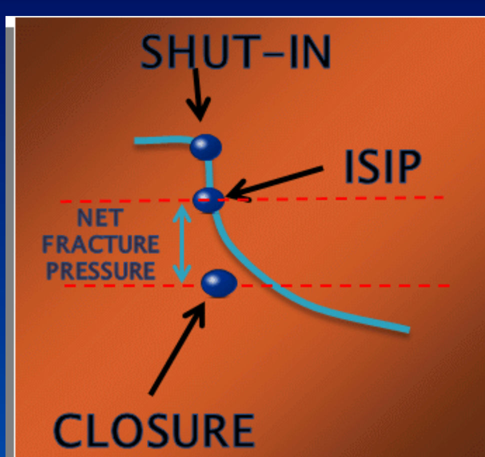
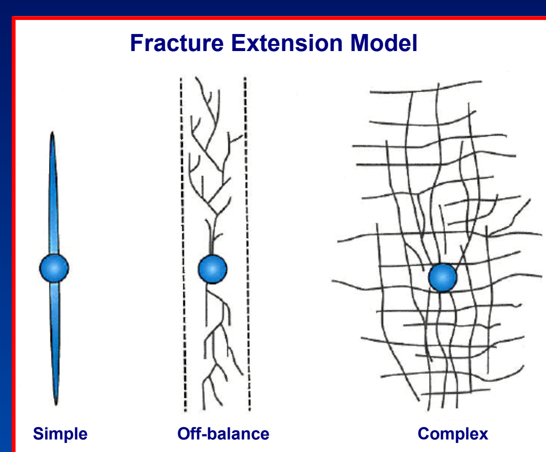
Net Fracture Pressure (NFP) vs. Fracture Network Complexity





The more complex the formation, the more natural fractures may exist and the higher is the Net Fracture Pressure

Ref: Dan Potocki, SPE 162814

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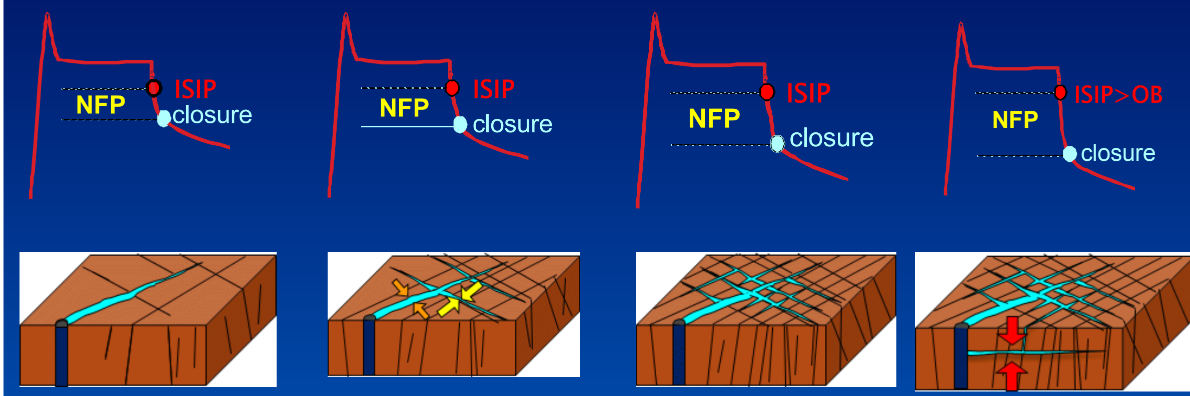
Net Fracture Pressure (NFP) vs. Fracture Network Complexity



More Induced Fracture Complexity

Increasing NFP →

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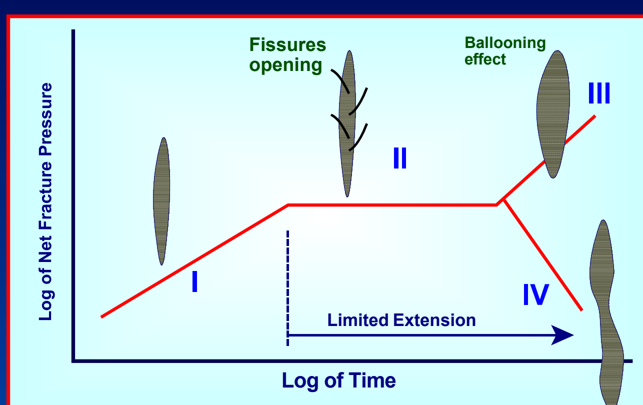
Schematic of Net Fracture Pressure (NFP)

Indicating Progress of Fracture Extension



I - Confined height; unrestricted Extension

II - Constant NFP plateau can result in unstable growth, fluid loss or fissures opening

III - Fracture growth ceases...continued injection increases width of the fracture; balloon effect. This is the desired behaviour if a tip screenout treatment has been designed

IV - Unstable height. During fracturing, if a barrier is crossed and encountered a lower stress zone ($P_f > \sigma_{zone}$) an accelerated height growth will occur, which is undesirable - should terminate injection

Source: Nolte, K.G. and Smith, M.G. 1981. Interpretation of Fracturing Pressures. J Pet Technol 33

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After Closure Analysis (ACA)

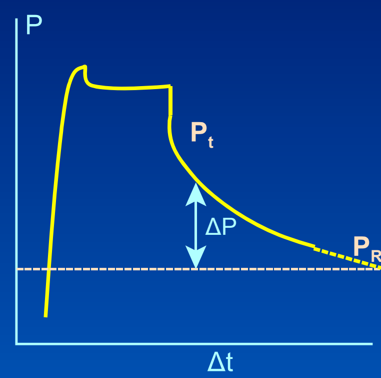
Procedures:

1. Flow regime diagnostic Plot:

a. Confirm flow regimes (radial, linear)
b. **Estimate** reservoir pressure, P_R

2. Radial flow analysis

a. **Confirm** reservoir pressure, P_R
b. Estimate formation permeability, k



After Closure Analysis (ACA)

1. Flow regime diagnostic Plot:

Fall-off data is plotted on a Log-log of dP vs the square of the time function "F_L":

- ΔP: $(P_t - P_R)$
- Time function (F_L)

$$\boxed{F_L = \frac{2}{\pi} . \sin^{-1} \sqrt{\frac{t_c}{t}}}$$

Valid only for $t \geq t_c$

Where:

- F_L : dimensionless time function
- P_t : Pressure at shut-in "t"
- P_R : Static/stabilized reservoir pressure
- T_c : Time at fracture closure pressure

Flow Regime Diagnoses

Procedure:

- The analysis depends on an accurate closure pressure pick; to use after closure data ($t > t_c$)
- The pressure difference (ΔP) or (P_t - P_R) curve is completely dependent on the value of reservoir pore pressure used (estimated)
- The pressure derivative is insensitive to the reservoir pressure estimate
- For this reason the method is iterative and the pressure derivative should be used for all initial analyses.

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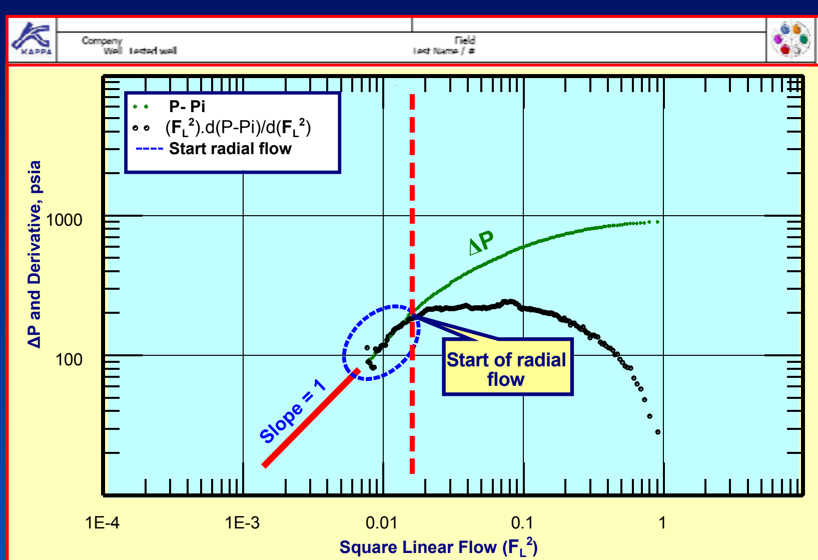
After Closure Analysis (ACA)

Identification of Radial Flow Regime



Radial flow is confirmed when both dP and pressure derivative curves overlap, forming a straight line with a unit slope

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After Closure Analysis (ACA)

2. Radial flow analysis:

Fall-off data is plotted against the time function "F_R":

- Fall-off pressure data vs.
- Time function (F_R)

$$\boxed{F_R = \frac{1}{4} . \ln\left(1 + \frac{x . t_c}{1 - t_c}\right)}$$

Where:

$$x = \frac{16}{\pi^2} \cong 1.6$$

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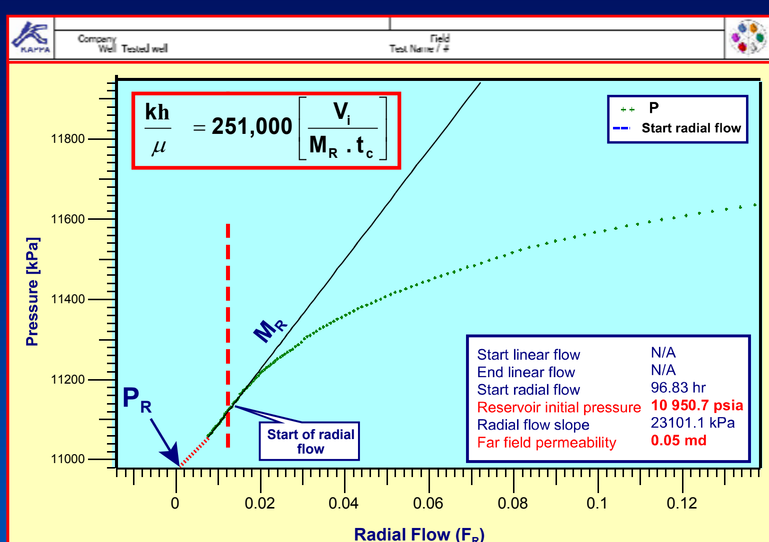
After Closure Analysis (ACA)
Radial Flow Analysis



- Extrapolation of the straight line of the radial flow regime, yields the reservoir pressure **(P_R)**
- The slope of the line (M_R), yields the flow transmissibility **(kh/μ)**

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Permeability Est. from G-Function

This empirical formula gives an estimate of the permeability when after-closure **radial flow** data are not available

$$k = \frac{0.0086\,\mu_f \sqrt{0.01\,(P_{ISIP} - P_c)}}{\phi\; c_t\,(G_c \,.\, E \,.\, r_P / 0.038)^{1.96}}$$

Where:

K:	Formation permeability	md
μ_f:	Fluid viscosity	cp
P_{ISIP}:	Instantaneous shut-in pressure	psi
P_c:	Closure pressure	psi
ϕ:	Porosity	frac
c_t:	Total compressibility	psi^{-1}
G_c:	G-function at closure pressure	
E:	Young's Modulus	MMpsi
r_P:	Leakoff height to gross frac height ratio	

Mini Frac Design

Important tips:

- It is important to obtain a rough estimate of the frac pressure prior to test from:
  - The Eaton's formula, or
  - Knowledge from offset wells
- It is recommended to run BHP recorders instead of measuring WHP's to avoid:
  - Inaccuracies in converting WHP data to BHP
  - In case the WHP goes on vacuum
  - Insulate wellhead, if high ambient temperature fluctuation is expected
- Fill up wellbore with water before starting injection to reduce WBS duration and avoid pressure spikes (wtr. hammering)
- Add 3% KCl to injection water to reduce potential formation damage

Mini Frac Design (cont.)

Test duration:

- The lower the injection pressure, the shorter the fall-off period to reach radial flow
- The shorter the injection period, the shorter the fall-off period

Injection period	Permeability (md)	Time to Closure Pressure
5 min	0.1	0.2 hr (12 min)
20 min	0.1	1.0 hr
5 min	0.01	2-3 hrs
5 min	0.0001	10 days

- Time to radial flow regime is approx. 3 time it takes to reach closure pressure

Source: JPT September 2014

How to Estimate the Fracture Pressure

Eaton's Formula

Estimate of Fracture Pressure/Gradient

Field :	South Pierson	Zone :	Spearfish
Well :	Typical Well	Lithology:	Dol/SS

$$P\ (frac) = NOB \left(\frac{u}{1-u} \right) + P\ (PV) \quad \text{Psi/ft}$$

Where :

P (frac) :	Fracture Pressure Gradient			0.475	Psi/ft
NOB :	Net Overburden Pressure Gradient			0.858	Psi/ft
	(Overburden Grad.- Pore Pressure Grad.)				
u :	Poisson's Ratio "u" =	0.27	Limestone	0.28	
		0.33	Sandstone		
P (PV) :	Pore Pressure Gradient			0.142	Psi/ft
P	Current 'Reservoir Pressure			479	Psi
D :	Depth			3378	ft

Summary Results:

Fracture Pressure Gradient	0.475	Psi/ft
Fracture (Parting) Pressure	1606	Psi
	11075	KPa

Note:

Overburden gradient is 1.0 Psi/ft

Impact of Ambient Temperature on DFIT

Ambient temperature change between day & night over 50 °F (10 °C), can yield cyclic measured pressure data measured at the surface which makes DFIT analysis difficult, and results will be unreliable. This can happen under 3 different scenario's:

- Thermal compensation of pressure recorder
- Thermal expansion/contraction of the fluids in the wellbore
- The use of capillary tubing to connect the pressure recorder to the wellhead is questionable....

Source: JPT September 2014

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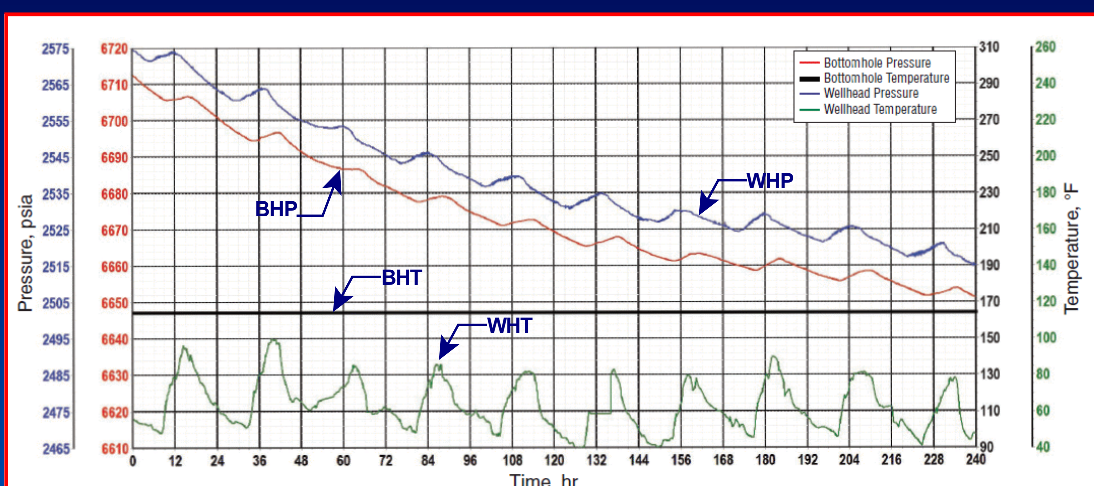
Pressure and Temperature Profiles



- The cyclic change in the ambient temperature, has affected both wellhead and bottom hole pressure data for uninsulated wellhead.
- No affect on bottom hole temperature

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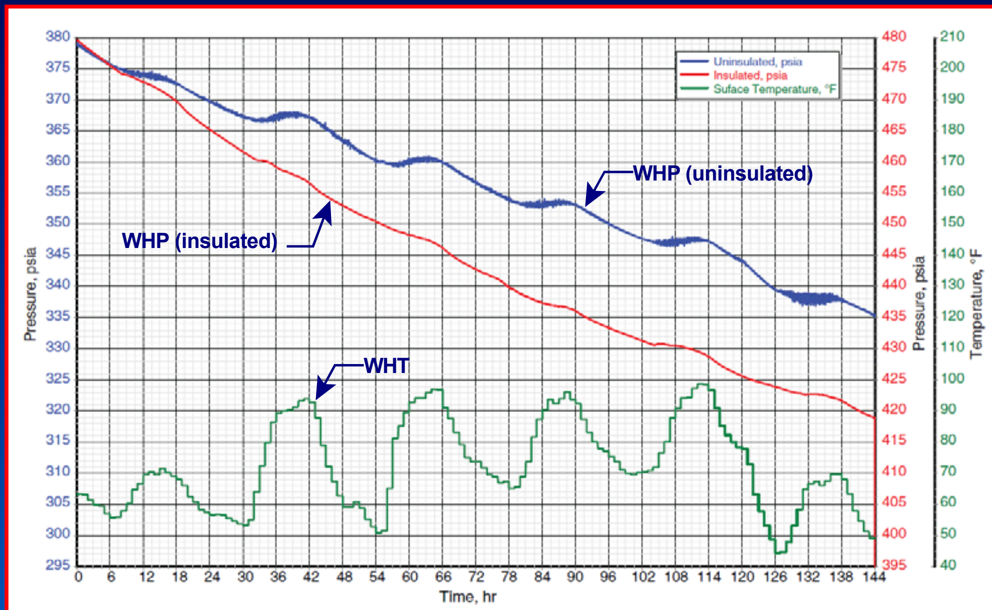
Benefits of Wellhead Insulation



The wellhead pressure curves in a well with insulation and without insulation are shown with the fluctuation in surface temperature

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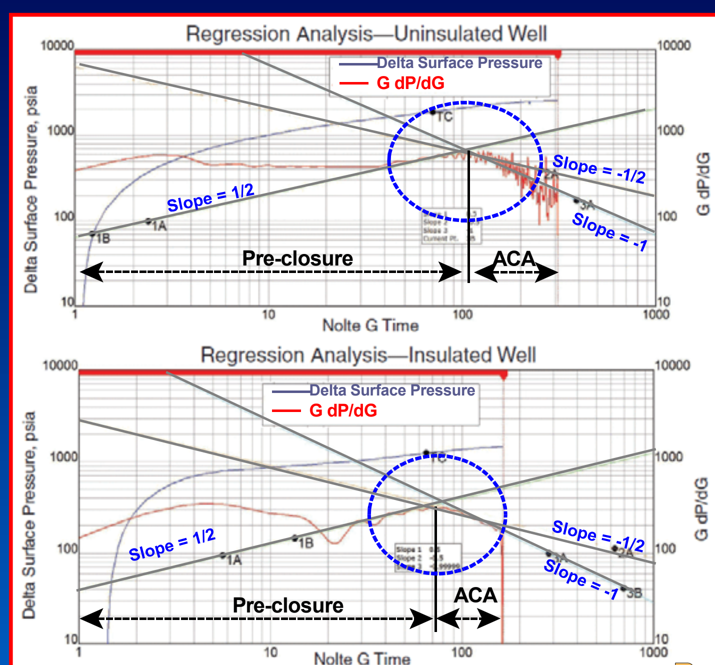
Benefits of Insulating Wellhead

Benefits:

- Smooth data during radial flow
- Easy to recognize closure pressure

Recommendations:

- Insulate wellhead
- Use fluids with low thermal expansion to reduce cyclic pressures caused by changes in ambient temperature



ACA: After closure analysis

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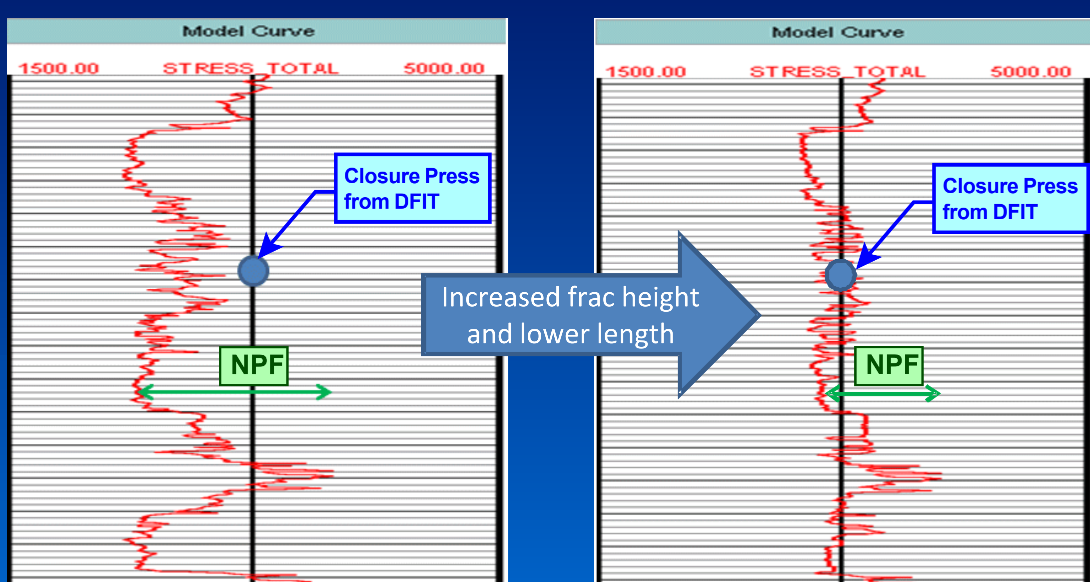
Info from DFIT Used for Frac Model Input

- Basic reservoir parameters; perm and pressure
- Geological data; such as the presence of natural fractures and geological complexity (NFP)
- Leakoff type and coefficient (rate of fluid loss to the formation)
- Frac efficiency
- Calibration of local stress profile obtained from open hole logs

Calibration of Local stress

Frac models utilize rock mechanic parameters; Poisson's ratio and Young's Modulus, to generate local stress profile. Closure pressure from DFIT can be used to calibrate the generated stress profile

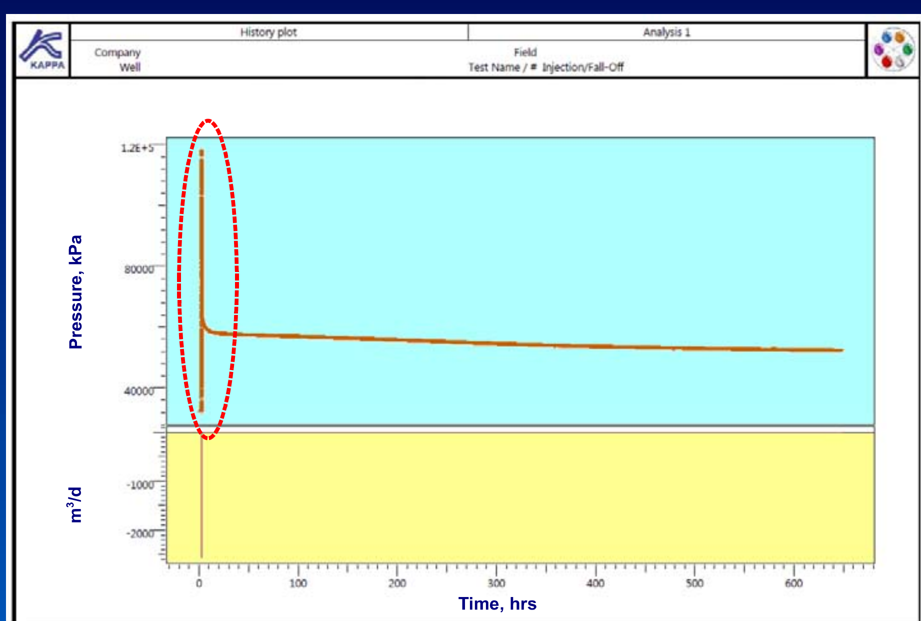


Case Study

Mini Frac
Duvernay Formation

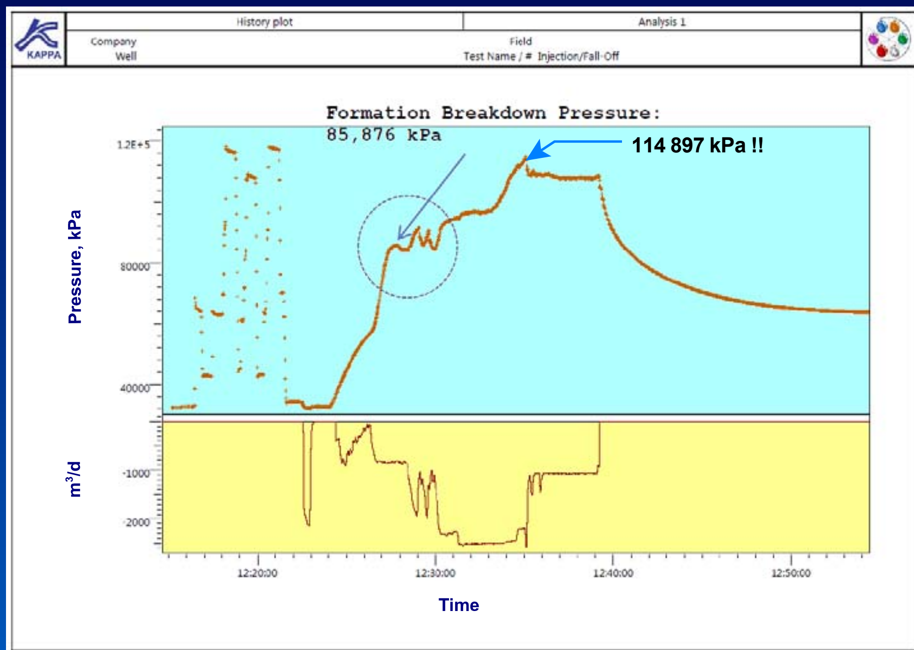
Duvernay Ex

Test Raw Data



Real time pressure measurement was used. Final fall-off period extended to 650 hrs (27 days)

Injection Period



Injection pressures are too high, reaching114.9 mPa, and injection period a little long; 25 minutes

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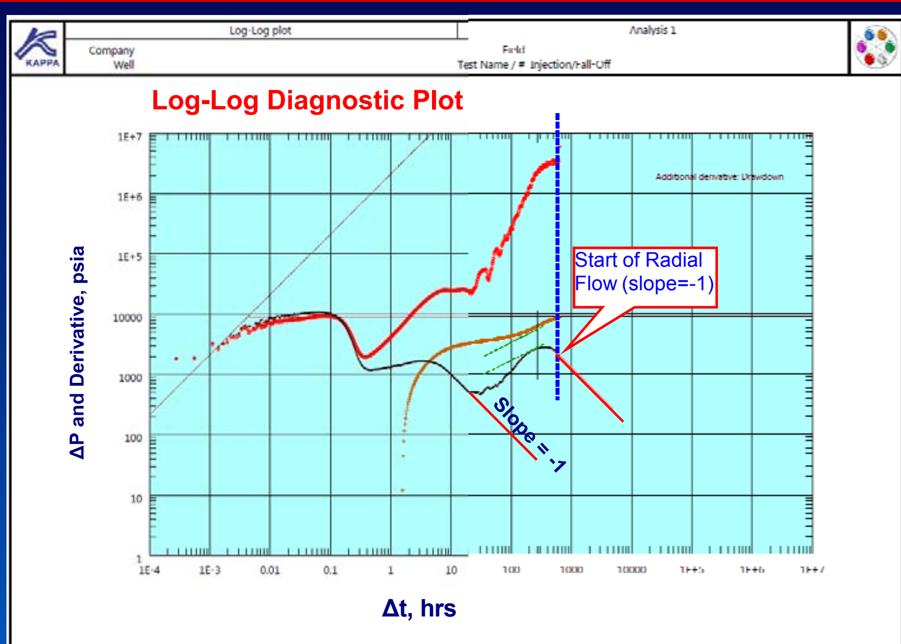
Diagnoses of Flow Regimes



- Pressure derivative plot showed a straight line with a slope of -1 after only 20 hrs of shutin. **Has radial flow really been reached??**
- Departure of derivative from ½ slope, confirms closure pressure

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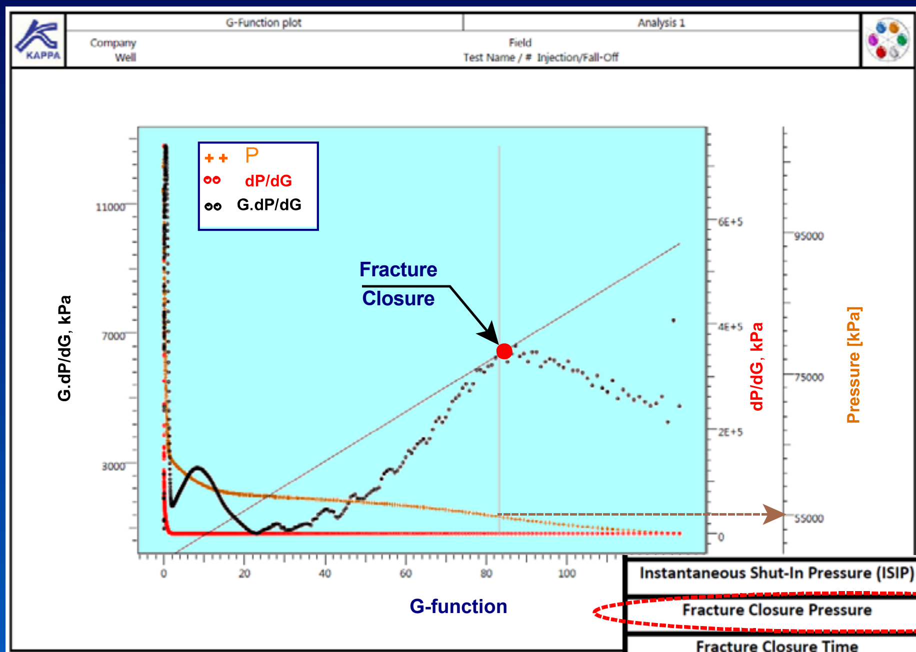
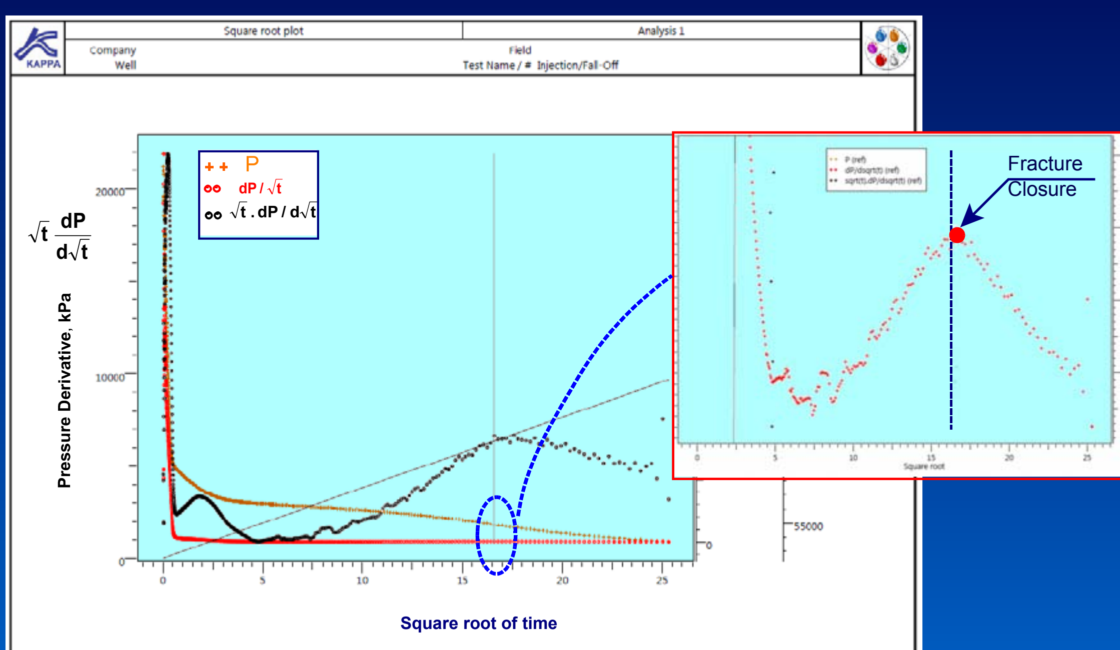
G-Function Plot



Instantaneous Shut-In Pressure (ISIP)	61,114.4	kPa
Fracture Closure Pressure	54,768.8	kPa
Fracture Closure Time	231.831	hr
Initial Reservoir Pressure	50,807.5	kPa
Closure G-value	83.1803	-

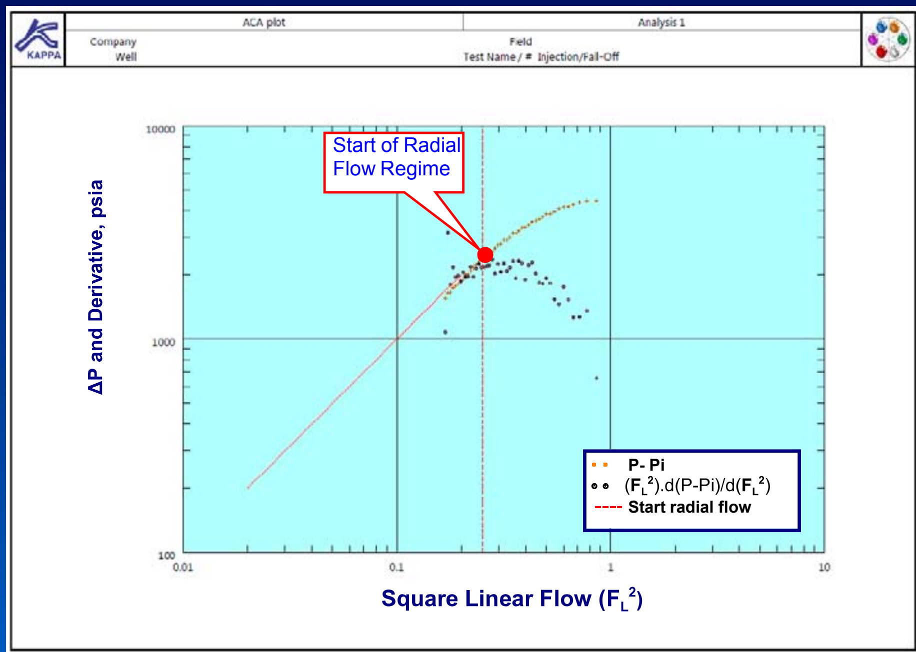
Frac height recession leakoff;
very high injection pressure was used

Identification of Closure Pressure
(Square Root Plot)



Closure pressure is confirmed by a “local” high of the square root plot

Identification of Radial Flow



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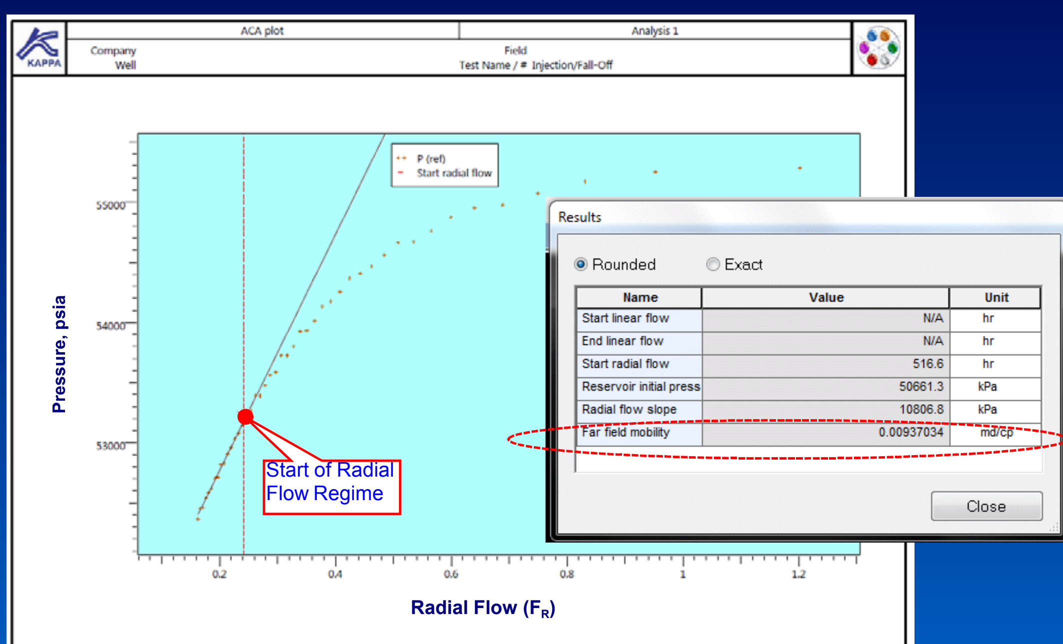
Radial Flow Analysis (ACA)



Name	Value	Unit
Start linear flow	N/A	hr
End linear flow	N/A	hr
Start radial flow	516.6	hr
Reservoir initial press	50661.3	kPa
Radial flow slope	10806.8	kPa
Far field mobility	0.00937034	md/cp

Mobility (k/u) = 0.00937

K = 0.00937 x 0.033 = 0.0003 md

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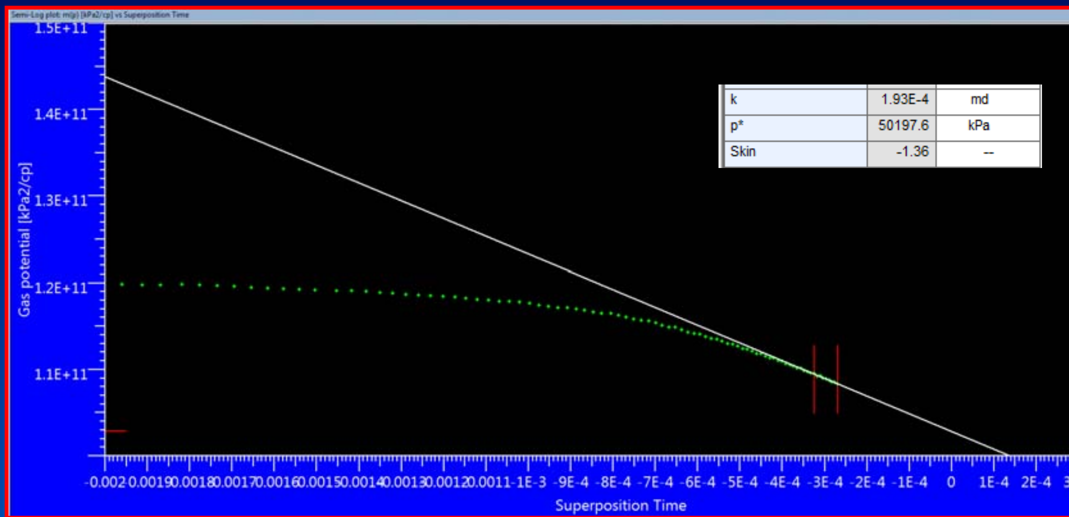
Horner Plot



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Summary of Results

Parameter	ACA (radial)	Derivative	Horner	G-function
Permeability, md	0.0003	0.0002	0.0002	n/a
Pressure, kPa	50,661	n/a	50,197	n/a
Skin	n/a	n/a	-1.4	
Closure pressure, kPa	n/a	n/a	n/a	54,769

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Control of Well Flow-back

Design criteria:

- Proppant strength (σ_{prop}), type, and concentration are selected to ensure it can withstand the local stresses in the rock (P_c); otherwise it could get crushed and the fracture becomes in-effective
- Increased draw-down, during the cleaning period (flow-back), can result in poor frac characteristics

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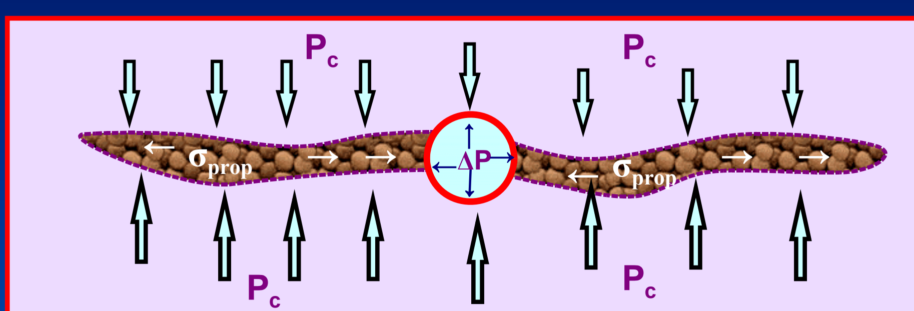
Effect of Pressure Draw-down on Proppant Design

Proppants keep the frac aperture wide open:



$$\boxed{\sigma_{prop} >> P_c + \Delta P_{drawdown}}$$

Where:

- σ_{prop} : Proppant mechanical strength
- P_c: Closure pressure
- $\Delta p_{drawdown}$: Draw-down pressure

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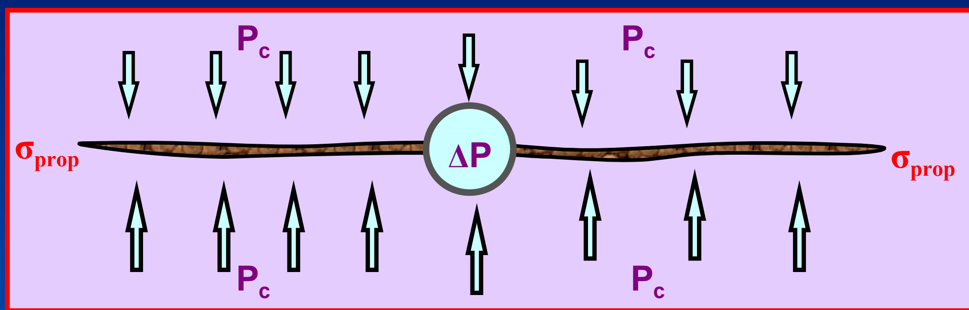
Effect of Pressure Draw-down on Proppant Design

Proppants are crushed; frac is closing:



$$\sigma_{prop} << P_c + \Delta P_{drawdown}$$

If P_c is relatively high, draw-down pressure should be controlled to avoid crushing the proppants/frac closure

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Case Study

Impact of Well Flowback on Performance (Haynesville Shale Gas)

SPE: 144425

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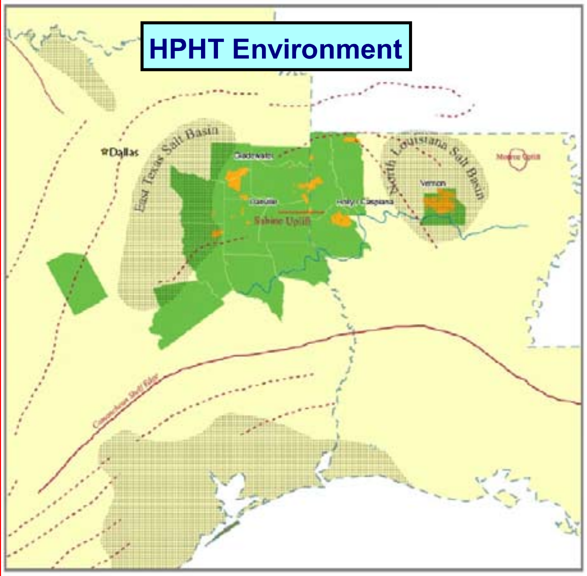
Background



Basin Summary

- 50,000 square miles
- Over 6 Bcfe/d of production
- Over 1,000 operators
- 95-100% of NYMEX gas price

East Texas / North Louisiana Overview

- Part of the Cotton Valley Sand trend, which covers parts of the East Texas Basin and Northern Louisiana Salt Basin
- Long-life reserves in a concentrated geographical area
- High drilling success rates (99+%)
- Relatively high initial production rates
- Drilling depths of 7,800 to 15,500 ft
  - Typically 10,000 ft in all areas except Vernon, where depths average over 14,000 ft

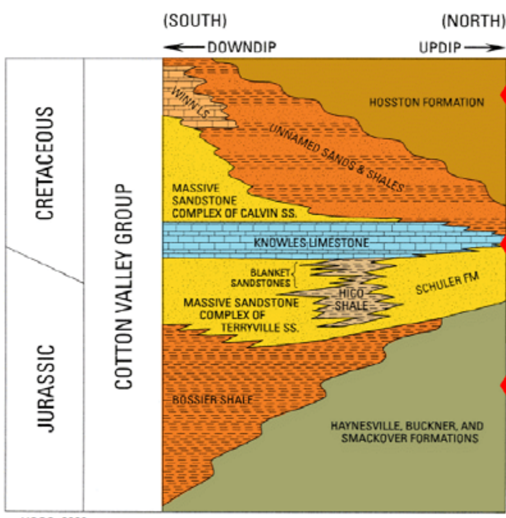
Emerging Industry Trends

- Cotton Valley 20 acre down spacing
- Horizontal Drilling in Cotton Valley, Pettet, James Lime and Travis Peak
- Deeper potential
  - Bossier / Haynesville drilling
- Completions in multiple formations utilizing new multi-frac completion hardware (for vertical and horizontal wells).

EXCO Resources, Inc.

- T = 300 to 350 °F
- Pressure > 10,000 psi (pore pressure gradient) ≈ 0.95 psi/ft

Stratigraphy



USGS, 2003

Discrete sandstones separated by thicker mudstones, represents near-shore, delta-front, and barrier bar depositional environments.

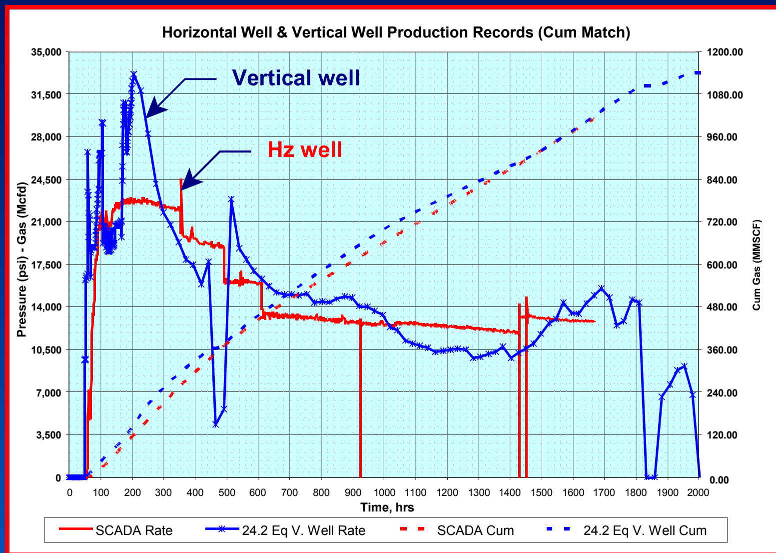
Shallow water deposits, terrigenous clastic sediments, massive shore-face sandstones reworked into marine bars, with fine-grained mudstones and lagoonal limestones.

Shallow water deposits in the north inter-fingering with deeper marine mudstones and shales. Shallow-water oolitic limestones, minor reef development on the west, more non-marine sediment sources near the TX/LA state line.

EXCO Resources, Inc.

Performance Comparison

Vertical Well vs. 1st Hz Well



- Hz well perforation: four (4), two-foot clusters, 6 SPF, 60 degree phasing
- Disappointing results of first Hz well, relative to vertical wells

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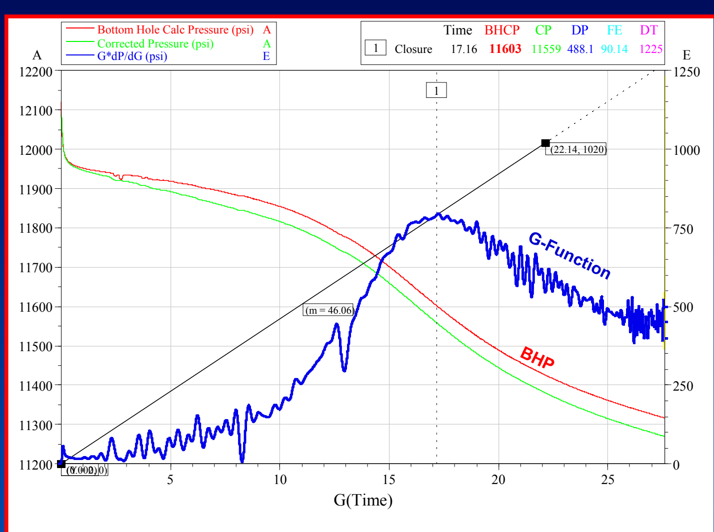
Critical Draw-down Pressure



Graph	Reservoir Pressure (psi)	Closure Pressure (psi)	Bottom Hole ISIP (psi)	Delta Pressure (psi)
Minifrac - Horner	11108		12091	
Minifrac - Square Root		11565		526
Minifrac - Log Log		11594		497
Minifrac - G Function		11603		488

Highest P_c = 11,603 psi

Critical draw-down pressure = Closure pressure - Reservoir pressure
= 11,603 - 11,108 = **488 psi**

Fracture could close if, during the flow-back, the well critical draw-down is exceeded

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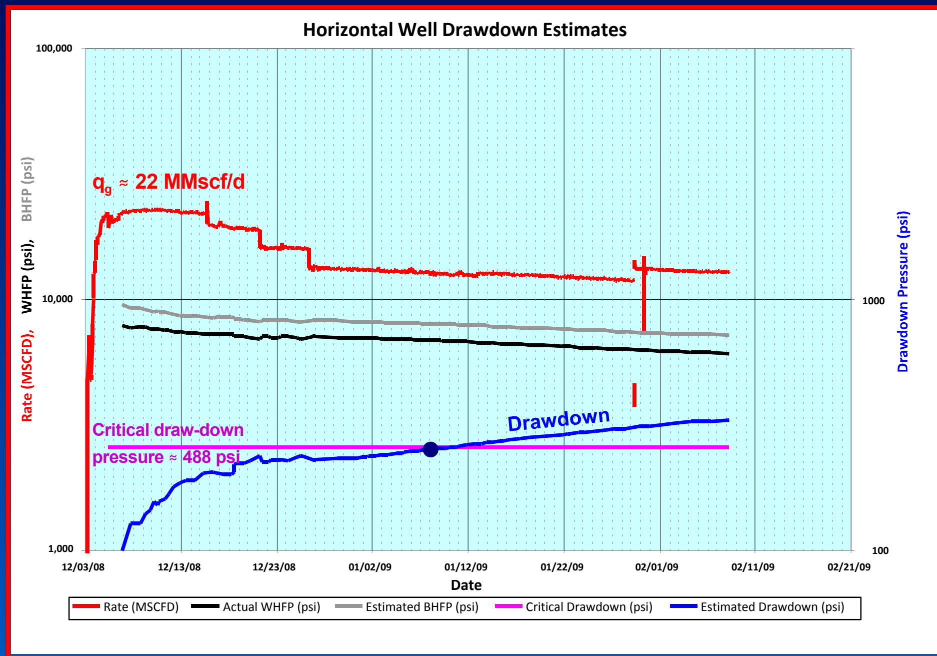
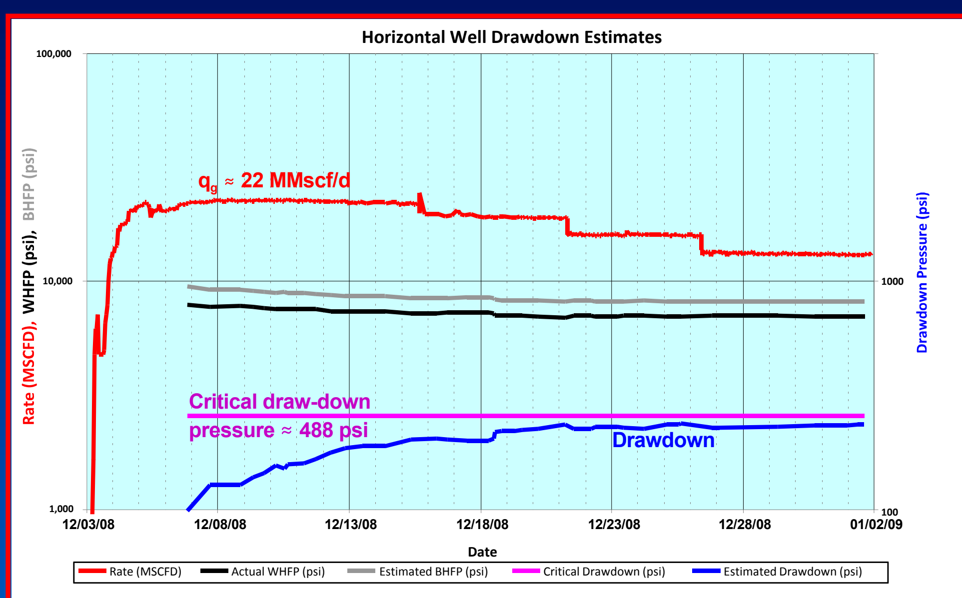
Draw-down Exceeded Critical Limit



Initial gas rate of 22 MMscf/d was maintained only for **one week**

Draw-down Below Critical Limit (one month of flow-back)



Gas rate out-performed previous case for **over a month**

Closing Comments

Why Mini frac??

- Mini Frac can yield important information; k, P, presence of natural fractures, and leakoff information
- Results from Mini Frac can be used to fine tune the frac design for vertical and Hz wells
- The closure pressure is used to estimate the critical draw-down during a well flowback to avoid poor frac performance

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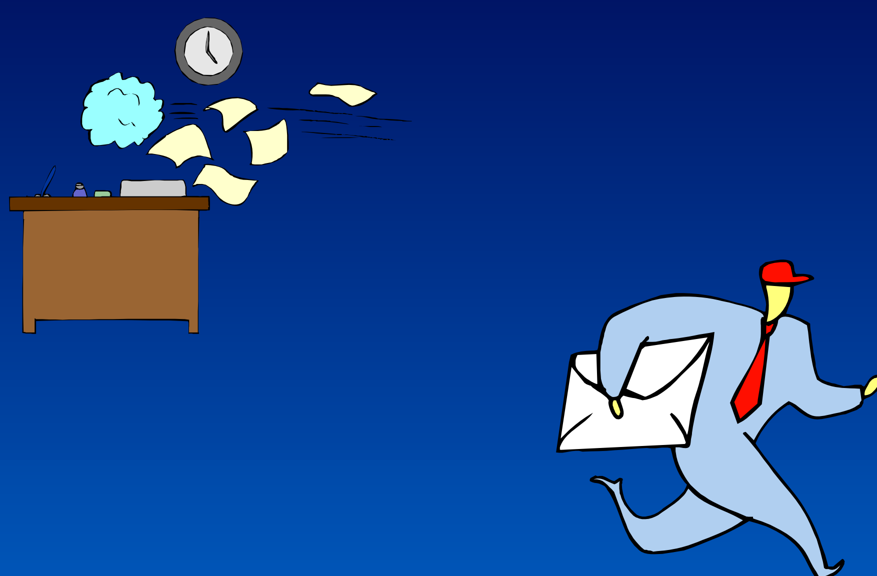
Thank You



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