PMG PETRO MANAGEMENT GROUP LTD.

Overview of Well Injection Tests

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PETRO MANAGEMENT GROUP 21st 1994 - 2015

For information:
www.petromgt.com
2016

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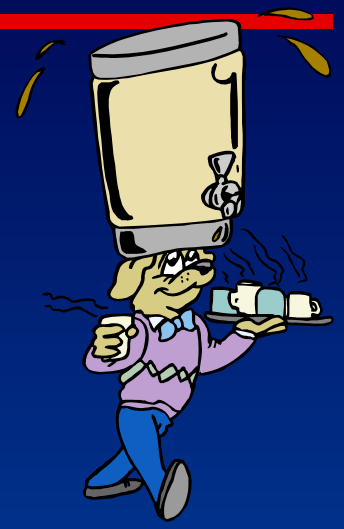
Quality Petroleum Engineering Consultants



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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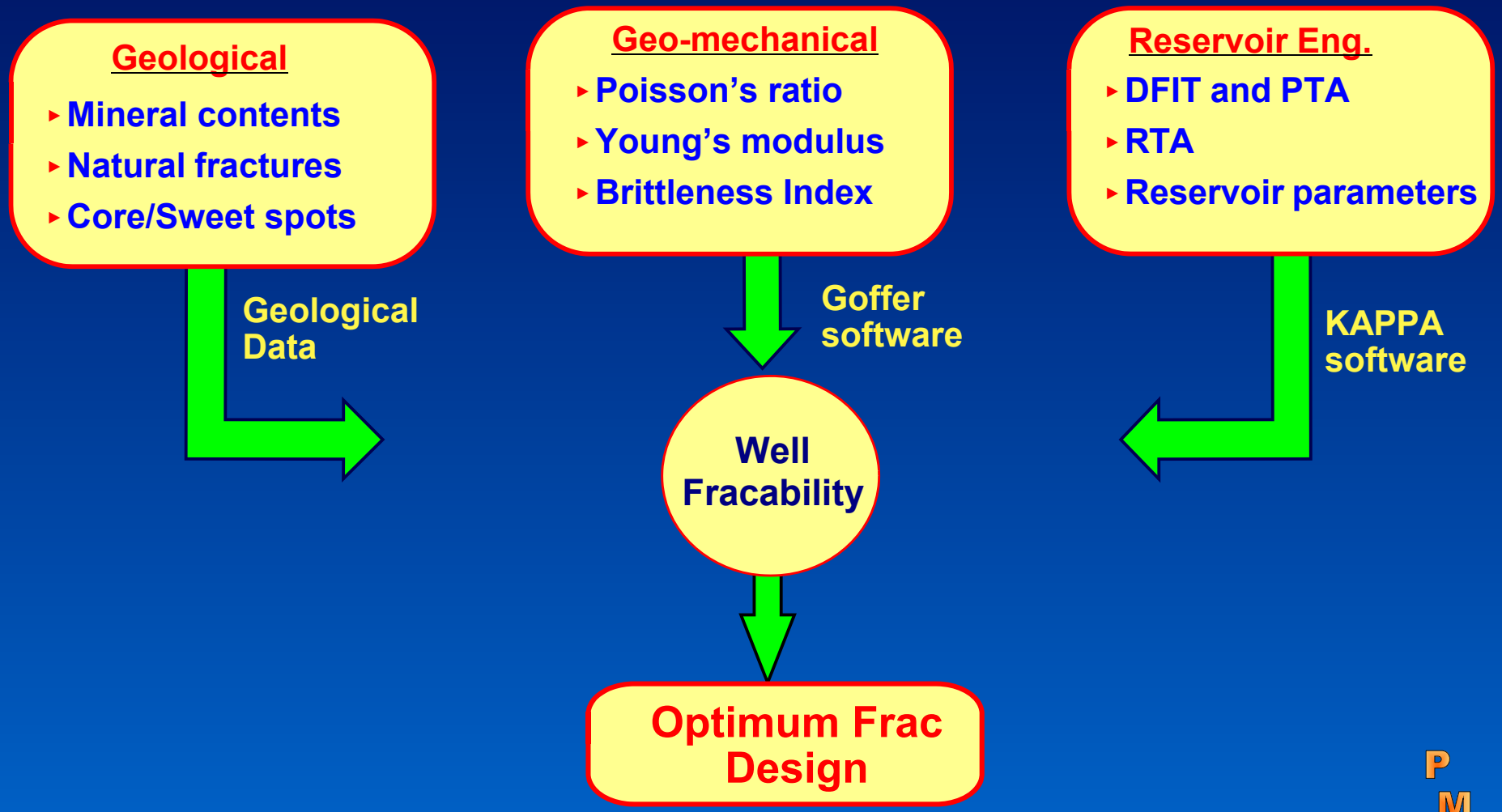
Petro Management Group - FracKnowledge

Full Well Frac Design and Optimization Services:



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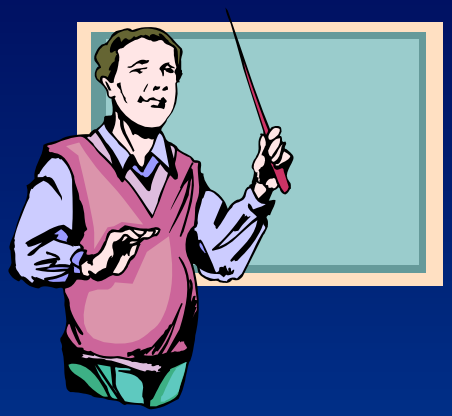
Industry and In-house Training Courses

- 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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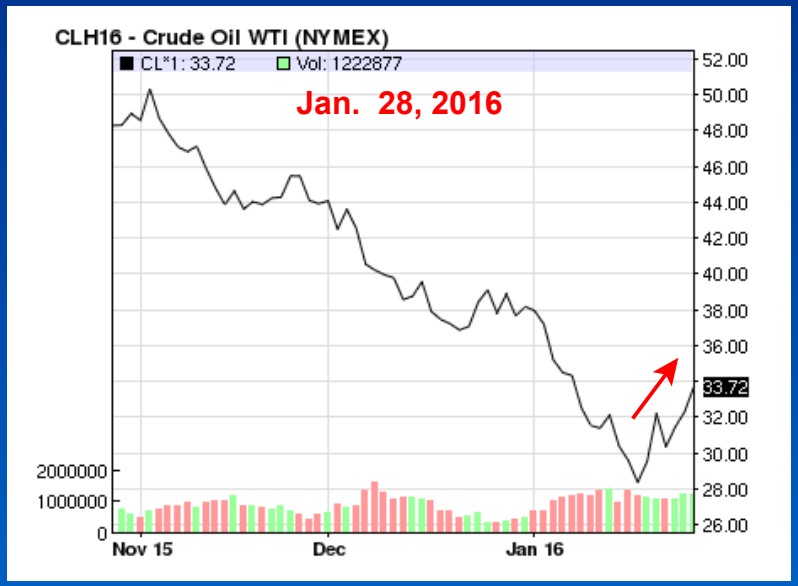
Our Business is Hanging on Rumours!



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Overview of Well Injection Tests

Agenda:

- Applications of injectivity tests
- Types of injectivity tests
- Operational aspects/problems of conducting injectivity tests
- Injection fall-off and step rate tests
  - Conventional testing
  - Unconventional
- Hall plot
- Application of Diagnostic Fracture injection Test (DFIT) or mini Frac
- Case study (Duvernay Shale Gas)
- Control of Well Flow-back, after frac treatment

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Applications of Injectivity Tests

- Optimize fluid injectivity for EOR and water disposal projects, by determining wellbore skin factor and permeability
- Monitor performance of injection/disposal wells
- Obtain information vital to frac treatment design, such as:
  - Closure pressure
  - Reservoir parameters (permeability and pressure)
  - Leak-off types
- Determine ceiling injection pressure for steam injection and EOR schemes
- Evaluate the draw-down limit during well flow-back period following frac treatments

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Tips to Maintain Well Injectivity

Injection of fluids into the reservoir can cause formation damage, which could be difficult to remove

- Rock-fluid damage (clay swelling/migration)
- Fluid-fluid damage (fluids incompatibility)
- Completion technique (clean up)
- Water quality
- Filter size

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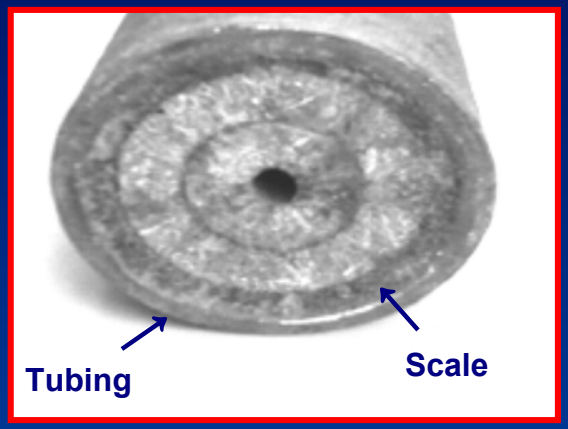
Preparations of Water Injectivity Testing

Some of the precautions that need to be considered prior to conducting an injectivity test are:



1. Perform laboratory tests to ensure injected and formation waters are compatible

2. Perform laboratory tests to ensure injected water is compatible with formation rock. The presence of swelling clays (smectite) could result in permanent formation damage. The addition of suitable chemicals (KCl) to reduce potential problems is highly recommended.

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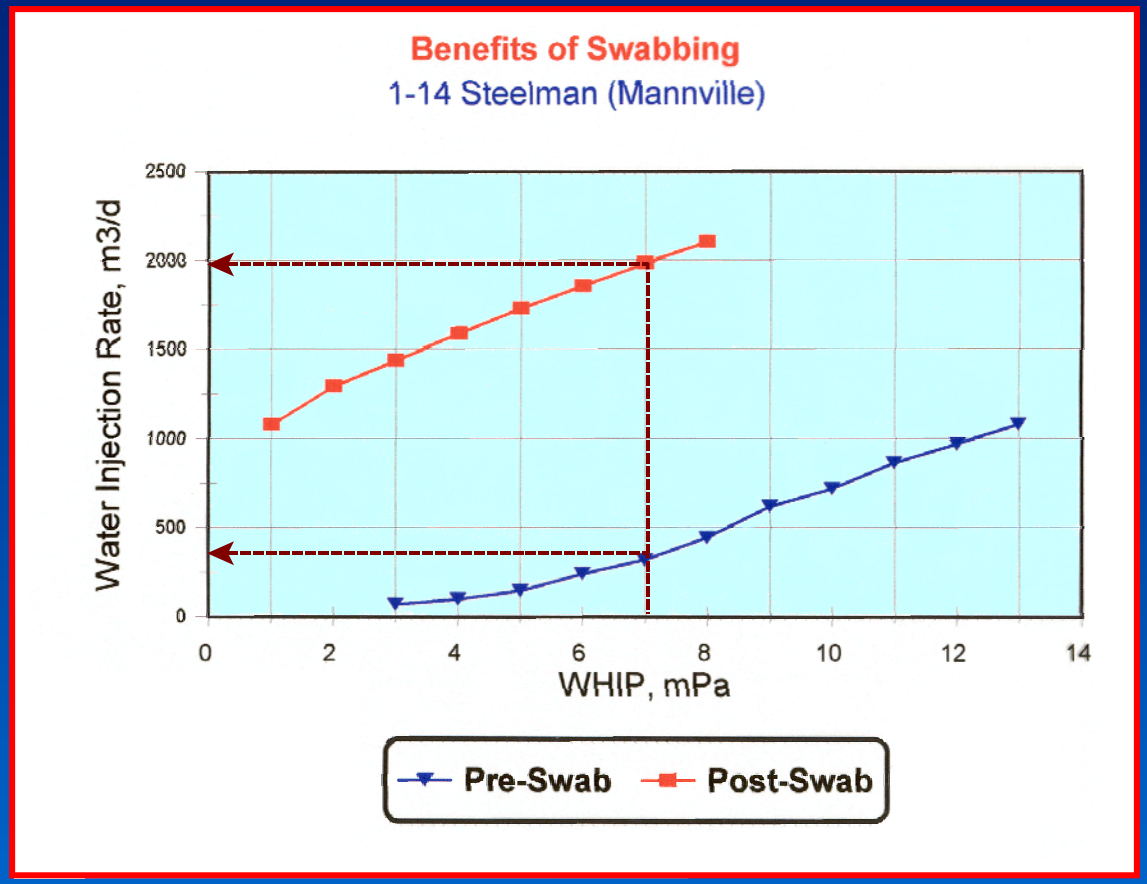
Completion of Injection Wells

3. Ensure clean wellbore condition prior to water injection by simply swabbing the well prior to water injection. The illustrated example of an injectivity test shows an increase in water injectivity over 500% at a WHIP of 8 000 kPa after swabbing.



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Water Quality

Problem:

Water quality should be maintained to avoid severe formation damage over a long period of injection, that could be irreversible

Solution:

Perform regular water sampling and water chemical analysis to maintain water quality, including:

- Oil contamination
- Oxygen content
- Fine size and amounts
- Bacterial content

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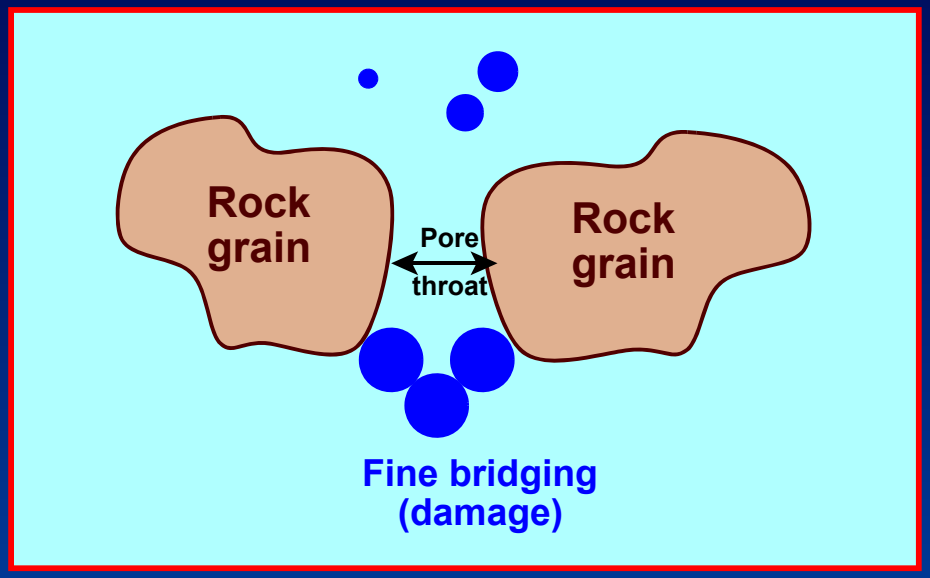
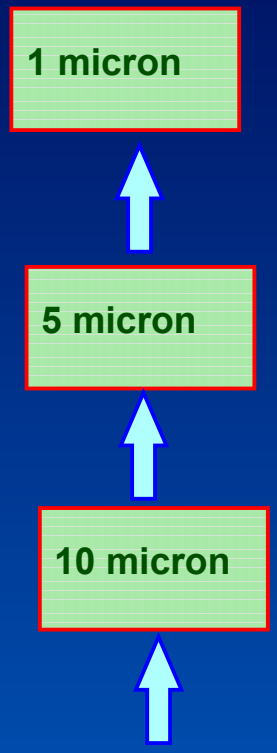
Water filter Size

K: permeability





Pore throat size = $\sqrt{K}$ = $\sqrt{100}$ = 10 microns

Filter size = 10/3 = 3 microns

Pore throat size = $\sqrt{K}$ = $\sqrt{10}$ ≈ 3 microns

Filter size = 3/3 = 1 microns

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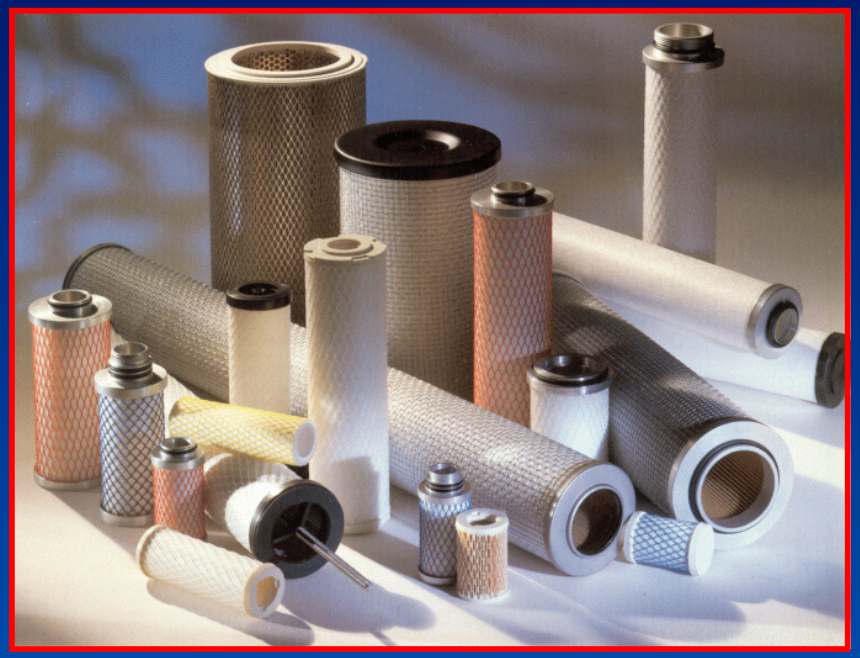
Water Filter



Water filter Cartridges

Water filter Unit

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Injectivity/fall-off and Step Rate Tests

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Injectivity/fall-off and Step Rate Tests

These tests are commonly conducted on disposal and injector wells.

- **Injectivity/fall-off** test is conducted to evaluate well injectivity by determining:
  - Formation permeability
  - Wellbore skin factor
  - Reservoir pressure
- **Step Rate test** to conducted to determine the formation breakdown pressure

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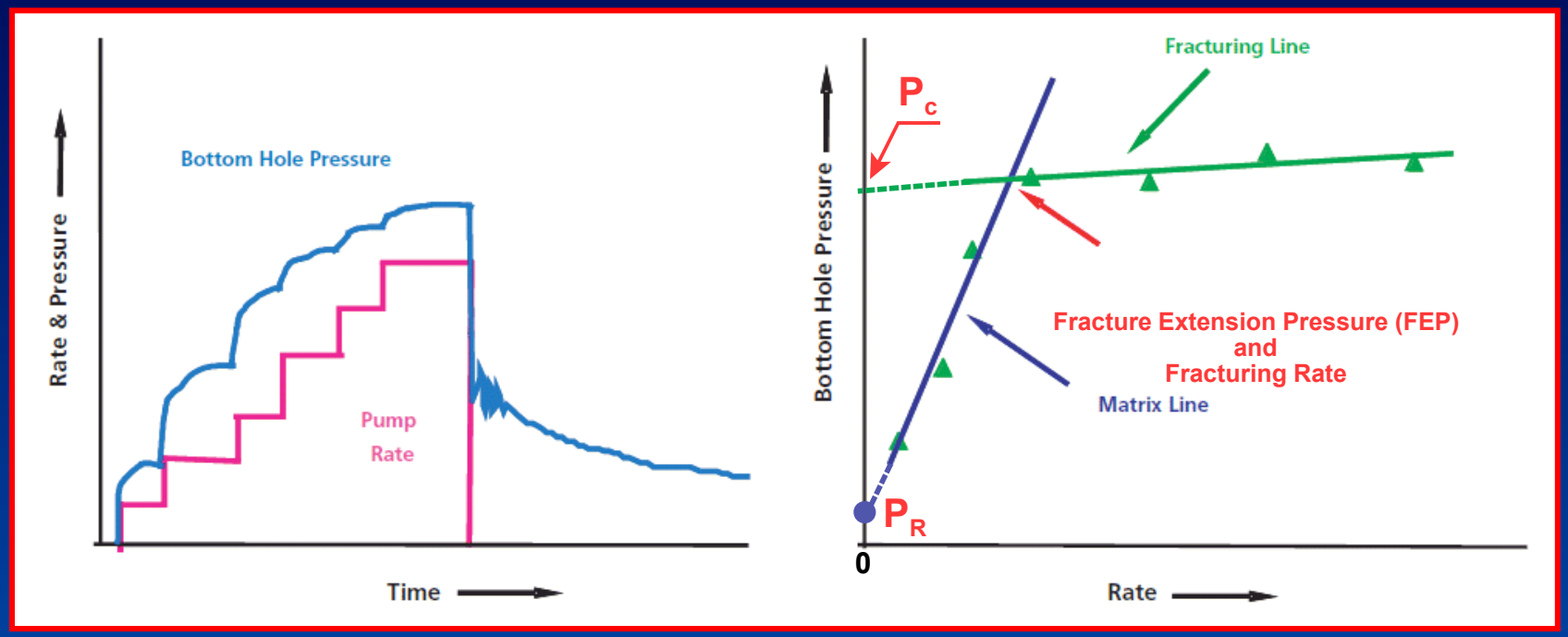
Step-rate Test



The idea behind this test is that by slowly increasing the injection rate in steps of equal time, a fracture will initiate and begins to grow, which will then produce minimal increases in bottom hole-injection pressure with increasing rate. The intercept of the fracture line at zero injection rate, yields the formation closure pressure (P_c)

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Design of Step-rate Test

- Estimate of the formation water injectivity capacity, using the generalized Darcy equation:

$$q_w = \frac{7.08 \times 10^{-3} \; k \; h \, (P_R - P_{wf})}{\mu_w \; B_w \; (\ln \frac{r_e}{r_w} - \frac{3}{4} + S)}$$

BWPD

Approximation of water injectivity:

$$i_w = 9.3 \times 10^{-4} \cdot \frac{k \cdot h \cdot \Delta P}{\mu_w}$$

Bwpd **into aquifer**

$$i_w = 2.3 \times 10^{-4} \cdot \frac{k \cdot h \cdot \Delta P}{\mu_w}$$

Bwpd **into oil zone**

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Design of Step-rate Test, cont.

- Estimate the formation breakdown (fracture) pressure from the Eaton's formula or from offset wells.
- Select the water step injection rates to ensure that a minimum of 3 steps are below the fracture pressure and 3 step rates above the frac pressure (see table below).
- It is always recommended to use non-damaging injection fluids, by adding 2% to 3% KCL

As % of Max. injectivity	
5%	Below Frac Pressure
10%	
20%	
40%	
60%	Above Frac Pressure
80%	
100%	

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Fracture Pressure (@ current Pressure)

Eaton's Formula

Estimate of Fracture Pressure (at Current Pressure)

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

Eaton's Formula

$$P_{(frac)} = NOB \left(\frac{u}{1 - u} \right) + P_{(PV)}$$

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	1,606	Psi
	11,075	KPa

Note:

Overburden gradient is 1.0 Psi/ft

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Interpretations of Step-rate Test

Several operational factors and reservoir parameters can influence the interpretation of Step-rate test results, such as:

- The presence of earlier frac
- The induced frac propagated into adjacent zones
- The change in the injected water quality
- Water temperature
- Skin factor

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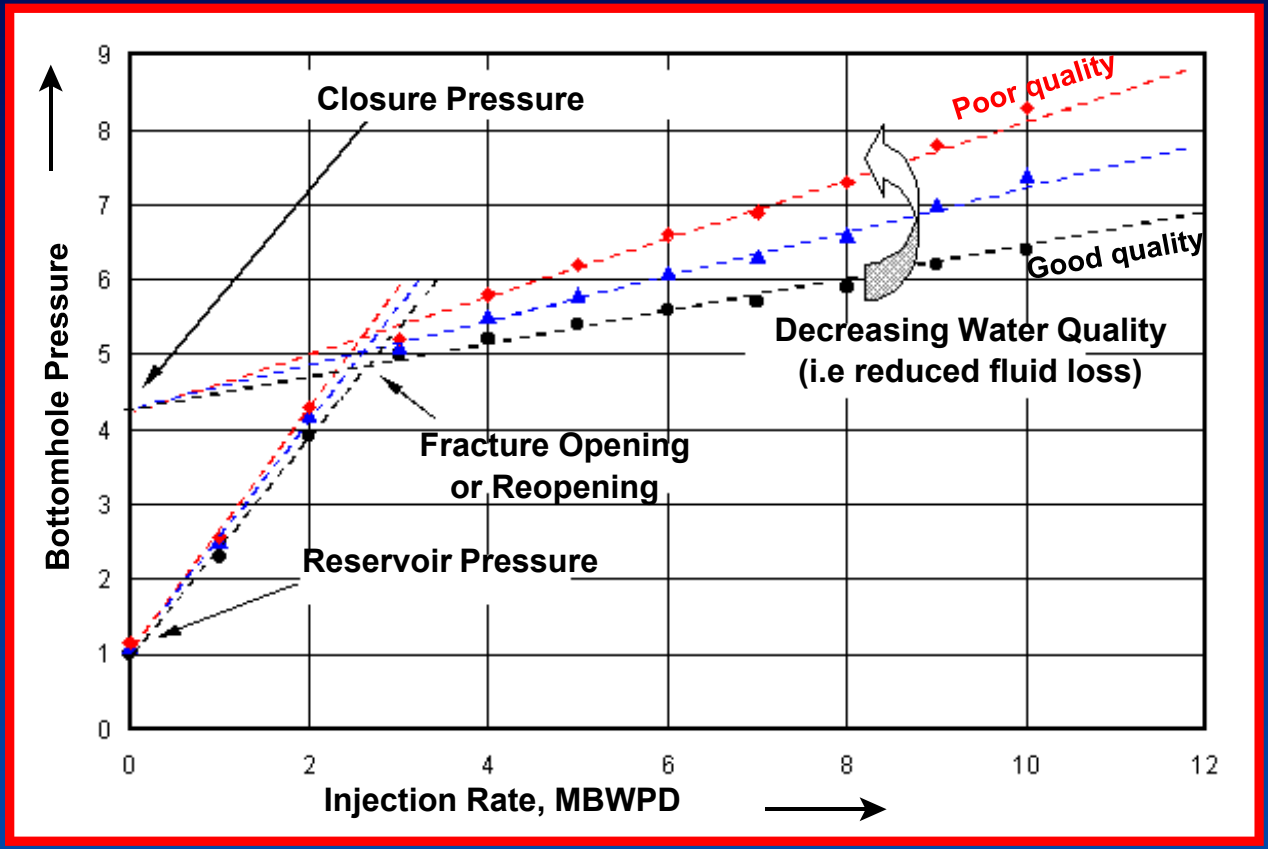
Effect of Water Quality



Most Prudhoe Bay injectors have alternated periods of seawater and produced water injection over the subsequent 10 years. It is found almost without exception that injectivity is poorer for produced water than for seawater, typically by 30-50%."

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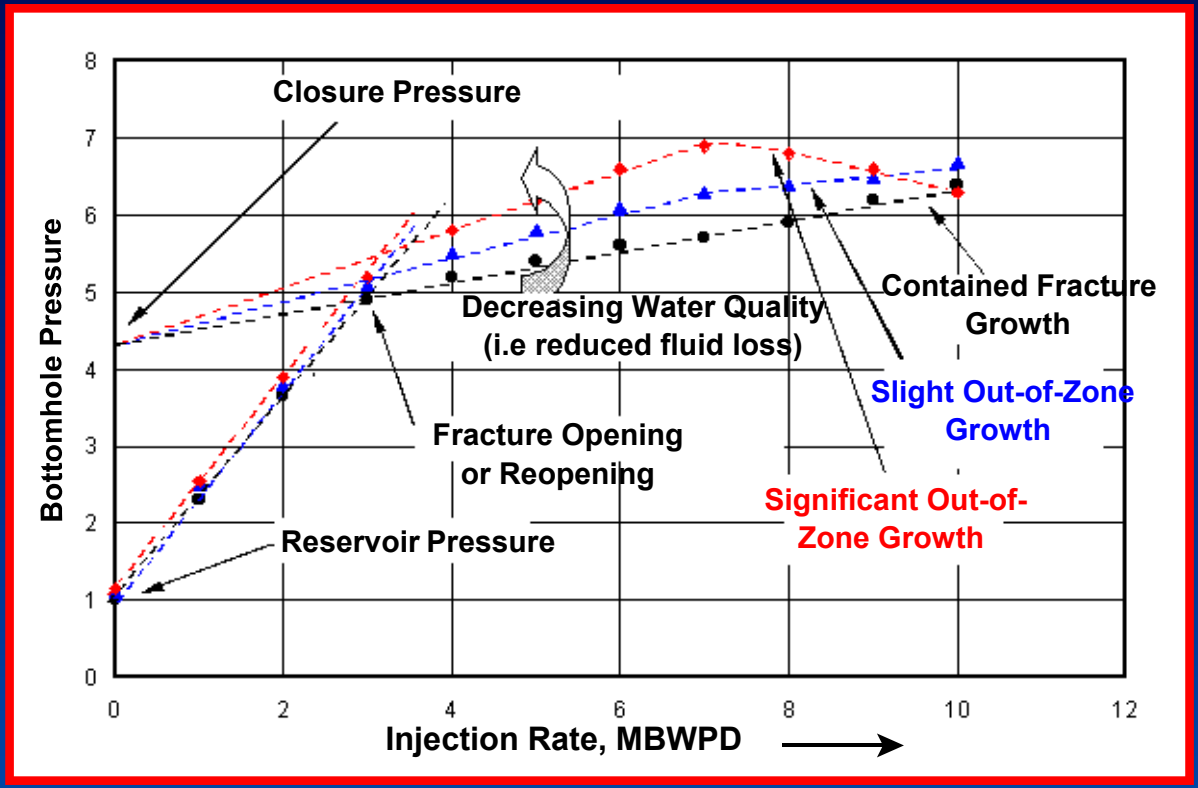
Out-of-zone Frac Growth



The decline in the injection pressure with increase in the injection rate, suggests out-of-zone frac growth

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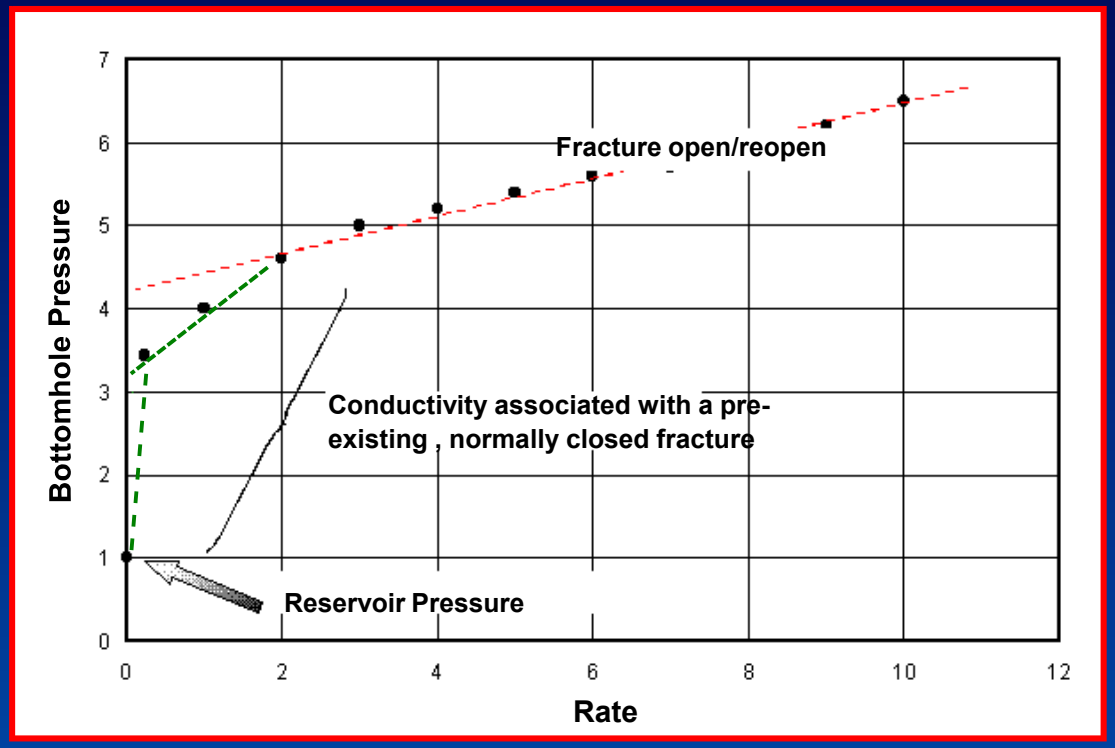
Pre-existing Hydraulic Fracture



An idealization of a closed (but still conductive) pre-existing hydraulic fracture. The extrapolation of the matrix injection data yields a straight line intercept value much higher the reservoir pressure

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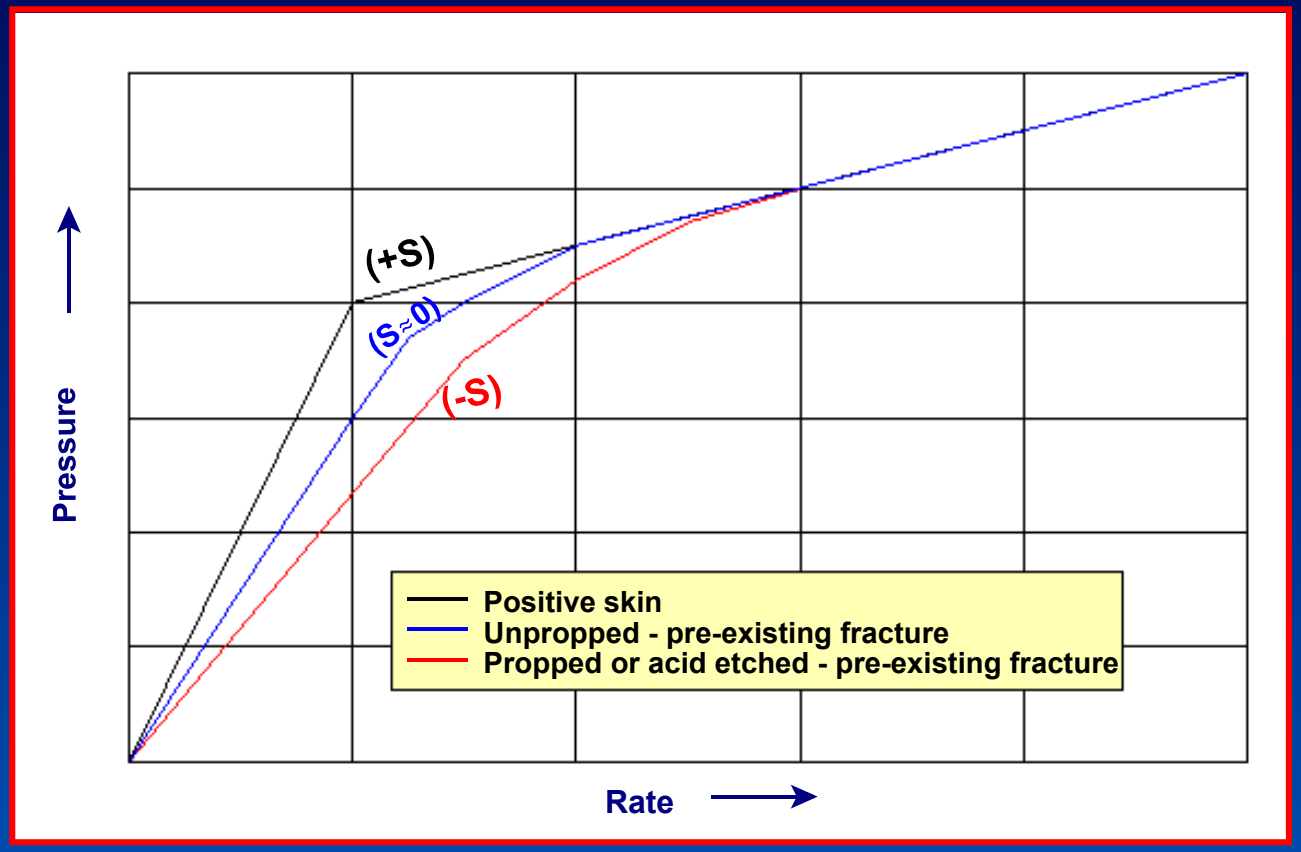
Effect of Wellbore Condition



Larger change in the slope of the straight lines indicates damaged wellbore condition

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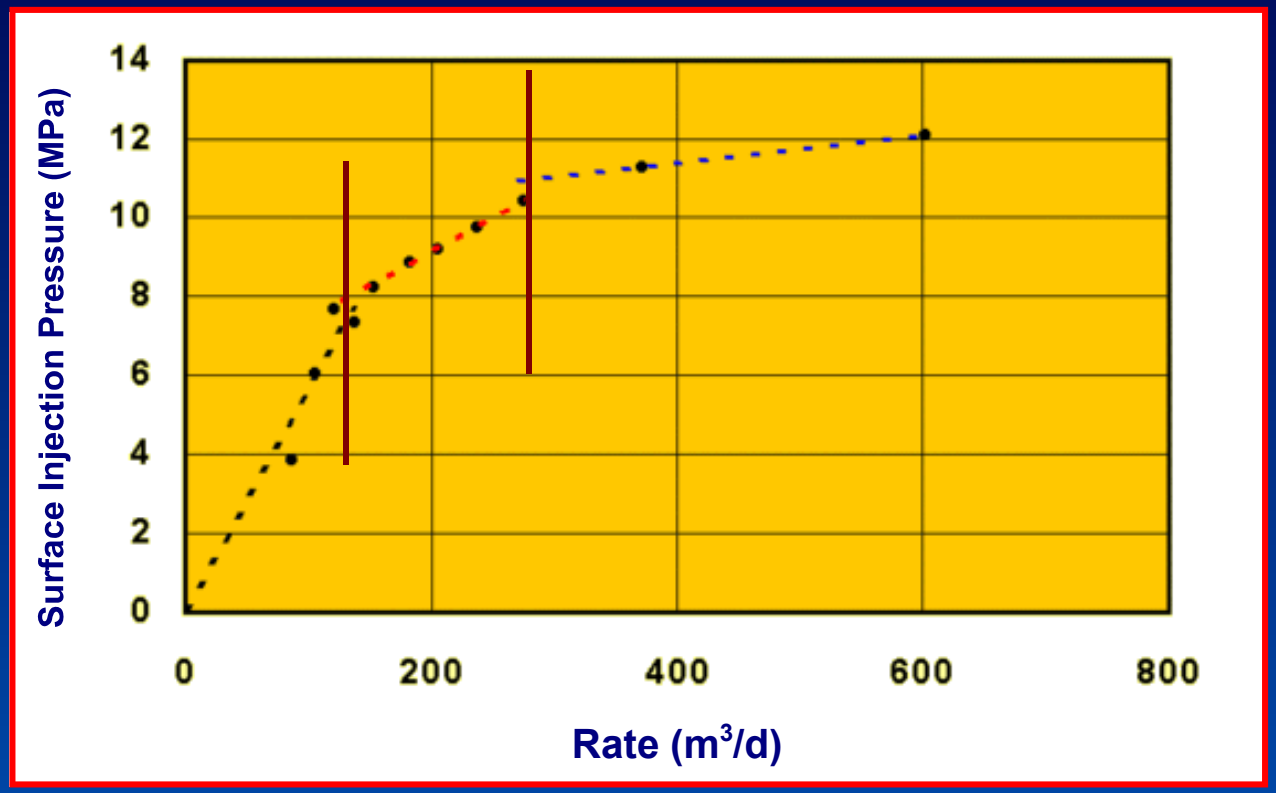
Effect of Other Factors



Multiple straight lines are evident for the following cases:

- More than one frac opening, or
- Variation in step injection time, or
- Variation in friction pressure loss

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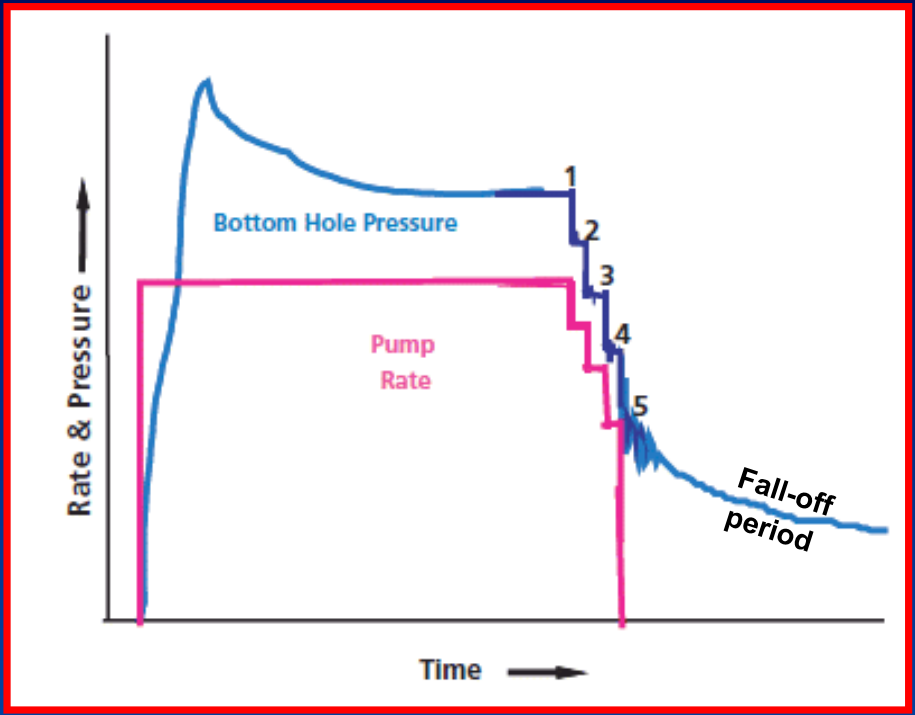
Step-down Test

Why step-down test?

A low injection rate (point #5), will reduce wellbore storage effects during the fall-off period, improving the analysis results.



This test is used to quantify perforation and near-wellbore pressure losses (caused by tortuosity) of frac'd wells, and as a result, provides information pertinent to the design and execution of the main frac treatments. Step-down tests can be performed during the shut-down sequence of a fracture calibration test.

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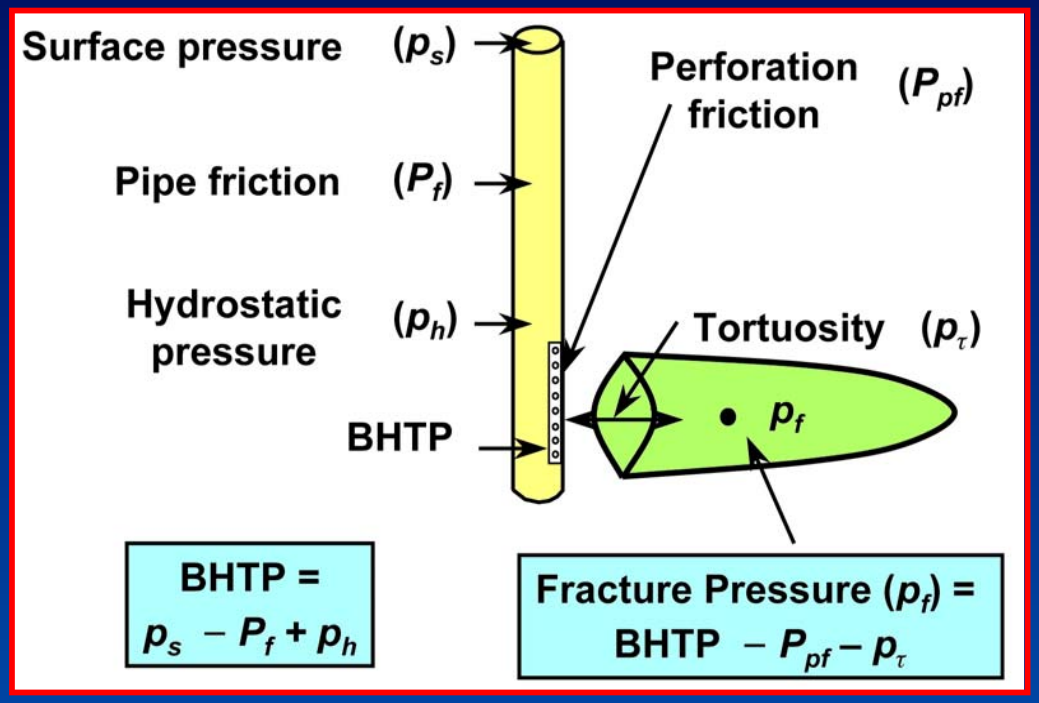
Why it is Important to Determine Near Wellbore Pressure Drop?



- It is important to know the pressure in the formation (P_f) when designing a frac treatment.
- The measurement of BHTP in the wellbore could be much different than the frac pressure because of the pressure drop near the wellbore due to friction in the perforation (P_{pf}) wellbore tortuosity (P_τ)

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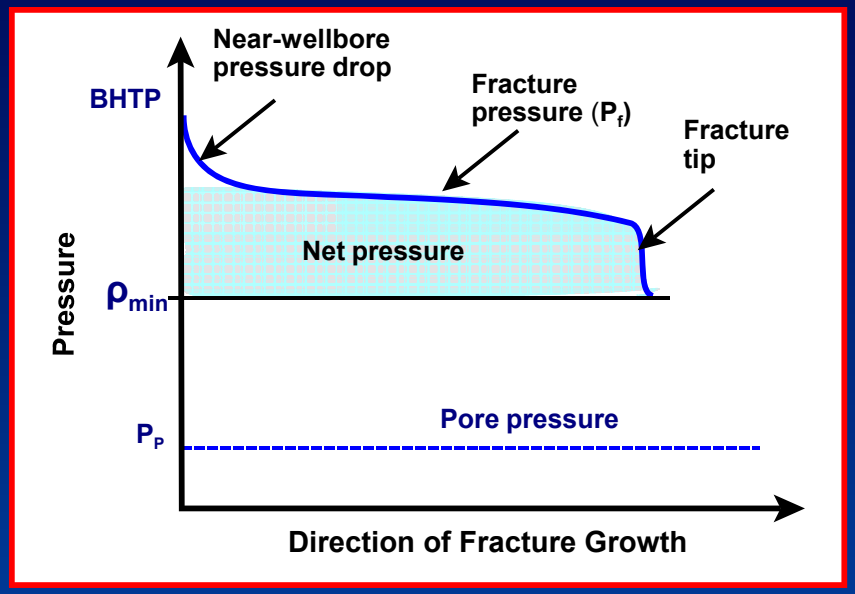
Design of Step-down Test

- To measure the near-wellbore pressure drop, the net pressure in the fracture needs to be relatively constant during the step-down portion of the test.
- To do this, the step-down test is started by injecting into the well for 10 to 15 minutes. **Experience has shown** that, in most cases, the net pressure is relatively stable after approximately 10 to 15 minutes of injection



- If the net pressure in the fracture is relatively stable, then the change in bottomhole injection pressure as the injection rate is reduced will be a function of the near-wellbore pressure drop.
- The injection rate is then "reduced in steps" to a rate close to zero
- The injection rate at each step should be held constant for approximately 1 minute so the stabilized injection pressure can be measured

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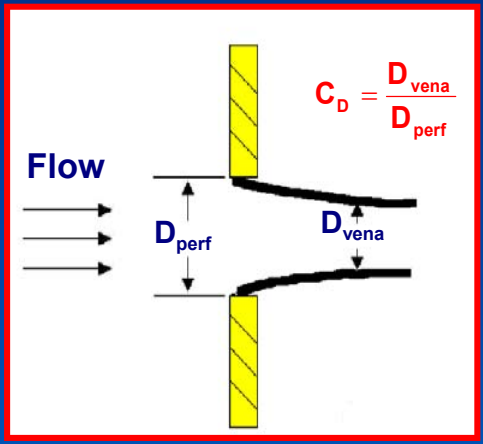
Perforation Pressure Drop

$$\Delta P_{perf} = K_{perf} \cdot q^2$$

$$K_{perf} = \frac{1.975\,\gamma_{inj}}{C_d^2 \cdot n_{perf}^2 \cdot d_{perf}^4}$$

Where:

- ΔP_{perf} Perforation pressure drop, psi
- q Flow rate, Stb/d
- K_{perf} Perforation pressure drop coefficient, psi/(std/d)^2
- γ_{inj} Specific gravity of injected fluid
- C_d Discharge coefficient, usually 0.95
- n_{perf} Number of perforations
- d_{perf} Diameter of perforation, in



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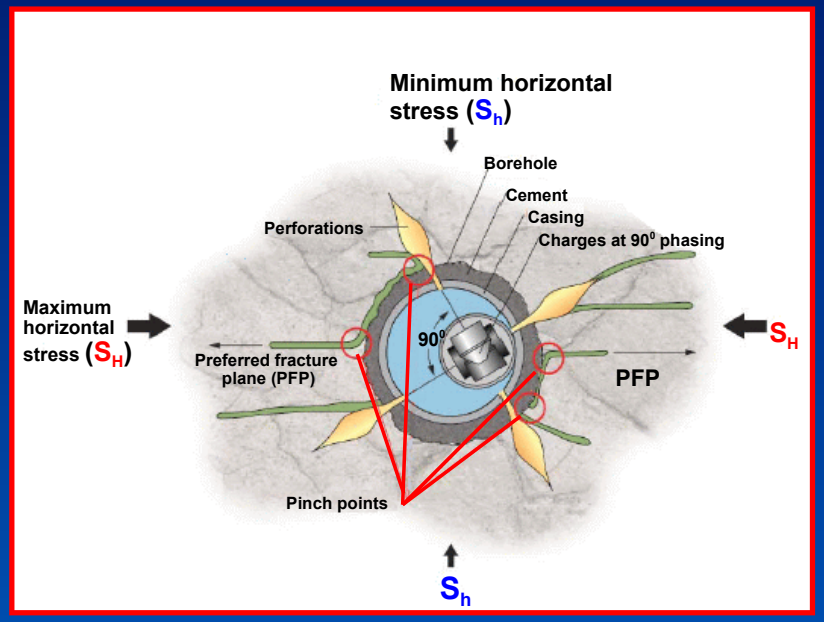
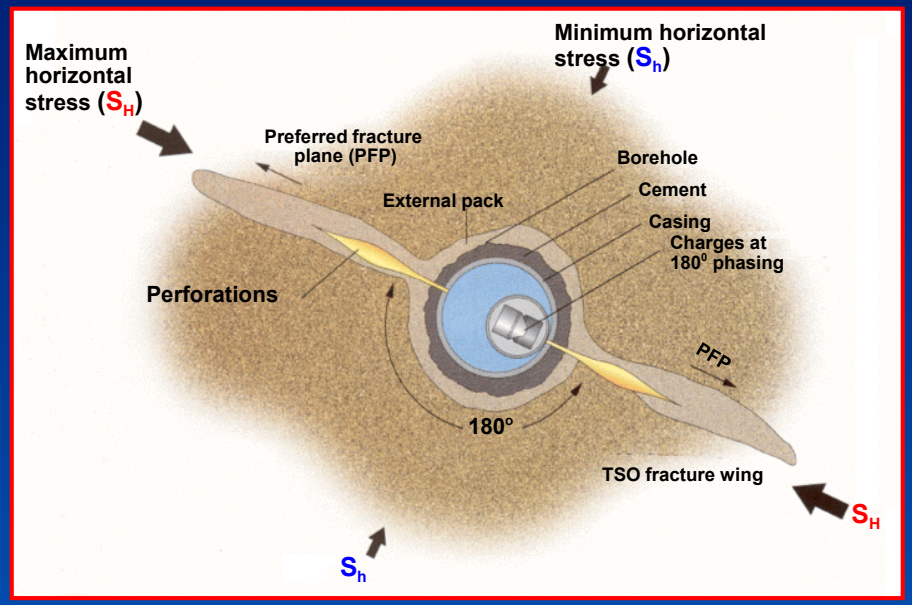
Pressure Drop Due to Wellbore Tortuosity

Wellbore tortuosity can cause a pressure drop of the fracturing fluids as it passes through a region of restricted flow or complex flow path between the perforations and the main fracture





Perforating in the other direction than maximum hz. stress will increase wellbore tortuosity and high wellbore pressure drop

Perforating in the direction of maximum hz. Stress reduces or eliminates tortuosity, which increases fracture initiation and treating pressures

Source: Schlumberger

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Tortuosity Pressure Drop

$$\Delta P_{tort} = K_{tort} \cdot q^{\alpha}$$

Where:

- ΔP_{tort} Tortuosity pressure drop, psi
- q Flow rate, Stb/d
- K_{tort} Tortuosity pressure drop coefficient, psi/(Stb/d)^2
- α Tortuosity pressure drop exponent, usually 0.5

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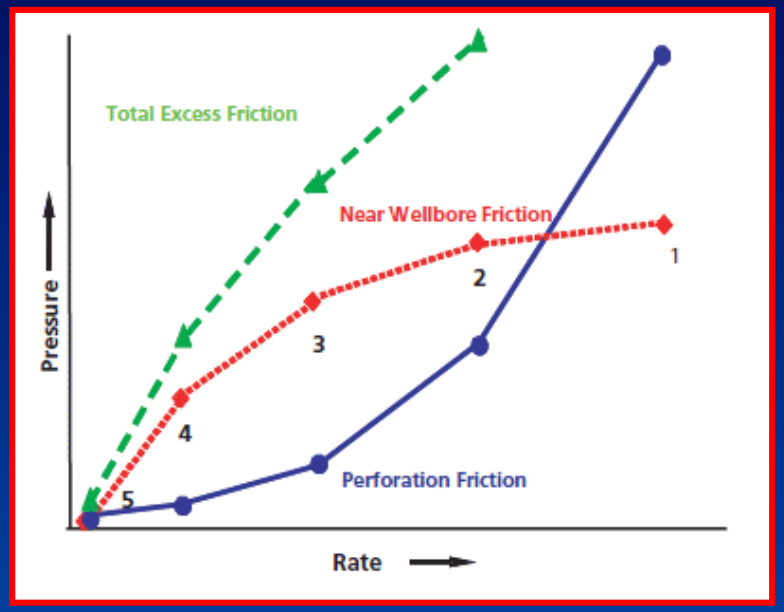
Comparison of Perforation/Tortuosity Pressure Drops

$$\Delta p_{tort} \propto q^{0.5}$$

$$\Delta p_{perf} \propto q^{2}$$



Injection Rate	Bottomhole Treating Pressure	Calculated Bottomhole Treating Pressure	$\Delta p_{perf+tort}$	$(\Delta p_{perf+tort})_{calc}$	$(\Delta p_{perf})_{calc}$	$(\Delta p_{tort})_{calc}$
bbl/min	psi(a)	psi(a)	psi	psi	psi	psi
9.07	4055.00	4043.06	960.66	948.72	494.05	454.67
6.52	3700.56	3734.73	606.22	640.40	255.01	385.38
4.05	3530.23	3496.72	435.90	402.39	98.54	303.85
2.82	3385.98	3395.45	291.64	301.11	47.69	253.43
0.00	3094.34	3094.34	0.00	0.00	0.00	0.00

Model Parameters
p_{frac} 3094.34 psi(a)

Perforation Pressure Losses
k_{perf} 6.006 psi/(bbl/min)^2

Advanced
n_{perf}
$(n_{perf})_{eff}$
γ_{inj}
C_d
d_{perf} in

Tortuosity Pressure Losses
k_{tort} 150.971 psi/(bbl/min)$^{\alpha}$
α_{tort} 0.500

R^2 0.995

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Injectivity Fall-off Test

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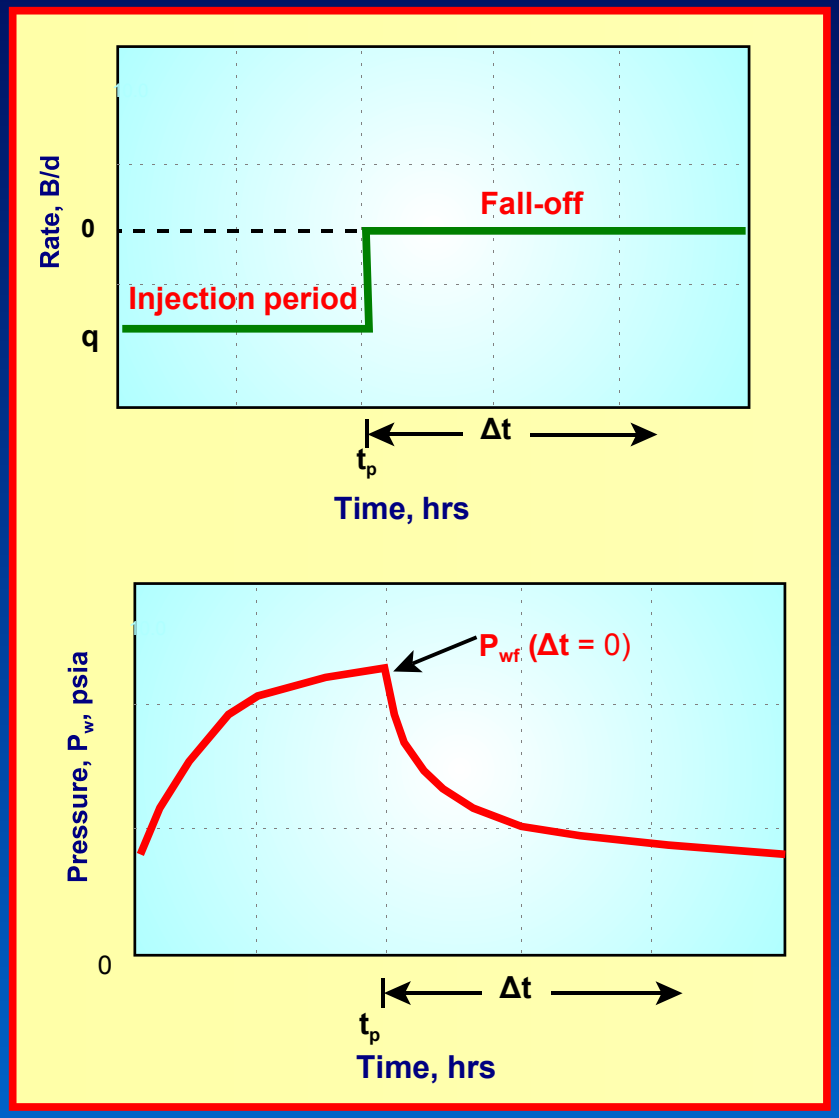
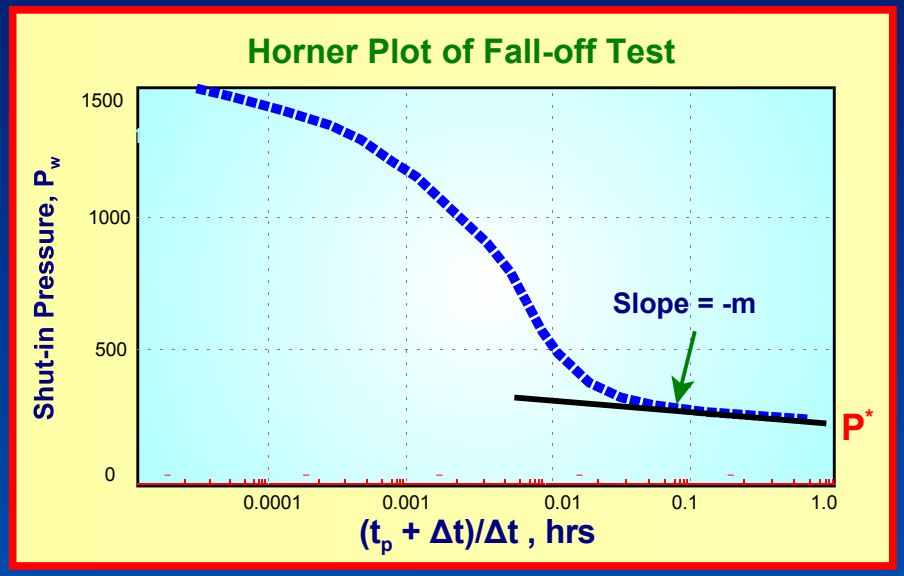
Injection/Pressure Profiles





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Case Study

South Pierson Unit - Manitoba/Canada

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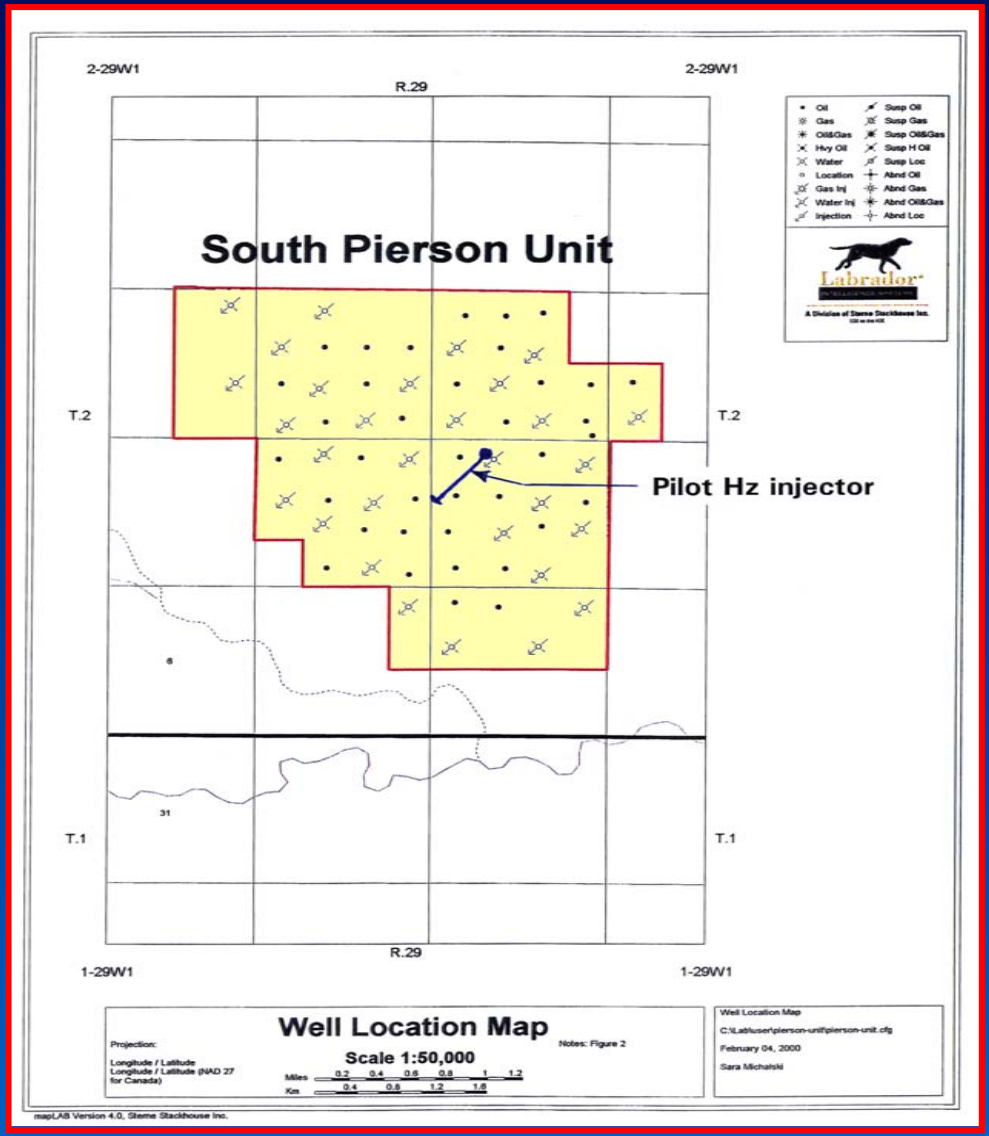
Injectivity Problems



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Reasons of Injectivity Problems

- Reservoir pressure declined from 10.6 to 3.3 mPa (V.R.R = 29%)
- Formation: Spearfish permeability 1 to 10 mD
- Underlaying **thief zone**: Alida (k up to 100 mD) is taking 75% of injected water
- Vertical Spearfish injectors averaging only 3 m^3/d
- Large Spearfish frac. treatment resulted in communication with the Alida
- Injectivity/fall-off tests indicates that injection has been conducted much higher than the formation breakdown pressure
- Large filter size (10 microns) was used allowing deep formation damage

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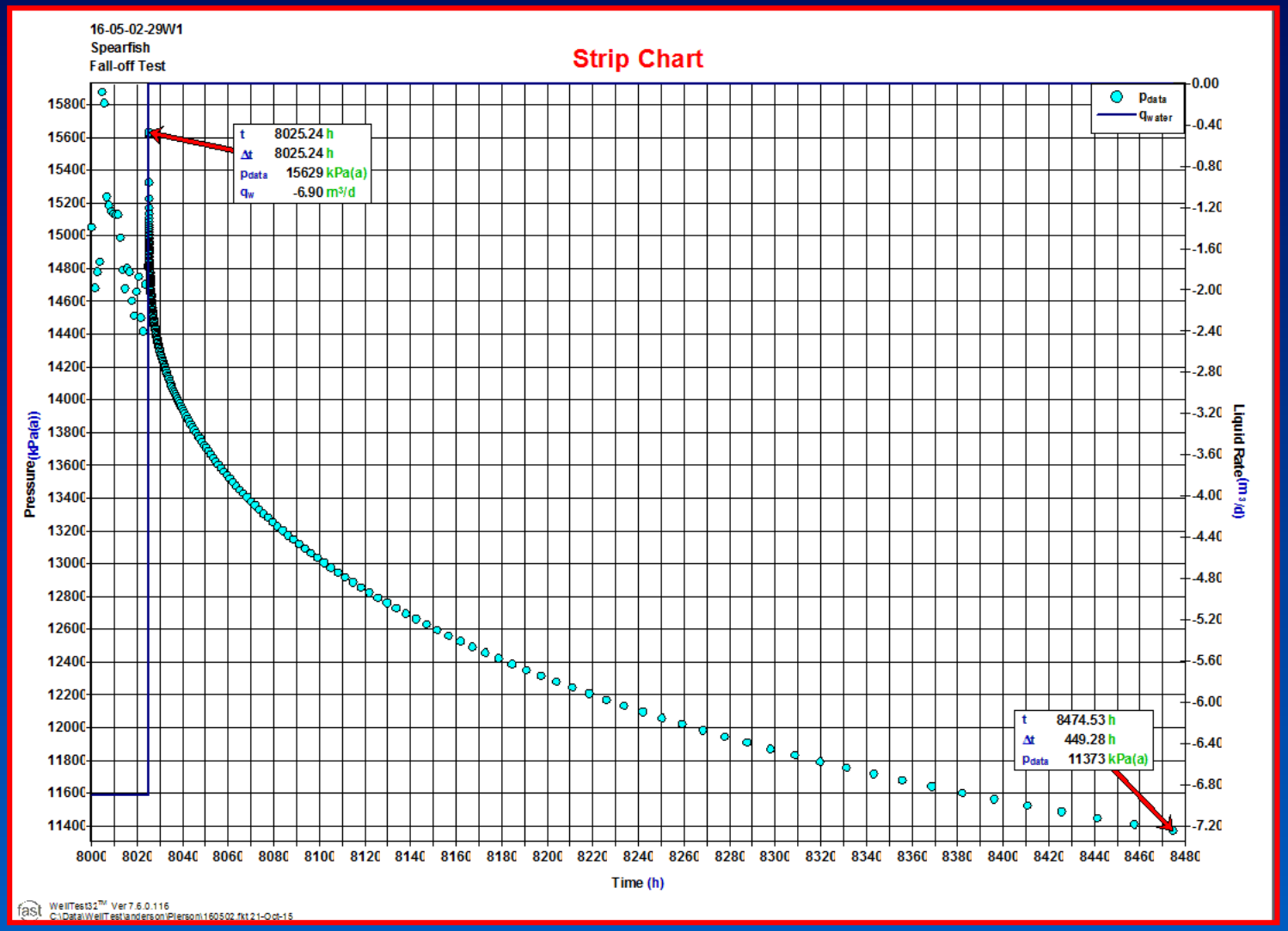
Typical Injectivity/fall-off Pressure Profile



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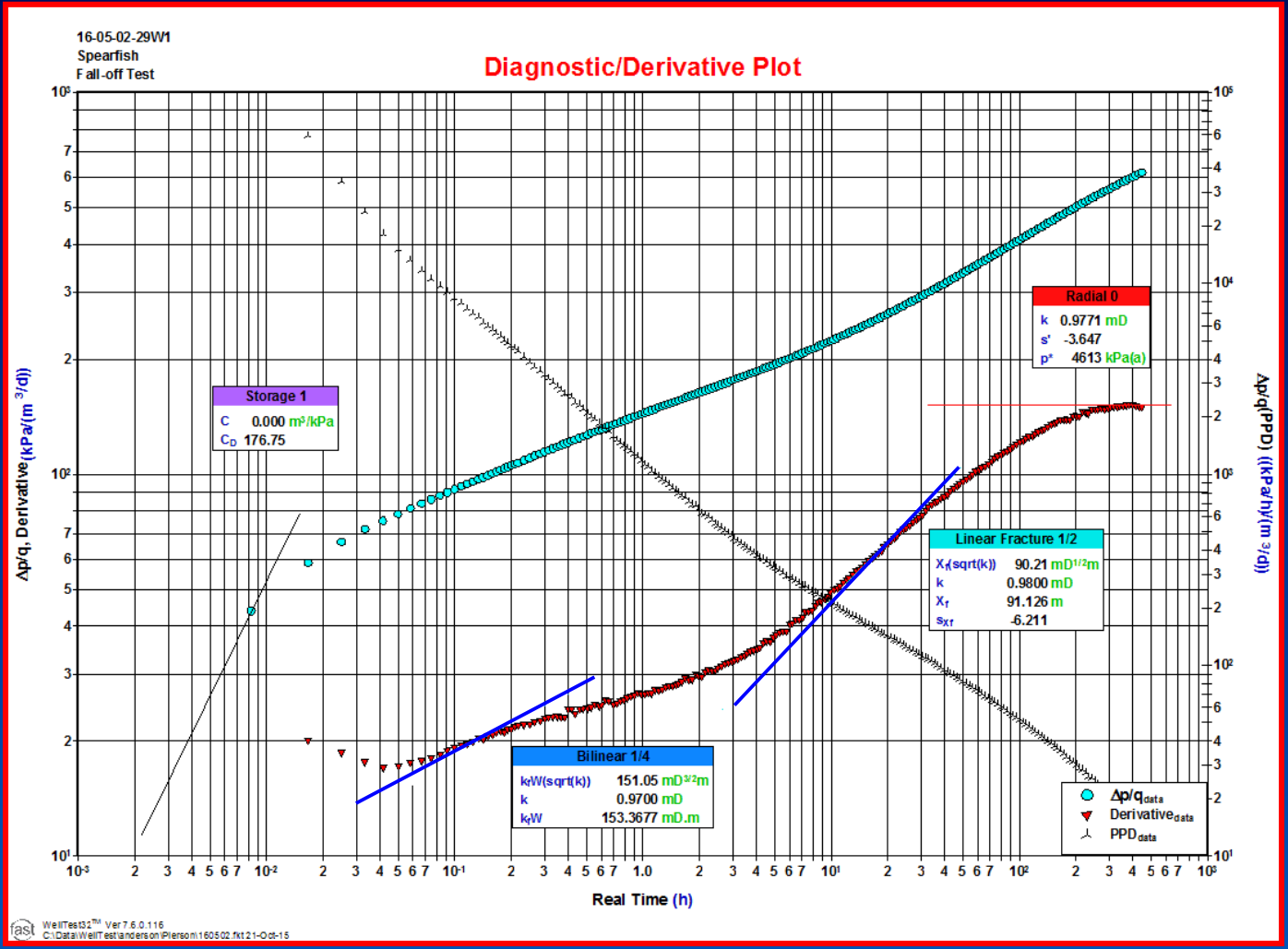
Diagnostic/Derivative Plot



All flow regimes are well defined, suggesting the well is fraced!, from the presence of Linear and Bilinear flow regimes.

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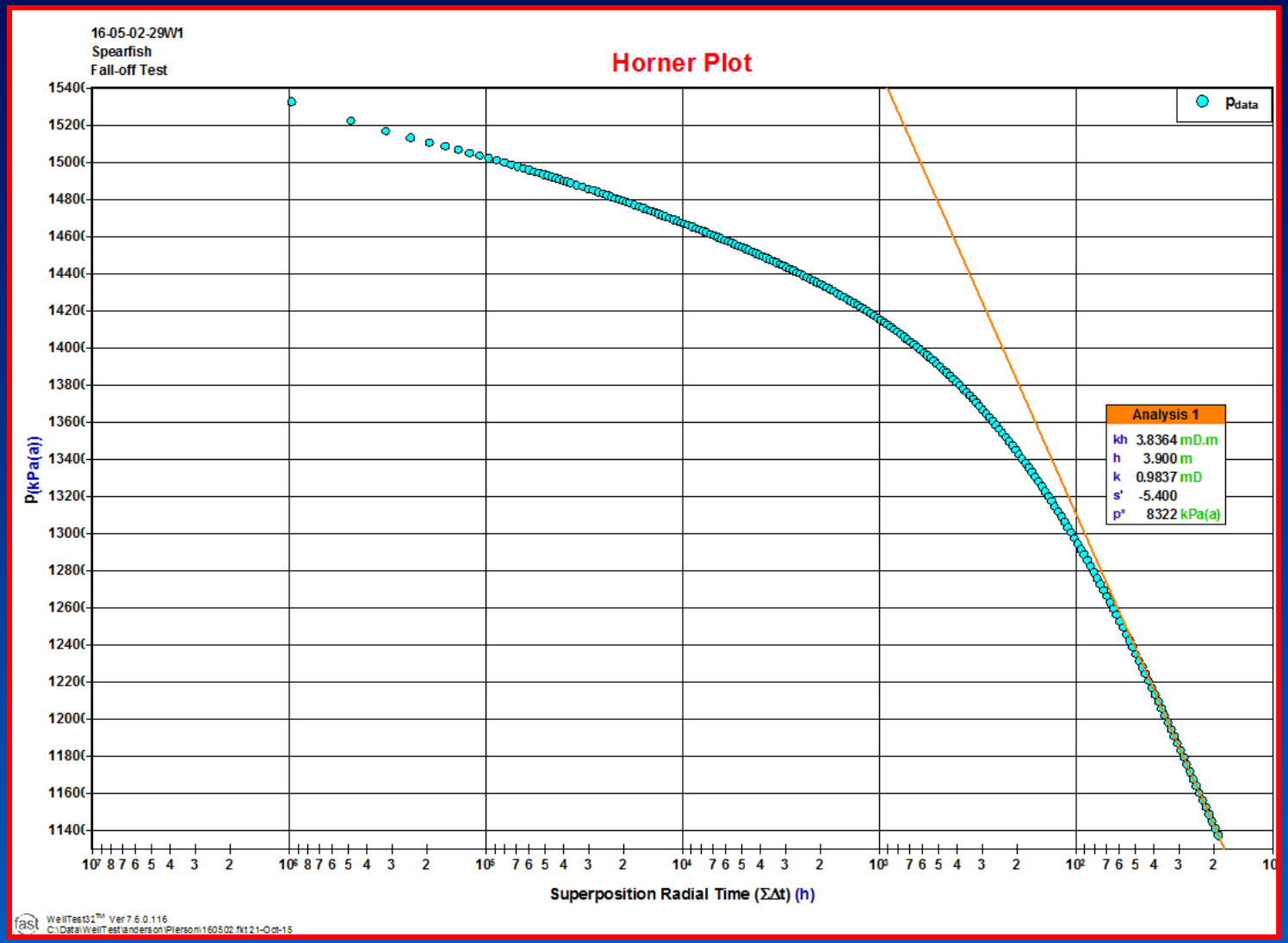
Horner Plot



The negative skin factor of -5.4 confirms the well is fraced

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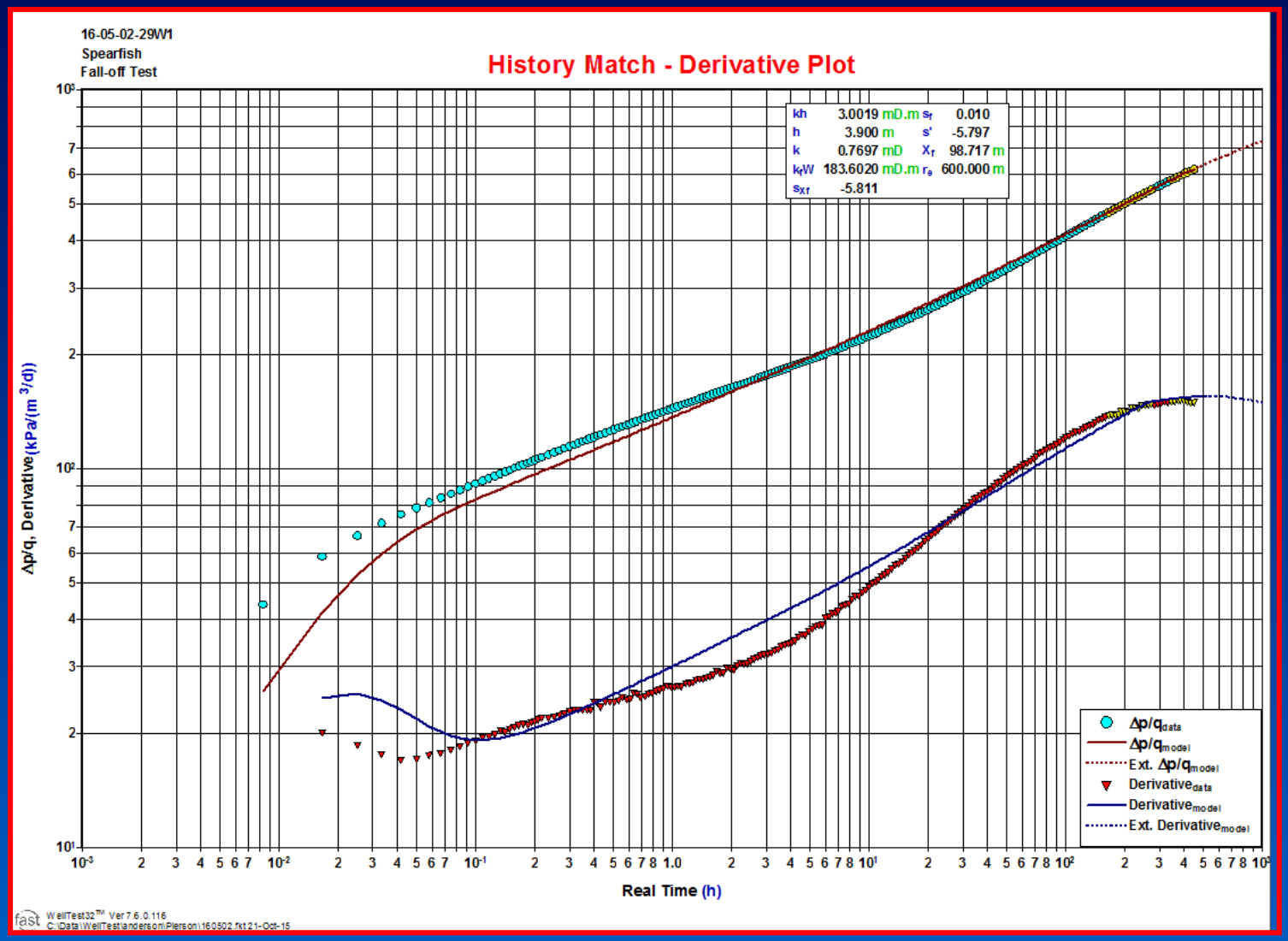
History Match - Pressure Derivative Plot



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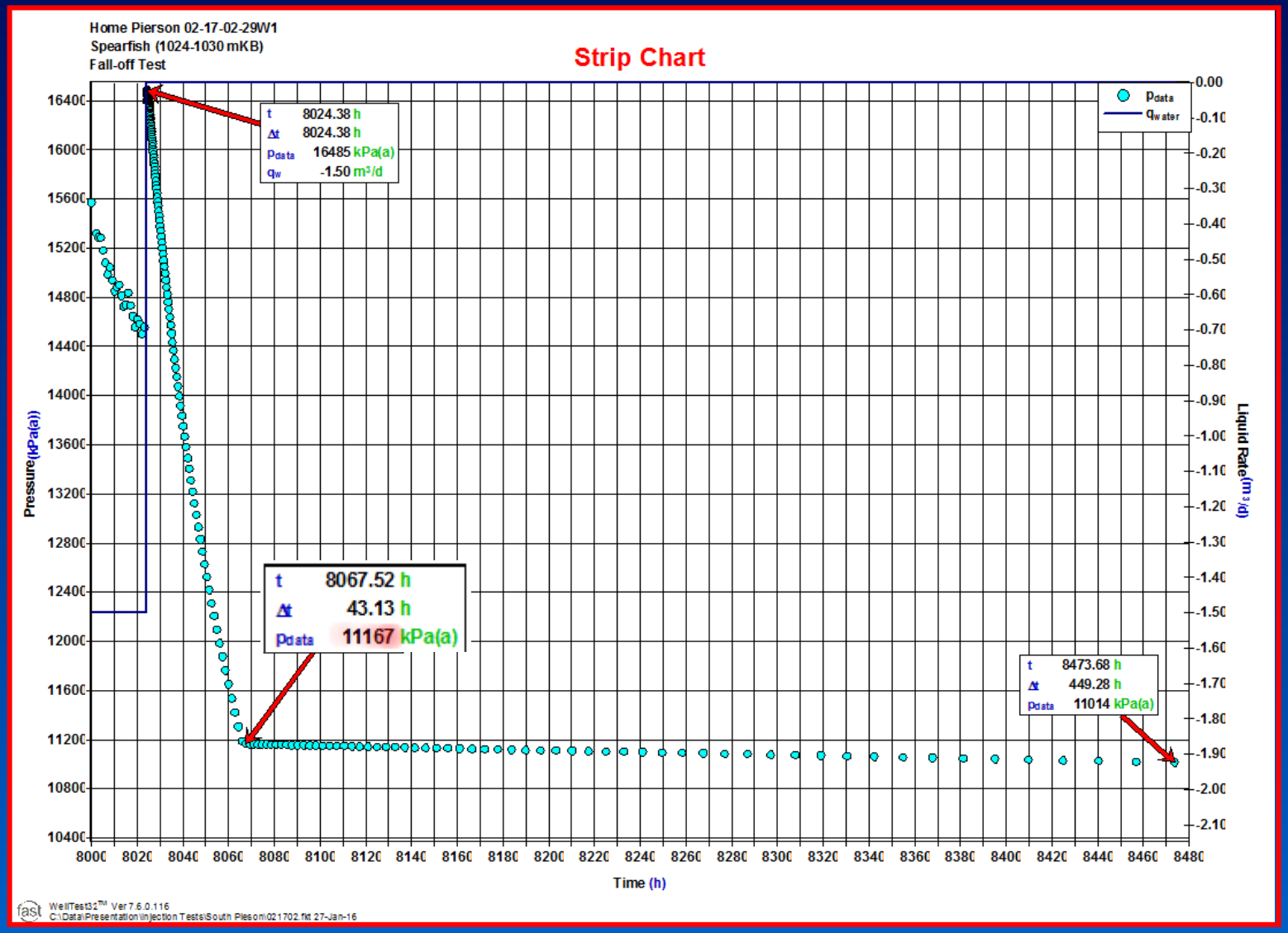
Major Pressure Anomaly (Fall-off Data)



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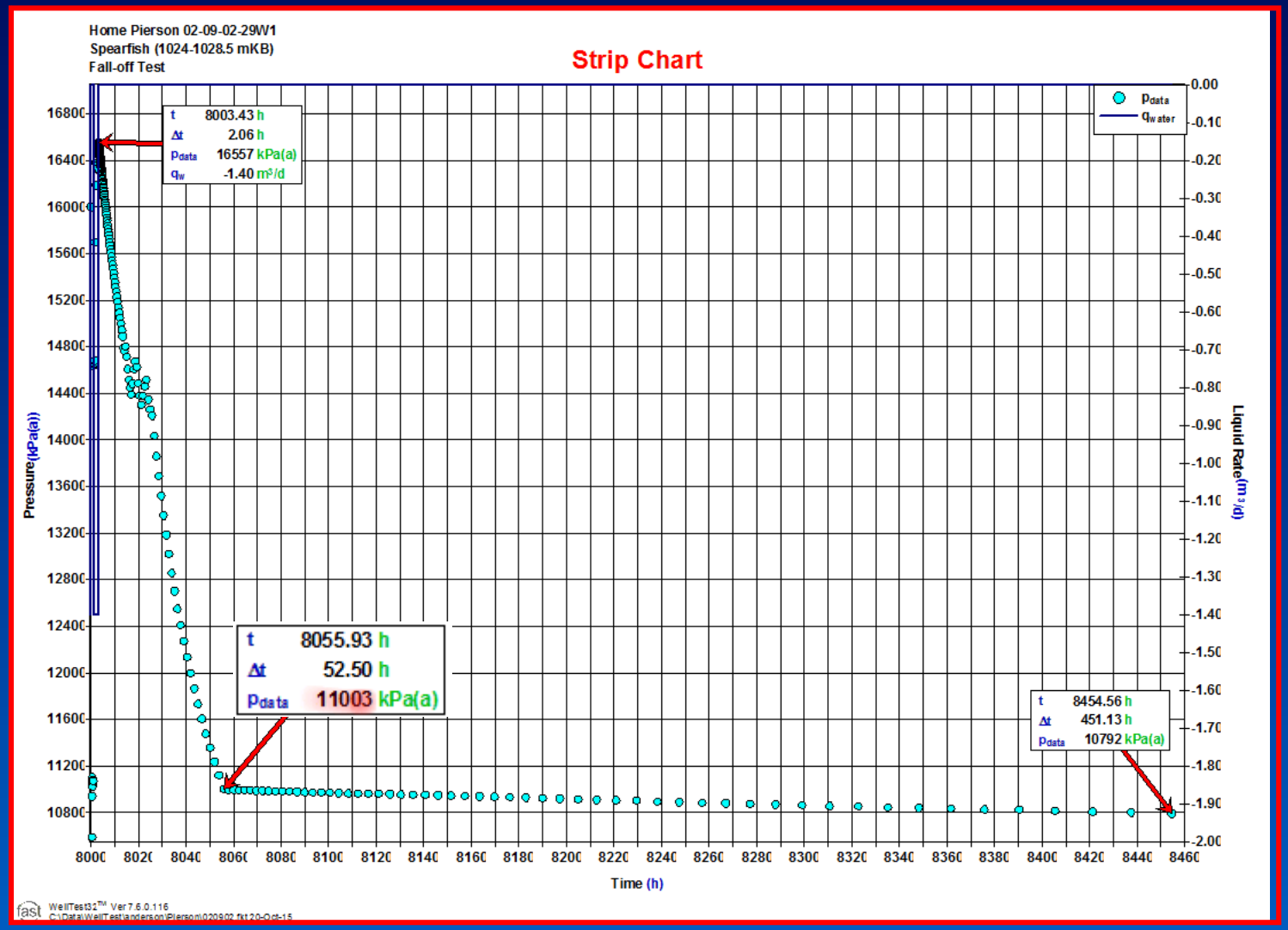
Another Injector showing Similar Anomaly



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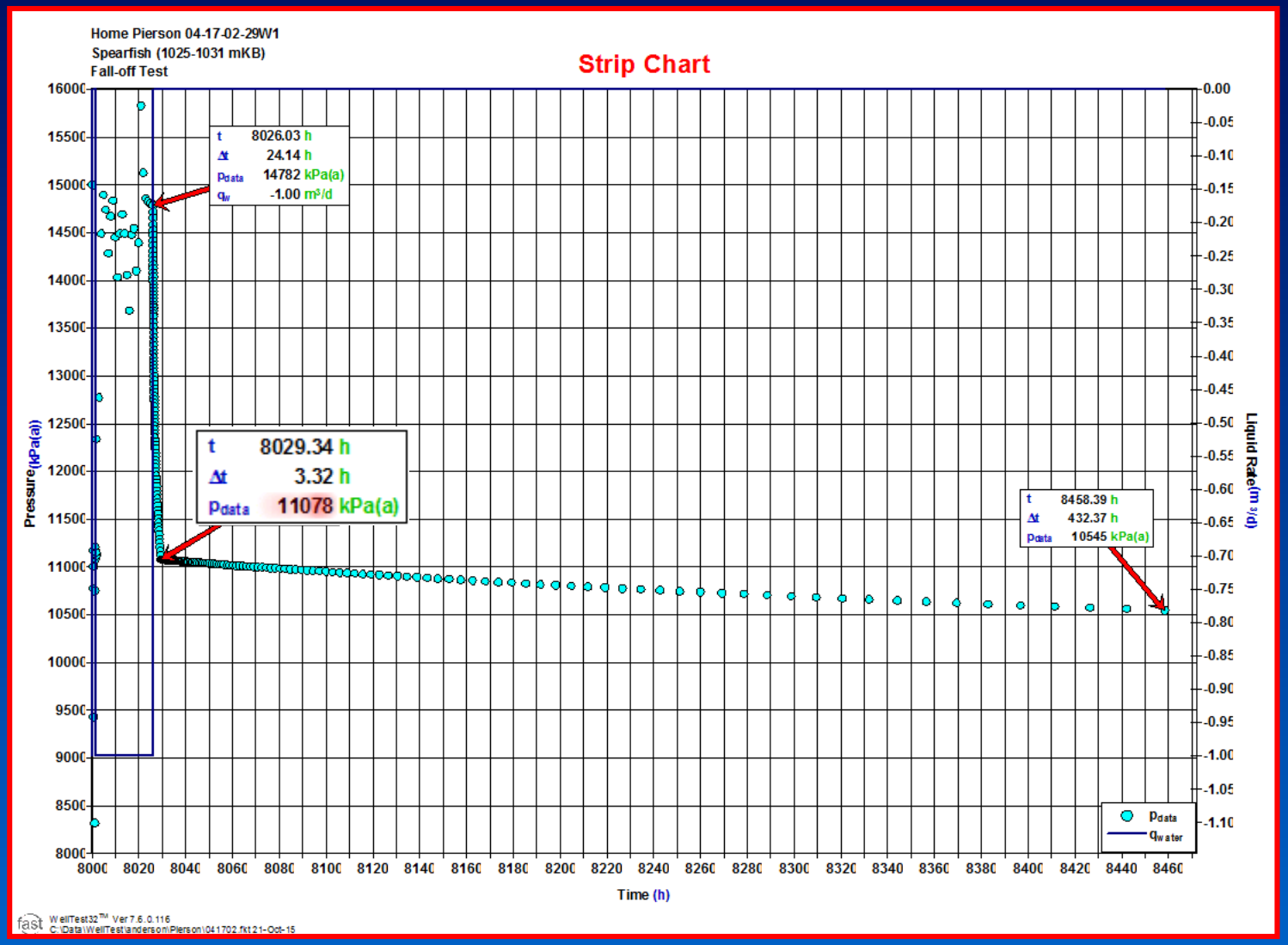
What is Common about the Pressure Anomalies?



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Fracture Pressure (@ current Pressure)

Eaton's Formula

Estimate of Fracture Pressure (at Current Pressure)

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

Eaton's Formula

$$P_{(frac)} = NOB \left(\frac{u}{1 - u} \right) + P_{(PV)}$$

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	1,606	Psi
	11,075	KPa

Note:

Overburden gradient is 1.0 Psi/ft

PMG

Fracture Pressure (@ Initial Pressure)

Eaton's Formula

Estimate of Fracture Pressure (at Initial Pressure)

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

Eaton's Formula

$$P\ (frac) = NOB\ \left(\frac{u}{1-u}\right) + P\ (PV)$$

Psi/ft

Where :

P (frac) :	Fracture Pressure Gradient			0.667	Psi/ft
NOB :	Net Overburden Pressure Gradient			0.545	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			0.455	Psi/ft
P	Initial Reservoir Pressure			1537	Psi
D :	Depth			3378	ft

Summary Results:

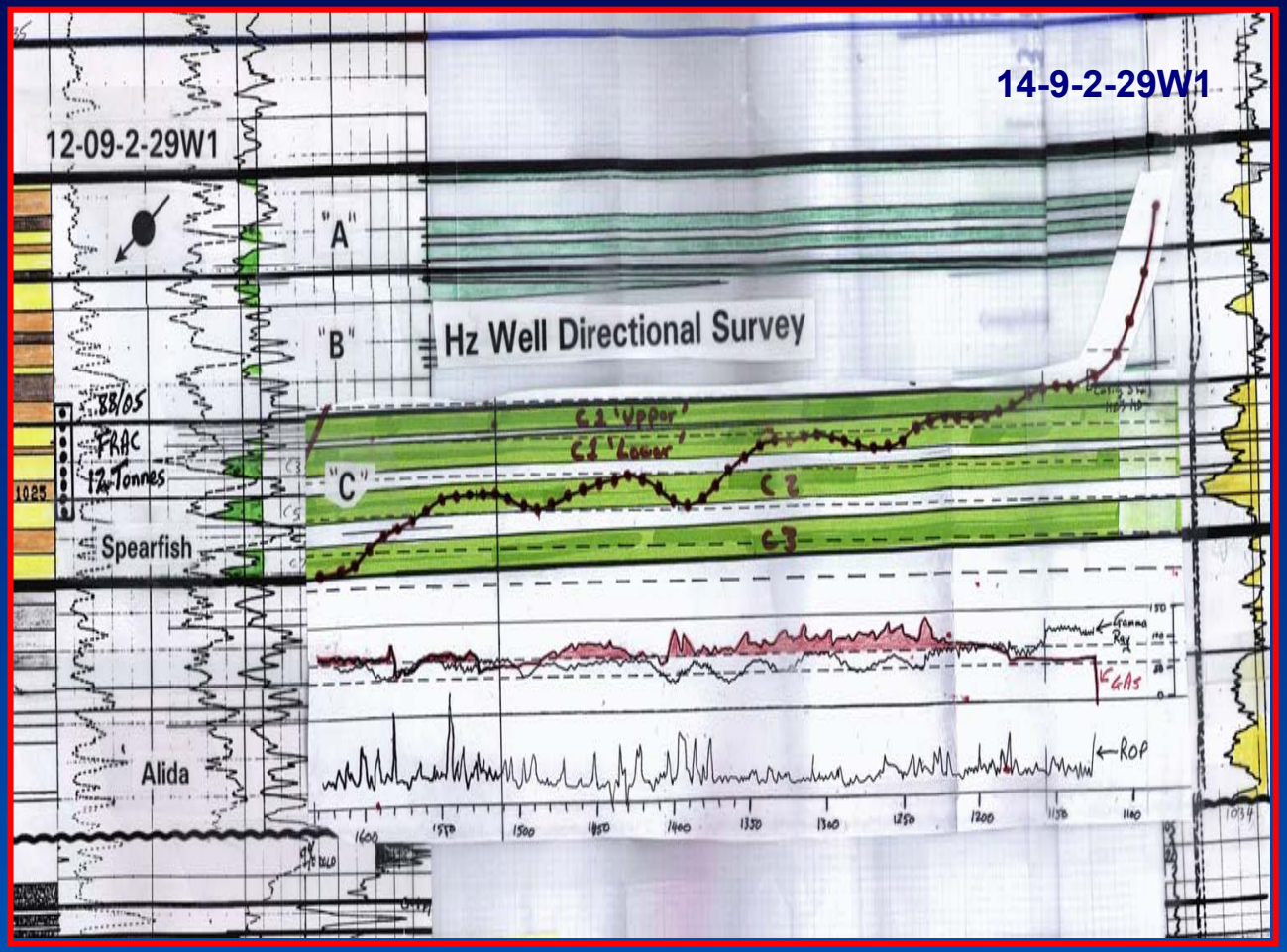
Fracture Pressure Gradient	0.667	Psi/ft
Fracture (Parting) Pressure	2,253	Psi
	15,537	KPa

Note:

Overburden gradient is 1.0 Psi/ft

PMG

Hz Well Trajectory



- Wellbore penetrated each sand lense
- Gamma ray (red) indicated over 90% of Hz well length is effective
- Injectivity achieved 60 to 80 m^3/d

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Monitoring of Injection Conformance

Problems:

- Injection profile in multi-layered or several perforating intervals
- Presence of thief zones
- Fracing into adjacent zones
- Behind casing channelling

Diagnoses:

- Production logging tool (PLT)
- Temperature survey
- Spectral Noise Logs (SNL)

TGT

P
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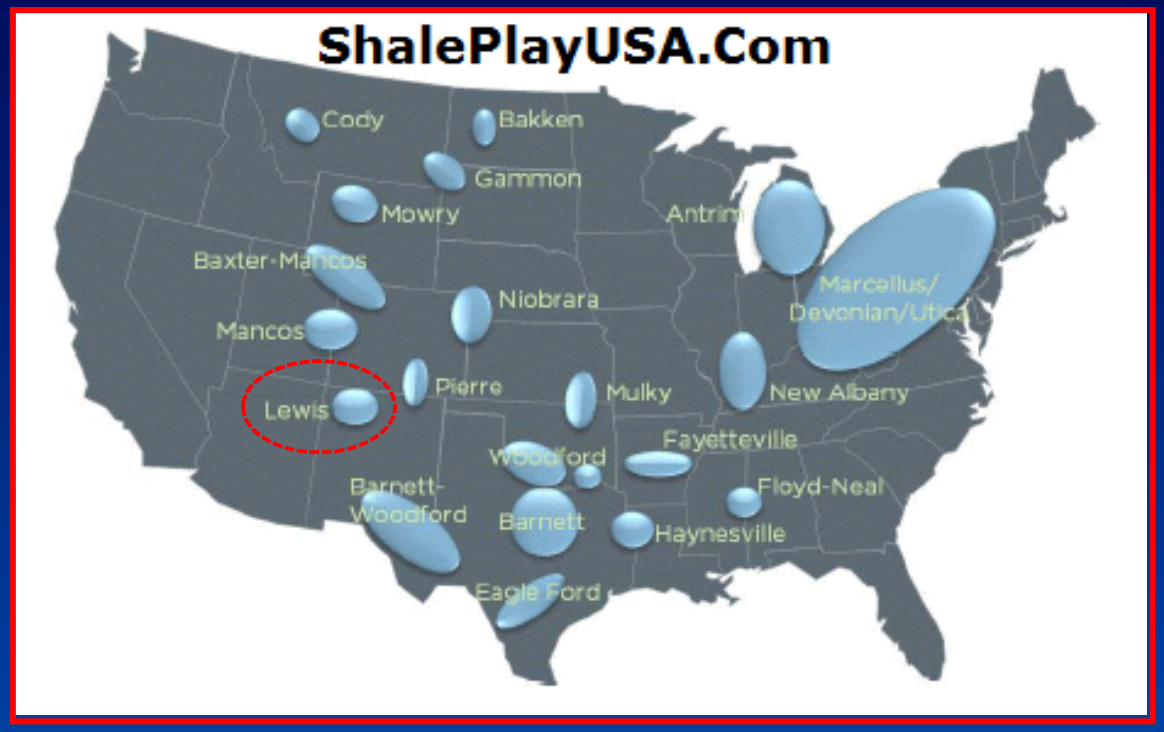
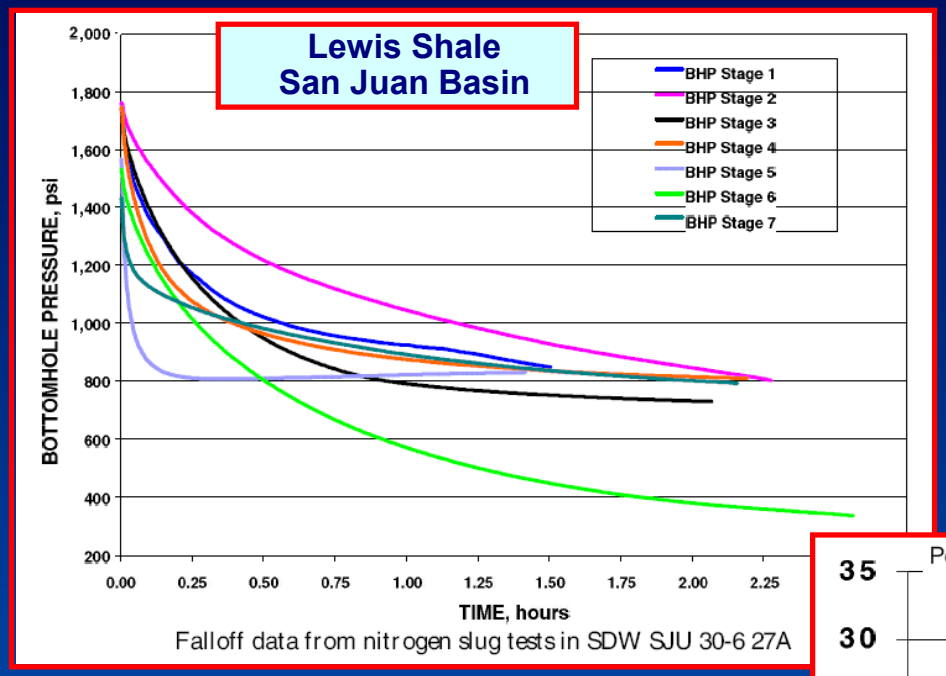
Injection Testing for Shale Formations



- Traditional well testing techniques are unrealistic for unconventional reservoirs (it requires very long tests)
- Diagnostic Fracture Injection tests (DFIT)
- Nitrogen injection/fall-off tests

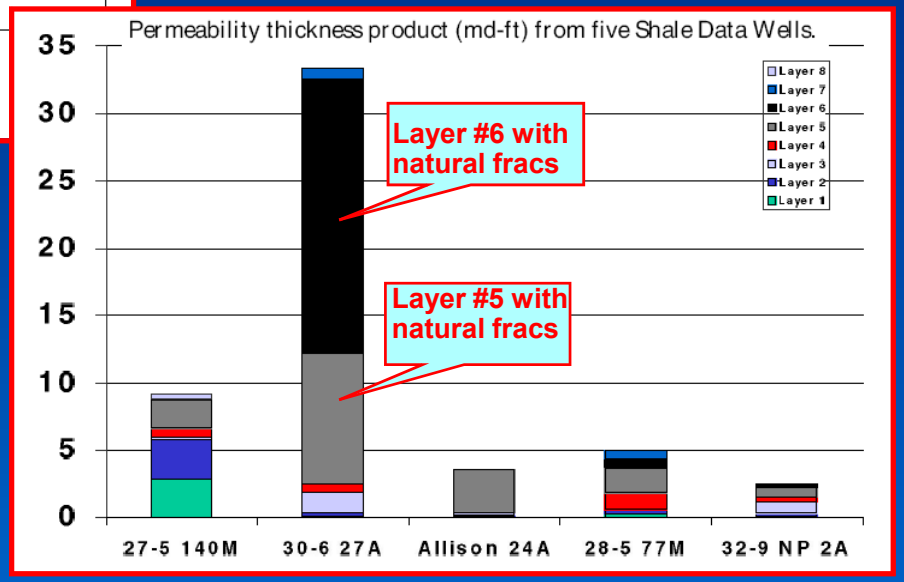
PMG

N_2 Injectivity Fall-off Tests



Why N_2 injectivity Test?

- Water injectivity is very poor
- Flow/build-up requires long tests
- Expensive to test many intervals for CBM/shale



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Ref: SPE: 63091

Hall Plot

The Hall plot was introduced to the industry in 1963, to evaluate well injectivity problems, as a result of near wellbore condition changes which could happen due to:

- Wellbore damage or plugging
- Well stimulation, such as acidizing or fracing (intentional)
- Formation fracturing (non-intentional !)
- Water leakage; behind the casing

Ref: SPE# 30774, by H.N. Hall (1963)

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Hall Plot

Applications of the Hall Plot:

- Identify injectivity problems, using trends of injection history data (injection volumes and injection wellhead pressure)
- Quantify wellbore skin factor without interrupting injection operations or conducting any costly well testing !

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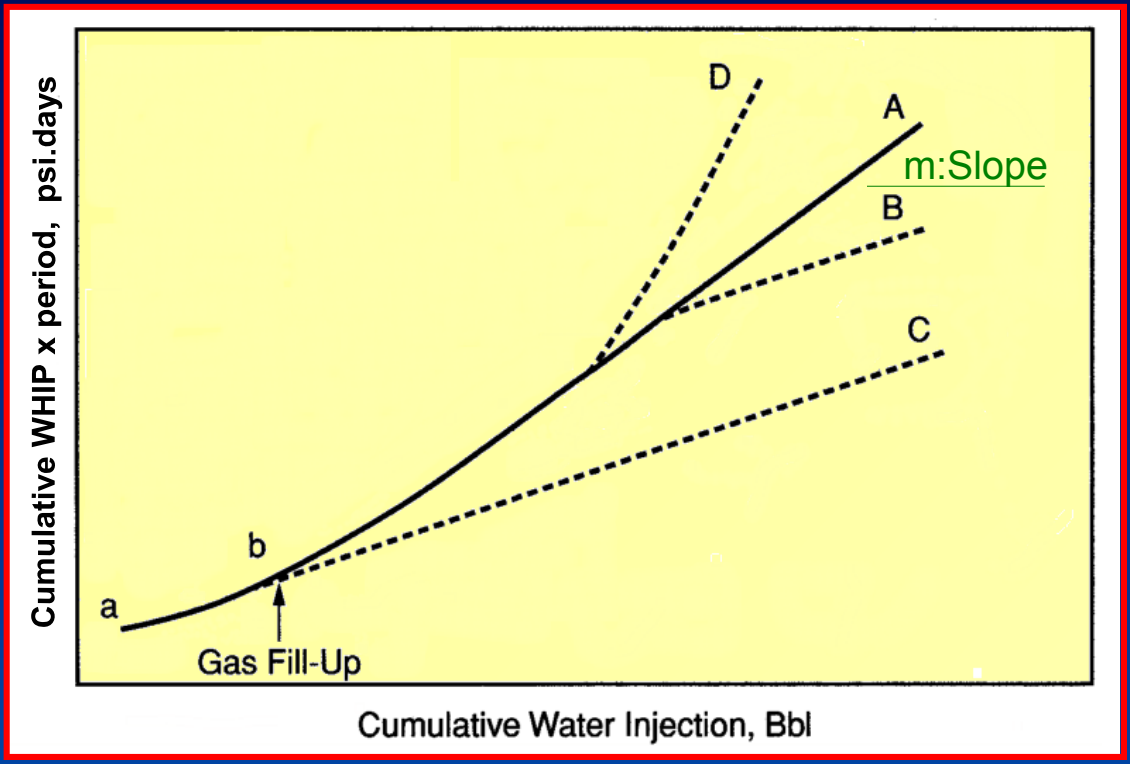
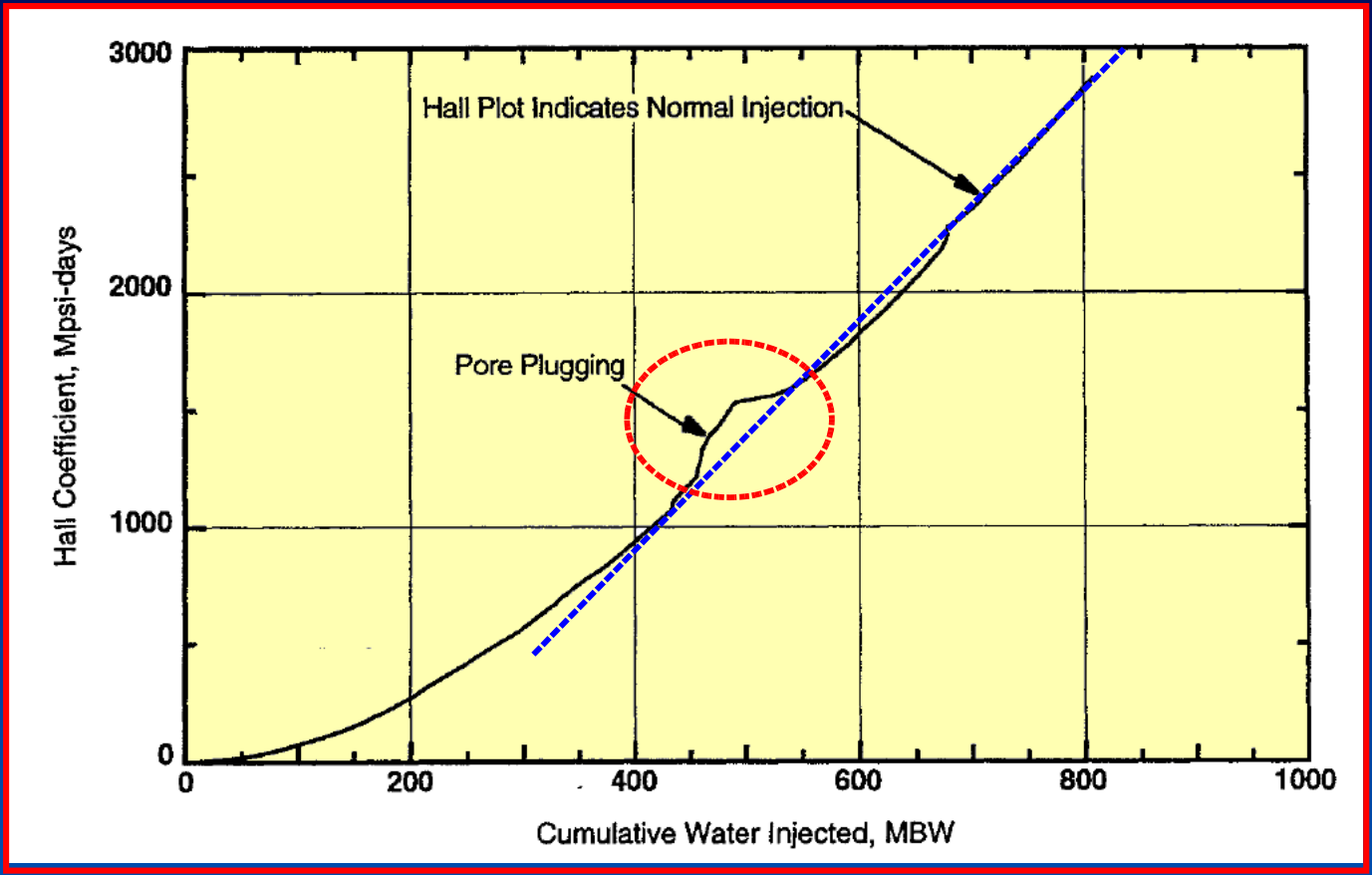
Hall Plot

The slope of the straight line “m” can be used to determine the skin factor



- a - b : Gas fill-up
- **Curve “A”:** Normal operation (no change in injectivity)
- **Curve “D”:** Deterioration in wellbore condition
- **Curve “B”:** Improvement in wellbore condition (stimulated)
- **Curve “C”:** Injection water channelling to a different zone

Temporary Plugging



Changes in the slope of the Hall Plot typically occur gradually, so several months (6 or more) of injection history may be needed to reach reliable conclusions about injection behaviour . This the temporary anomaly (deviation from the straight line) is due to plugging that disappeared in short time.

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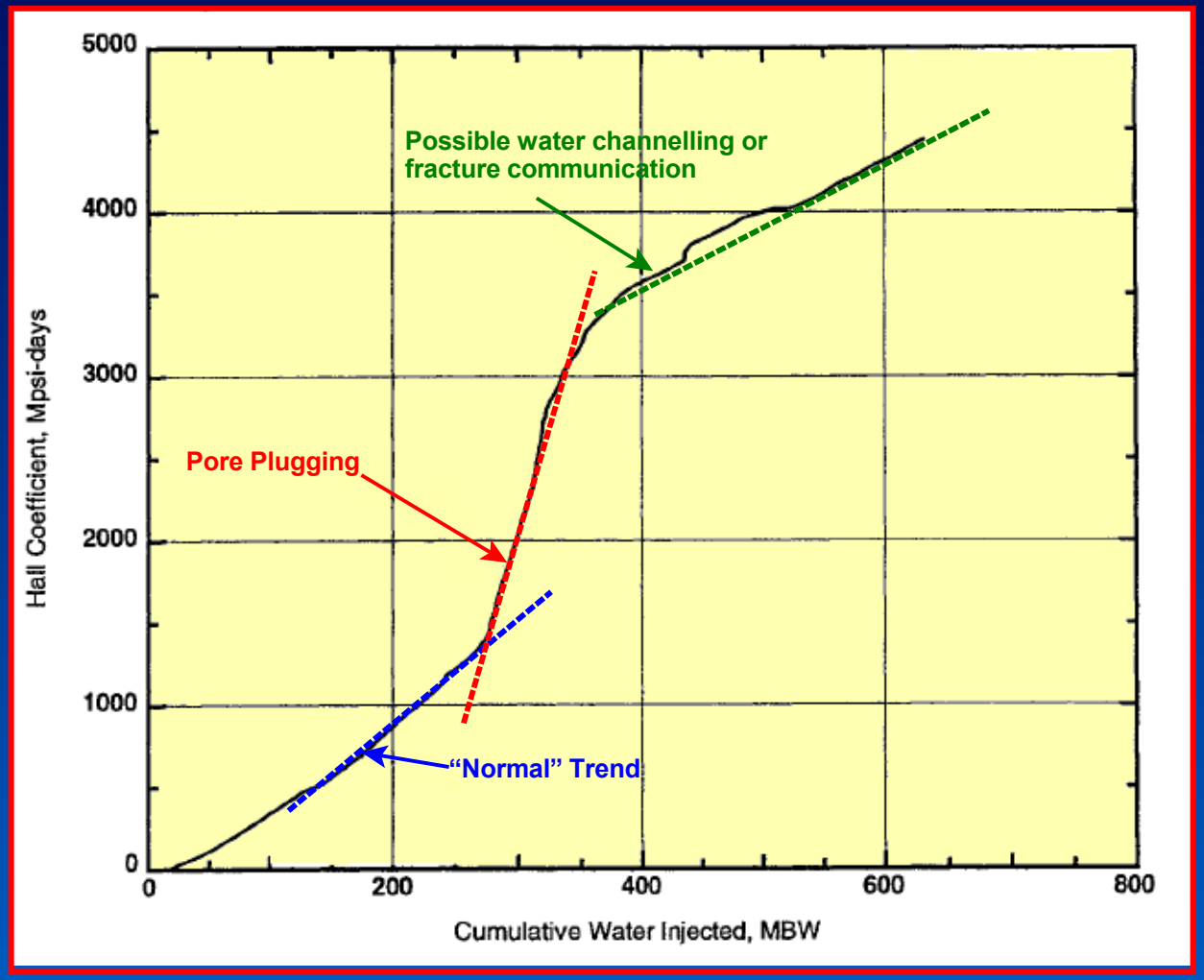
Detection of Operational Problems



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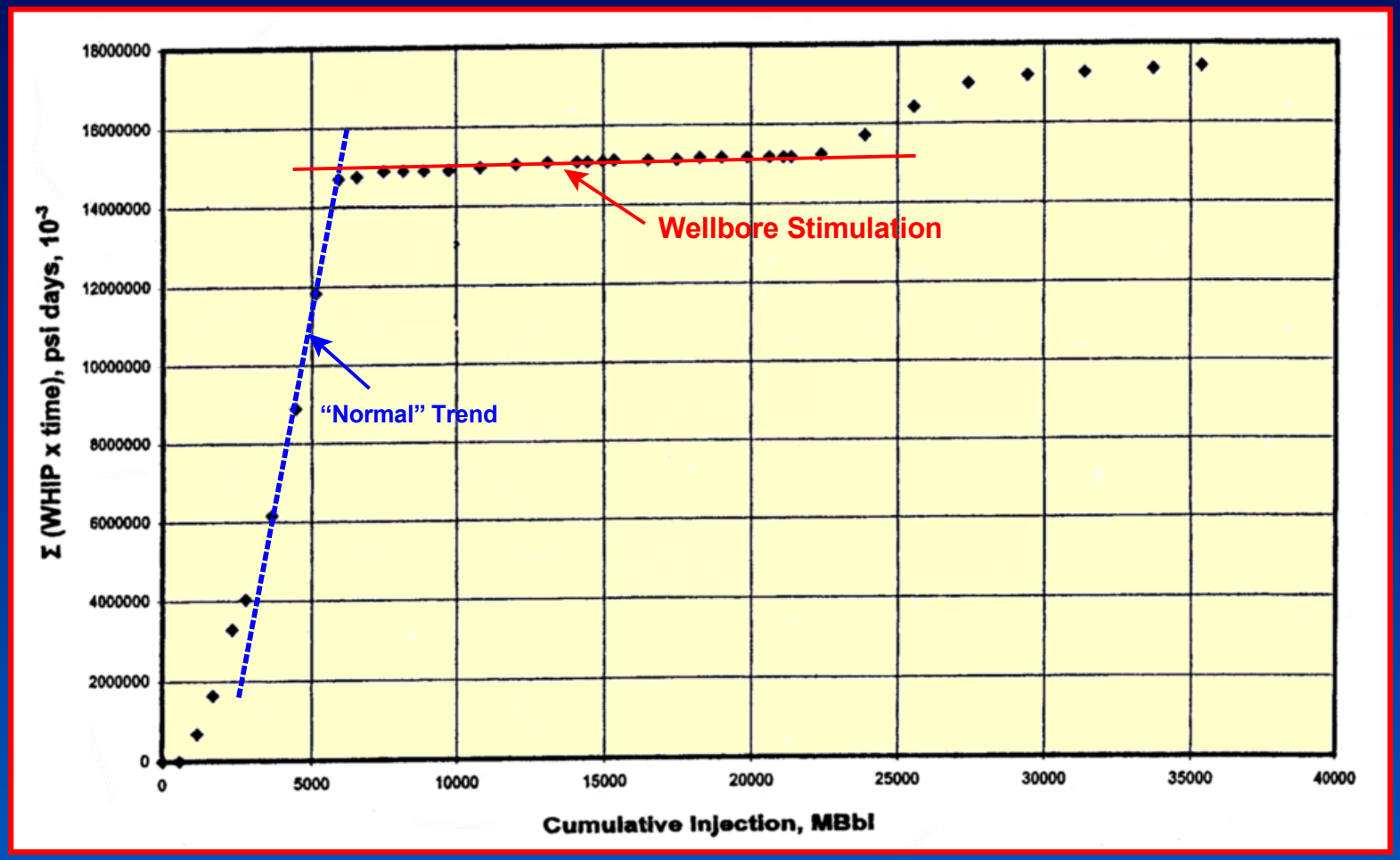
Well Stimulation of Fracturing



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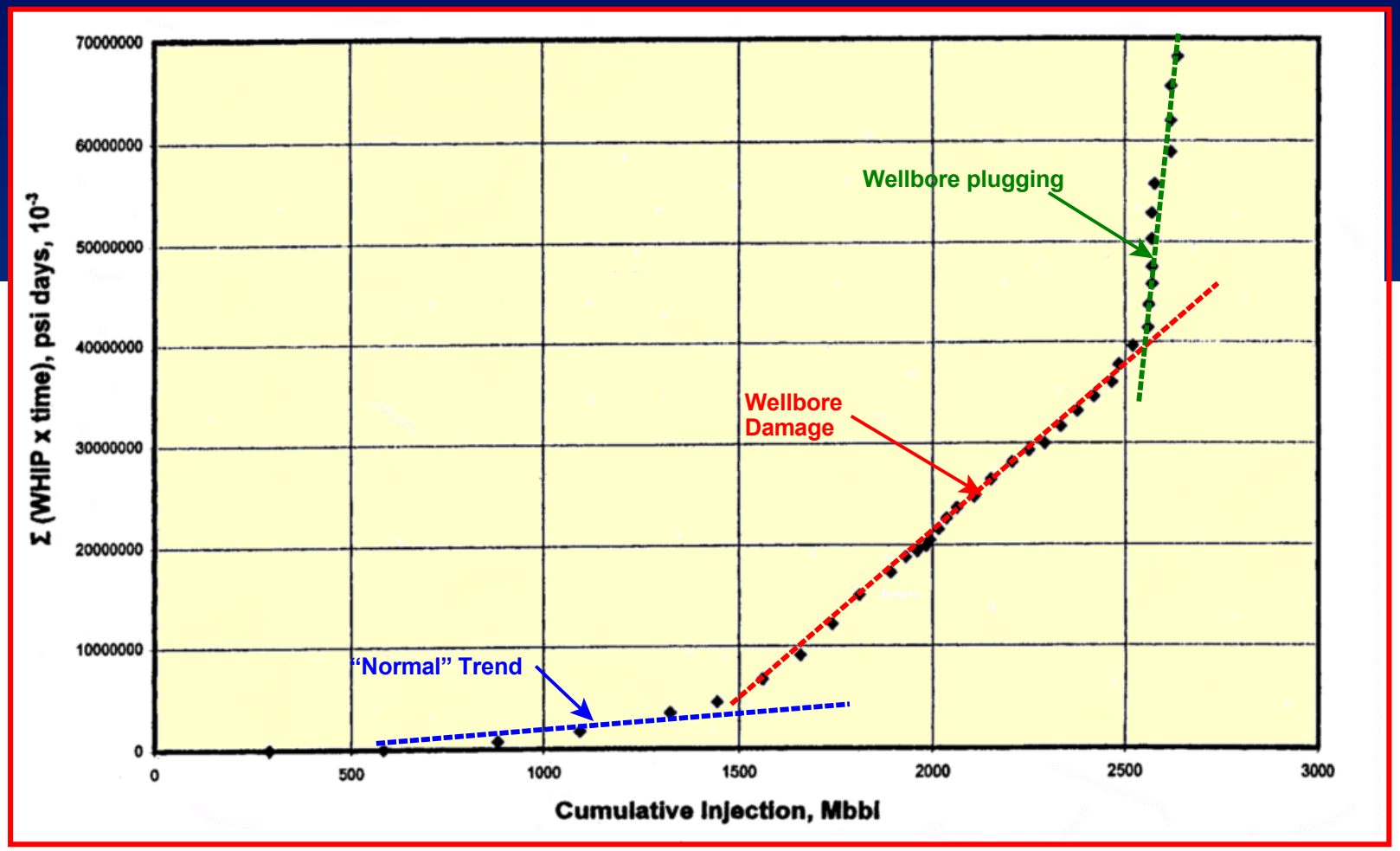
Increasing Wellbore Damage



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Hall Plot

The change in the skin factor is estimated from the change in the slope of the Hall Plot straight line trends

$$S_2 = S_1 + \frac{k\ h}{141.2\ \mu}\ (m_2 - m_1)$$

Where:

m_2:	Slope of the Hall Plot 2nd straight line (most recent data)	psi.days/Bbl
m_1:	Slope of the Hall Plot 1st straight line (initial data)	psi.days/Bbl
S_2:	Skin factor at current conditions	
S_1:	Skin factor at initial conditions	

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Diagnostic Fracture Injection Test (DFIT) (Mini Frac)

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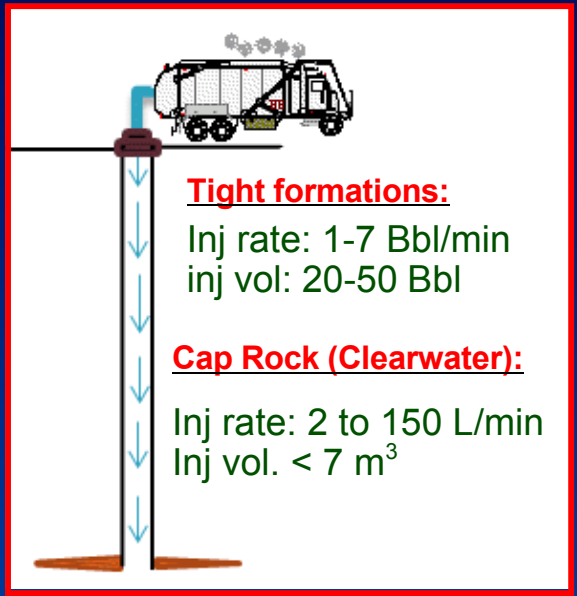
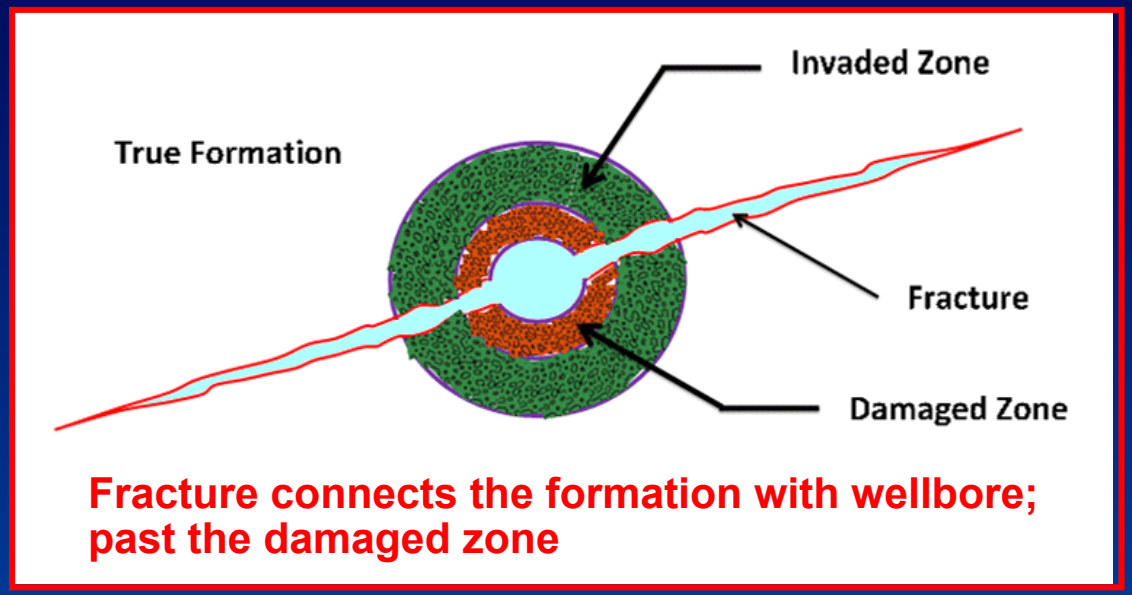
Mini Frac Test





- 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

PMG

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**
  - Pressure drop in perforation
  - Pressure drop as a result of well tortuosity

P
M
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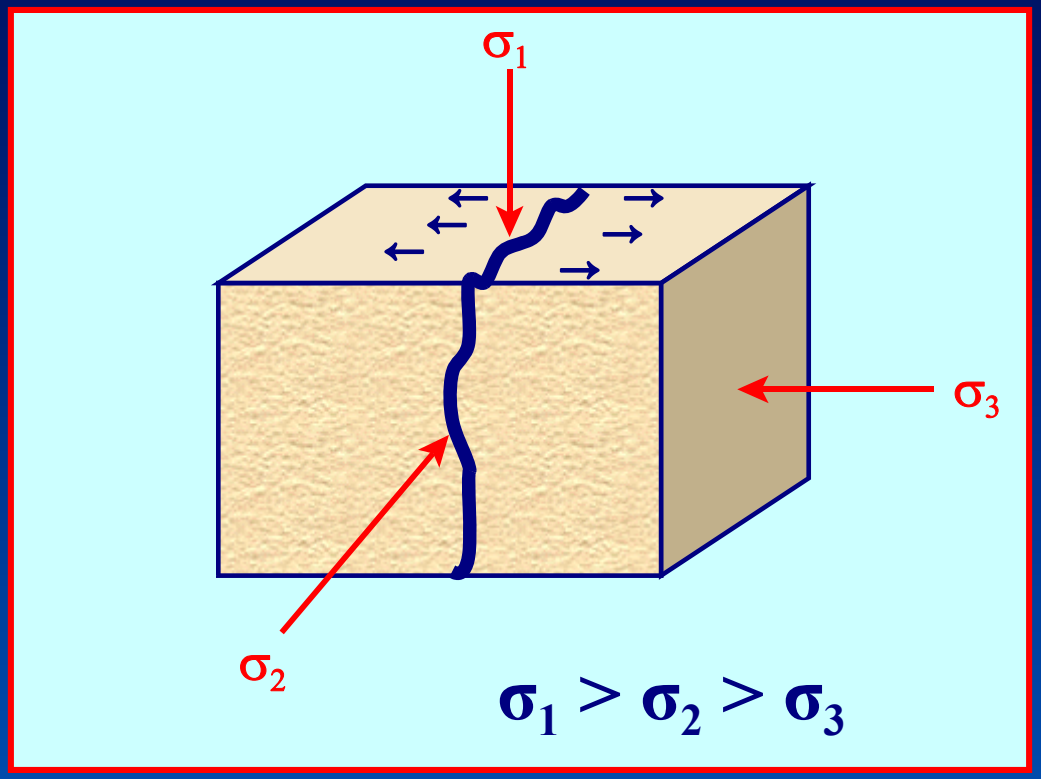
Fracture Orientation is Controlled by In- Situ Stress Field

Vertical fracture



Where:

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

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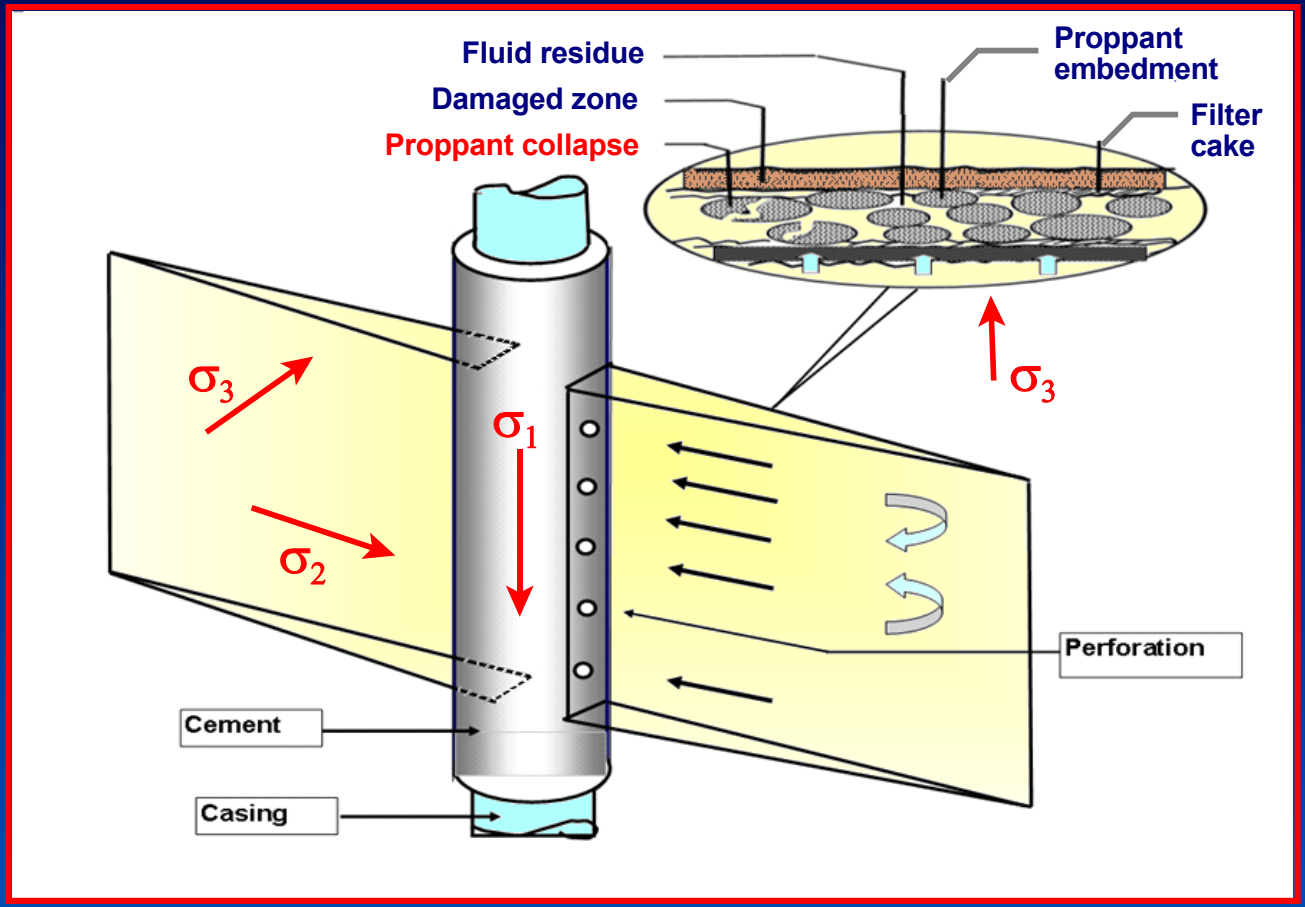
Why Minimum Stress (σ_3) is Important to Know?



Where:

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

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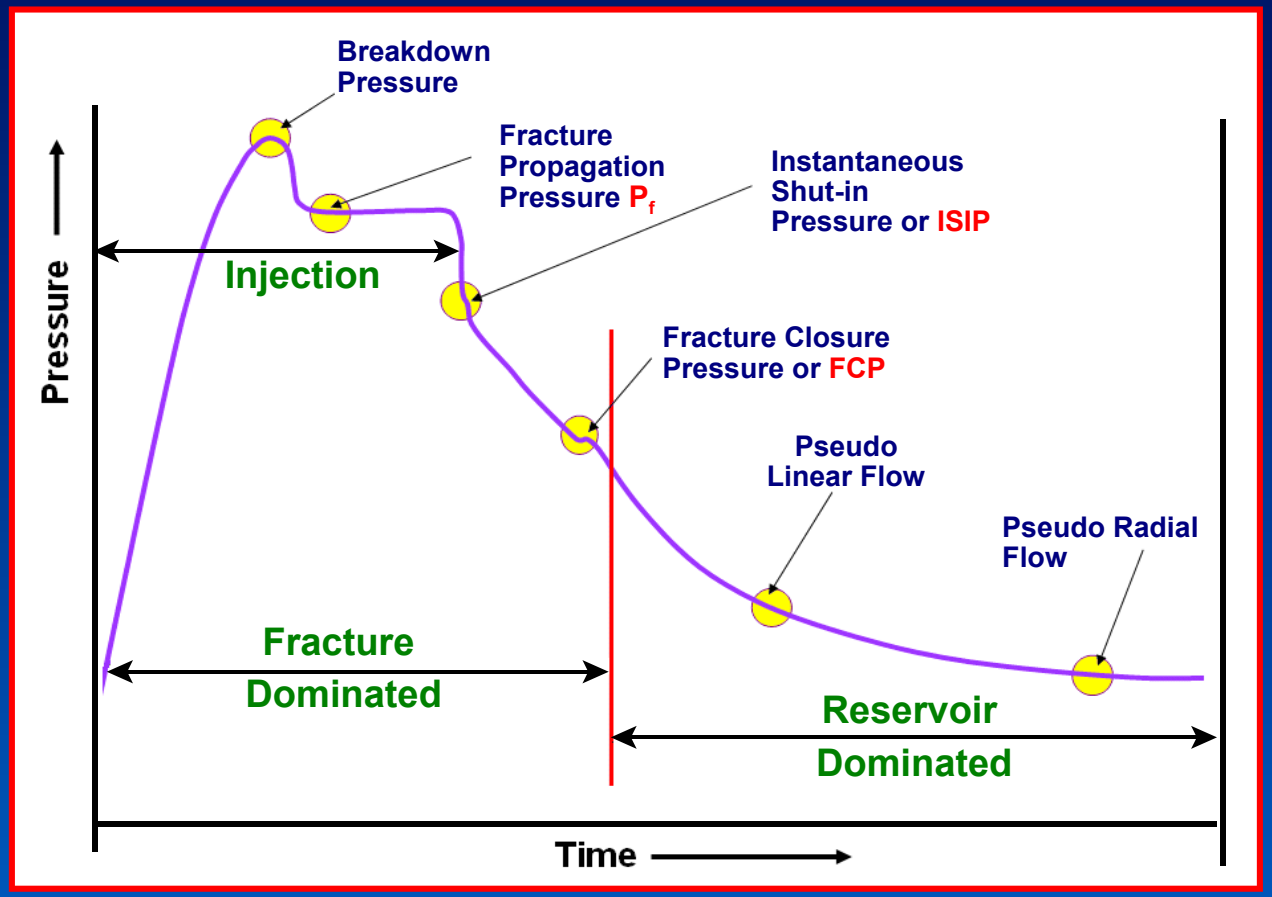
Mini Frac Typical Pressure Profile

Rule: $P_f > ISIP > P_c$



No flowback test

ISIP: the minimum pressure required to hold open a fracture

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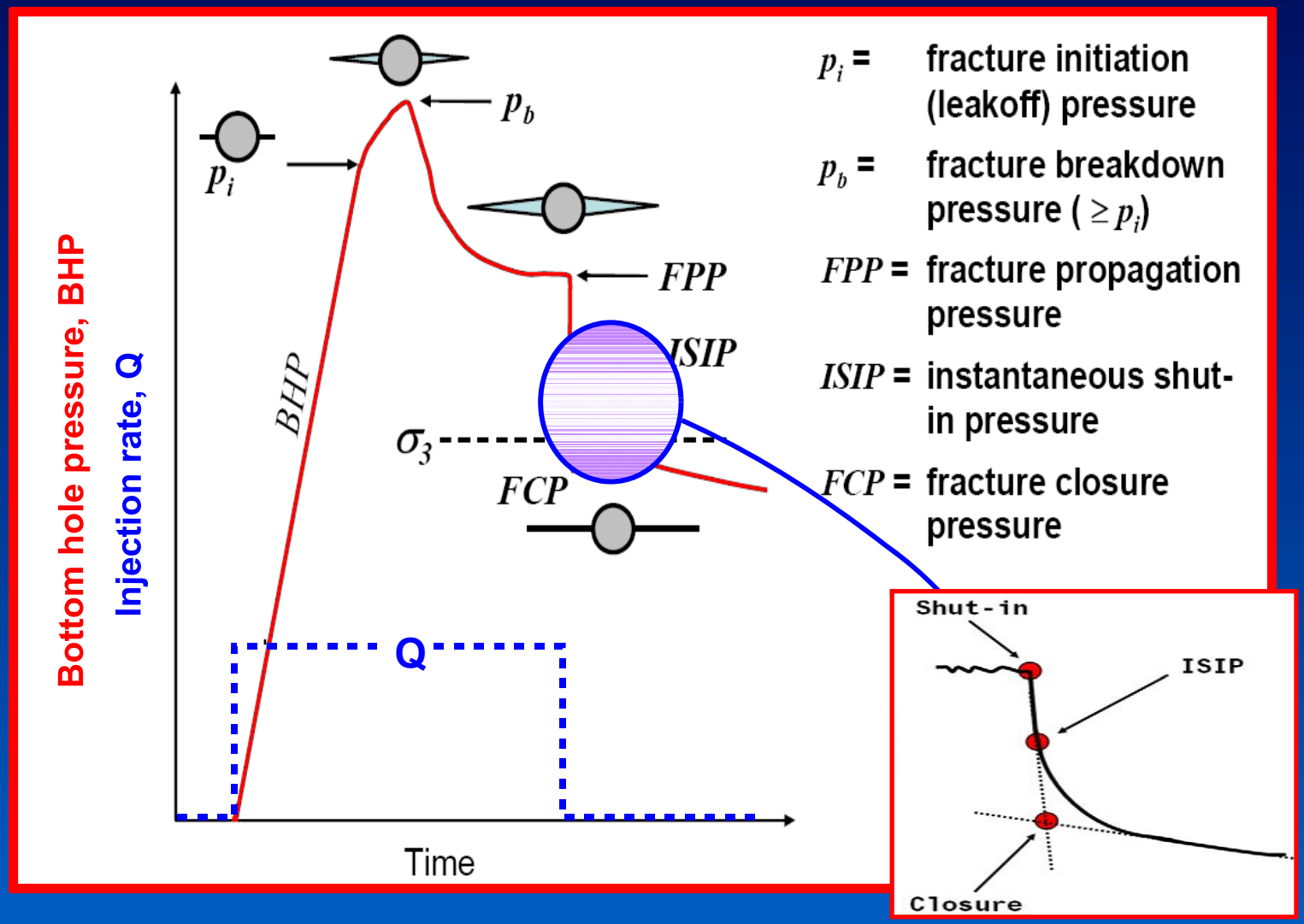
Fracture Dominated Analysis



ISIP: identified by significant Slope Change

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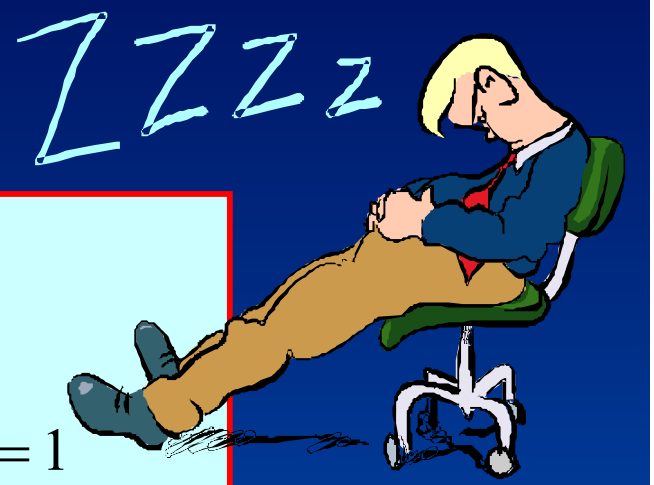
What is G-Function?

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

PMG

Pre-Closure Analysis

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

- Normal Leak-off
- Pressure dependent Leak-off (PDL)
- Fracture Tip Extension Leak-off
- Fracture Height Recession Leak-off

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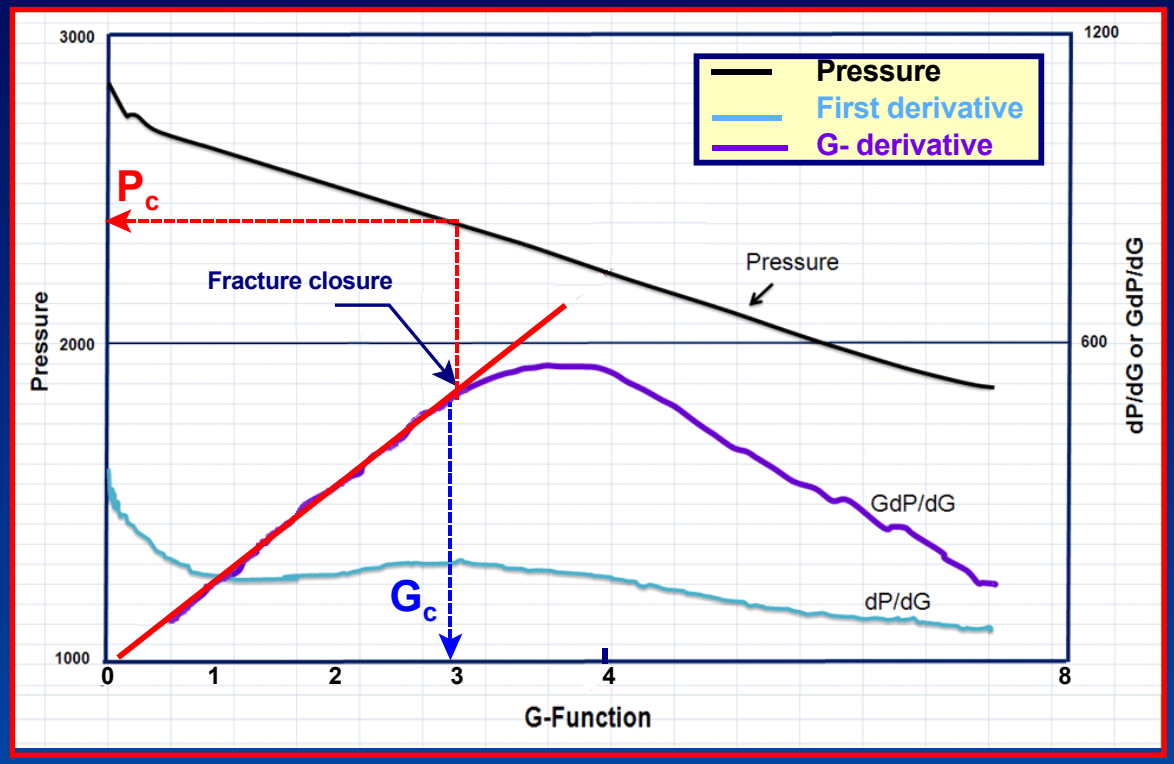
Normal Leak-off

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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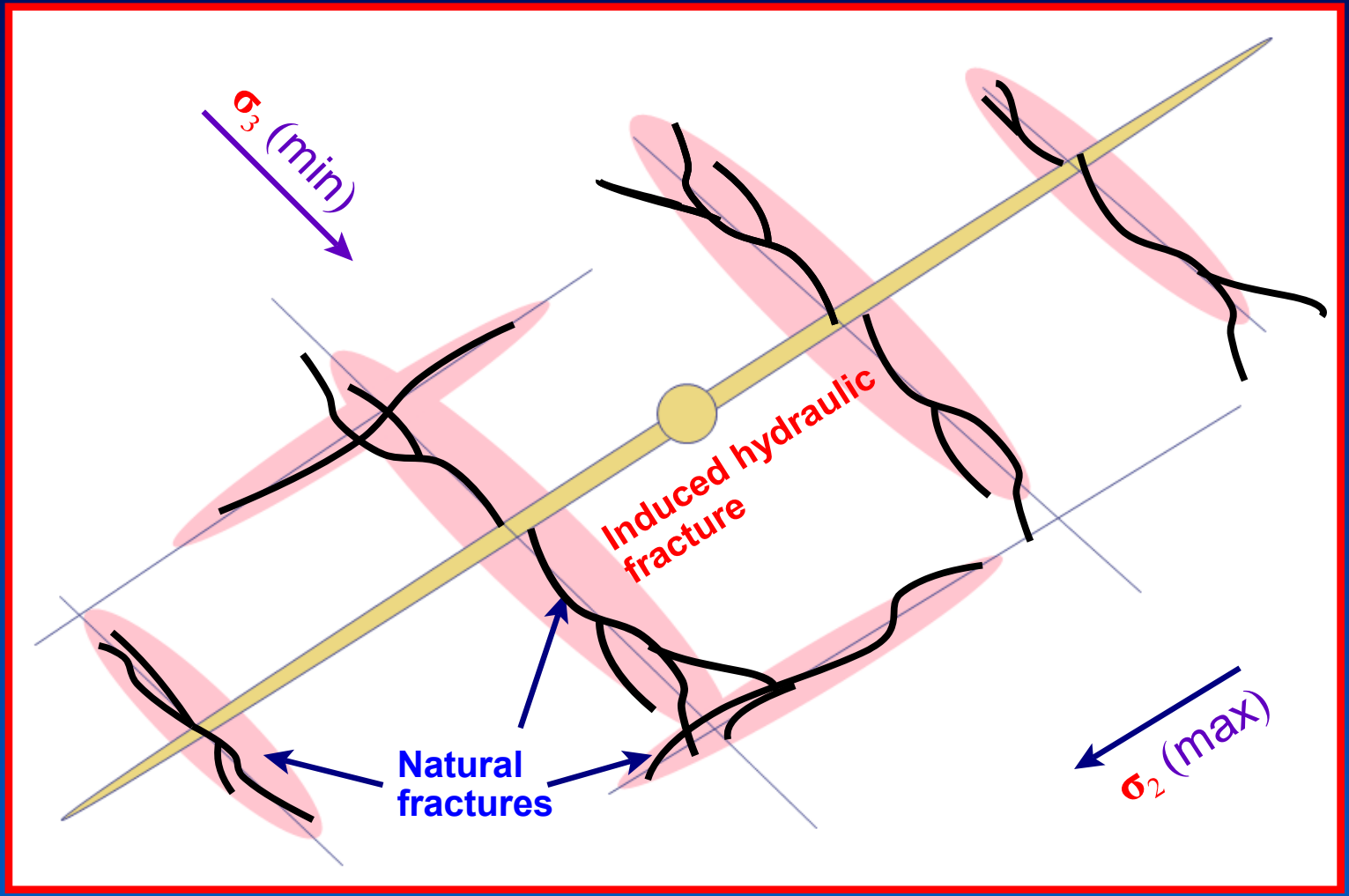
Pressure Dependent Leak-off (PDL)



P
M
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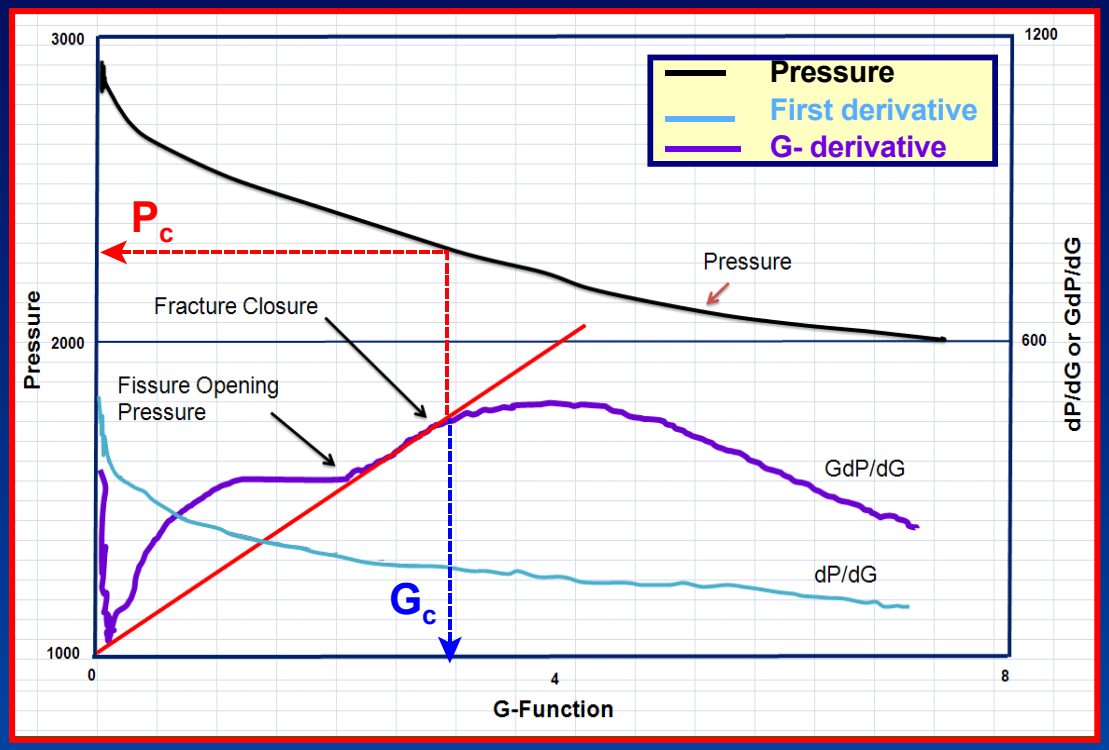
Pressure Dependent Leak-off (PDL)

When does it occur?

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



Characteristics:

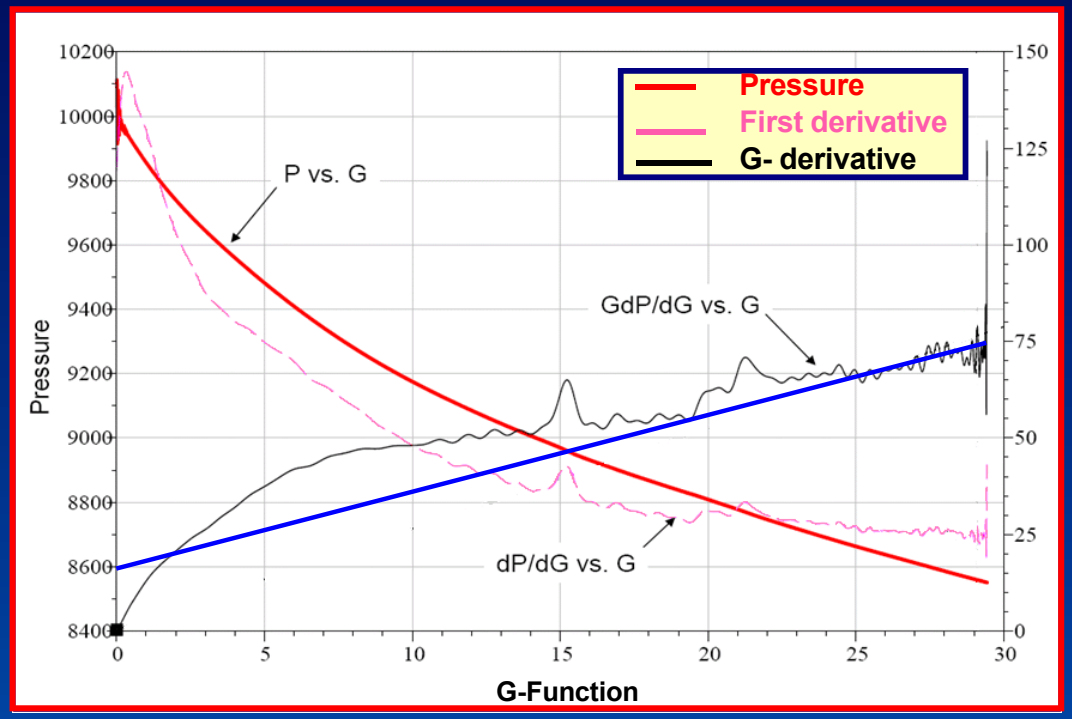
- G-Function shows a large hump above the straight line
- Subsequent to the hump, G-Function shows a normal leak off (linear trend)
- The end of the hump identifies the fissure opening pressure
- Deviation of G-Function from the straight line, determines fracture closure pressure (FCP)

PMG

Fracture Tip Extension Leak-off

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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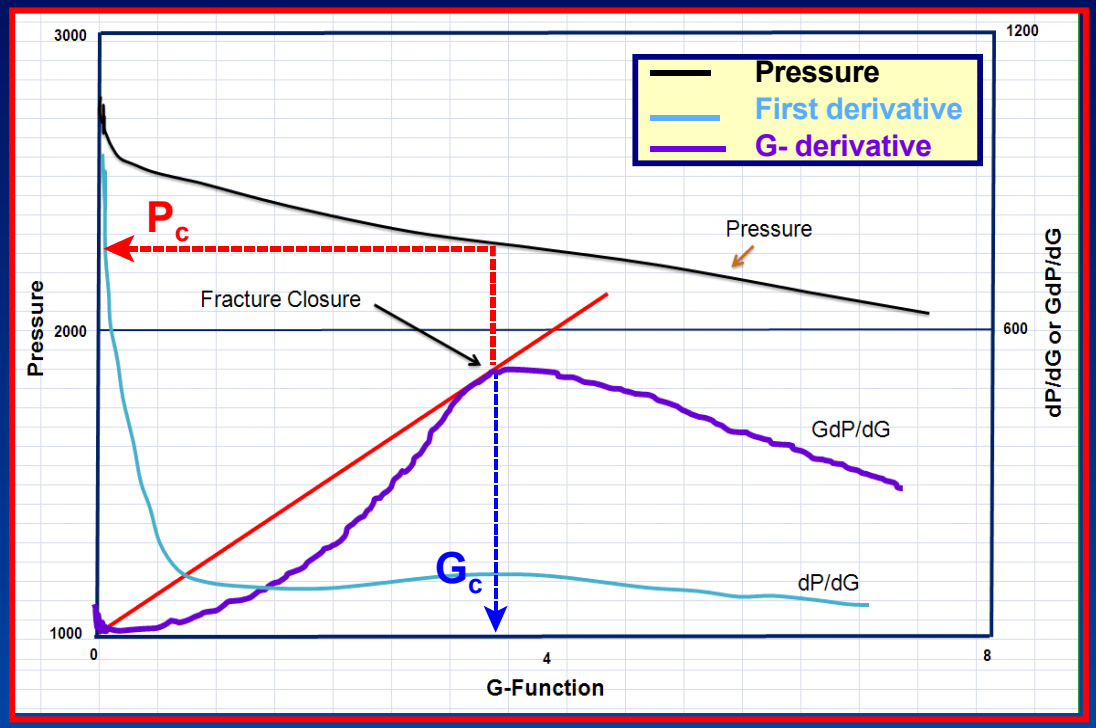
Fracture Height Recession Leak-off

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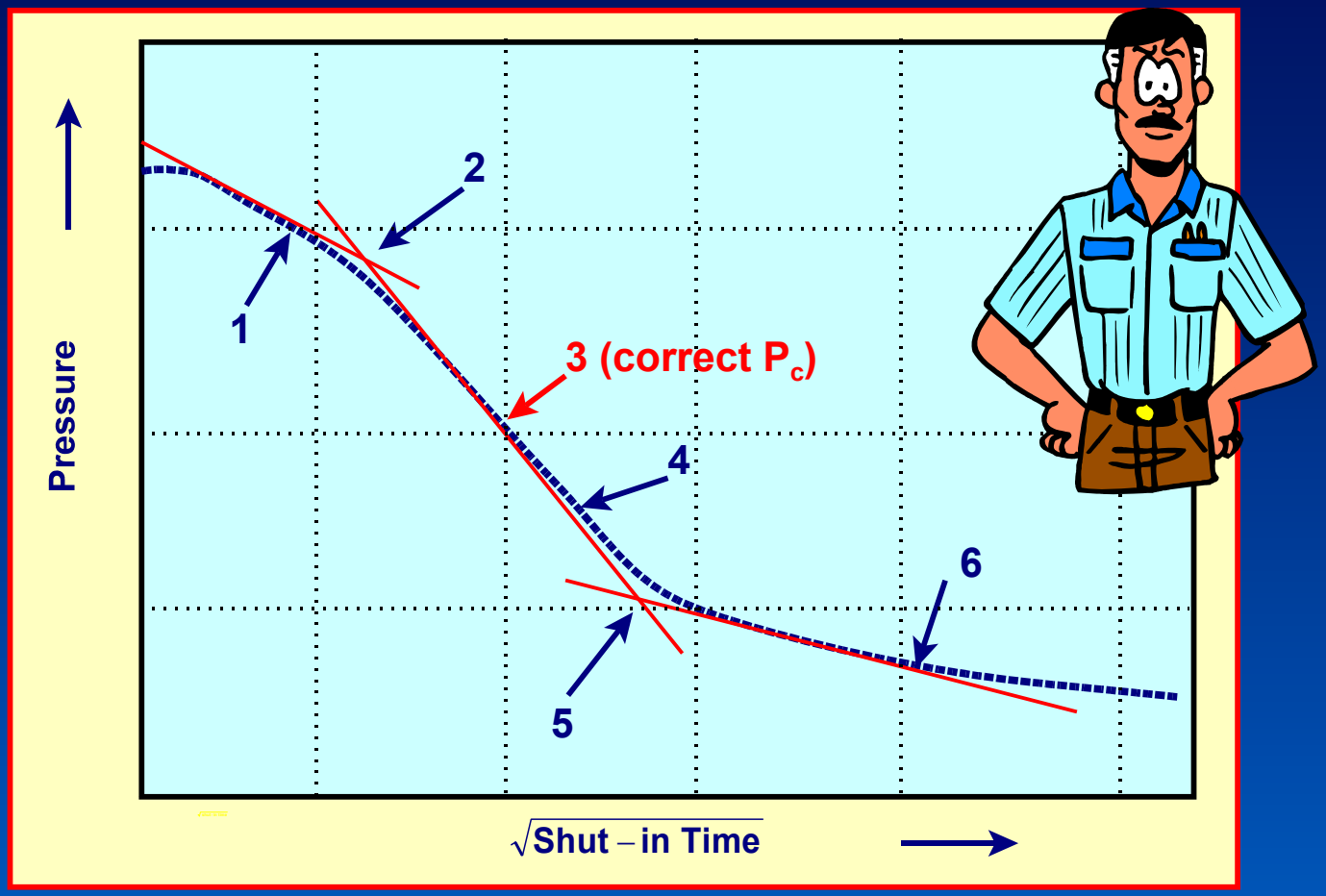
Use of Square Root of Time ($\sqrt{t}$) to Pick the Closure Pressure (P_c) ??



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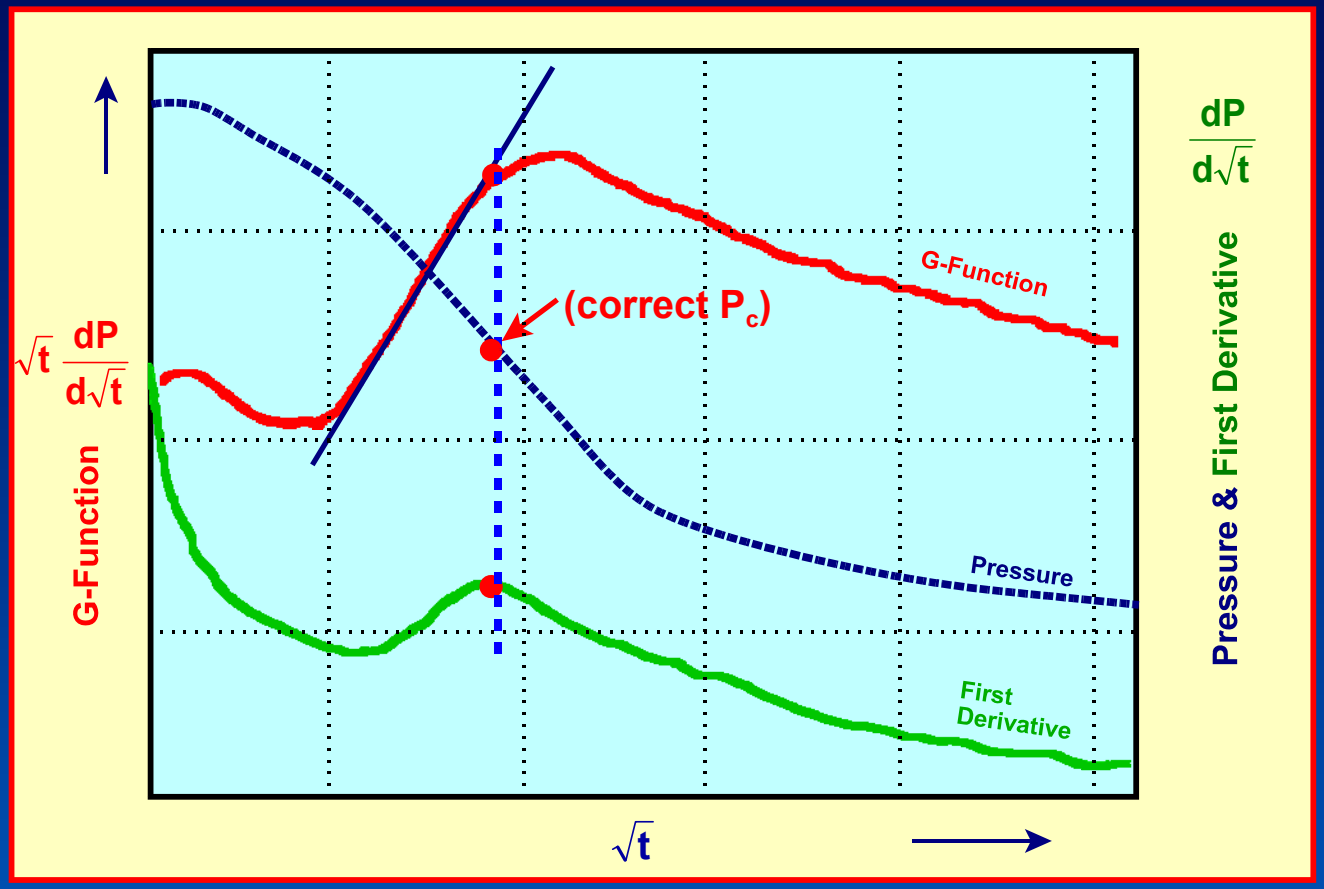
Use of Square-root of Shut-inTime Plot to Confirm Closure Pressure (P_c)



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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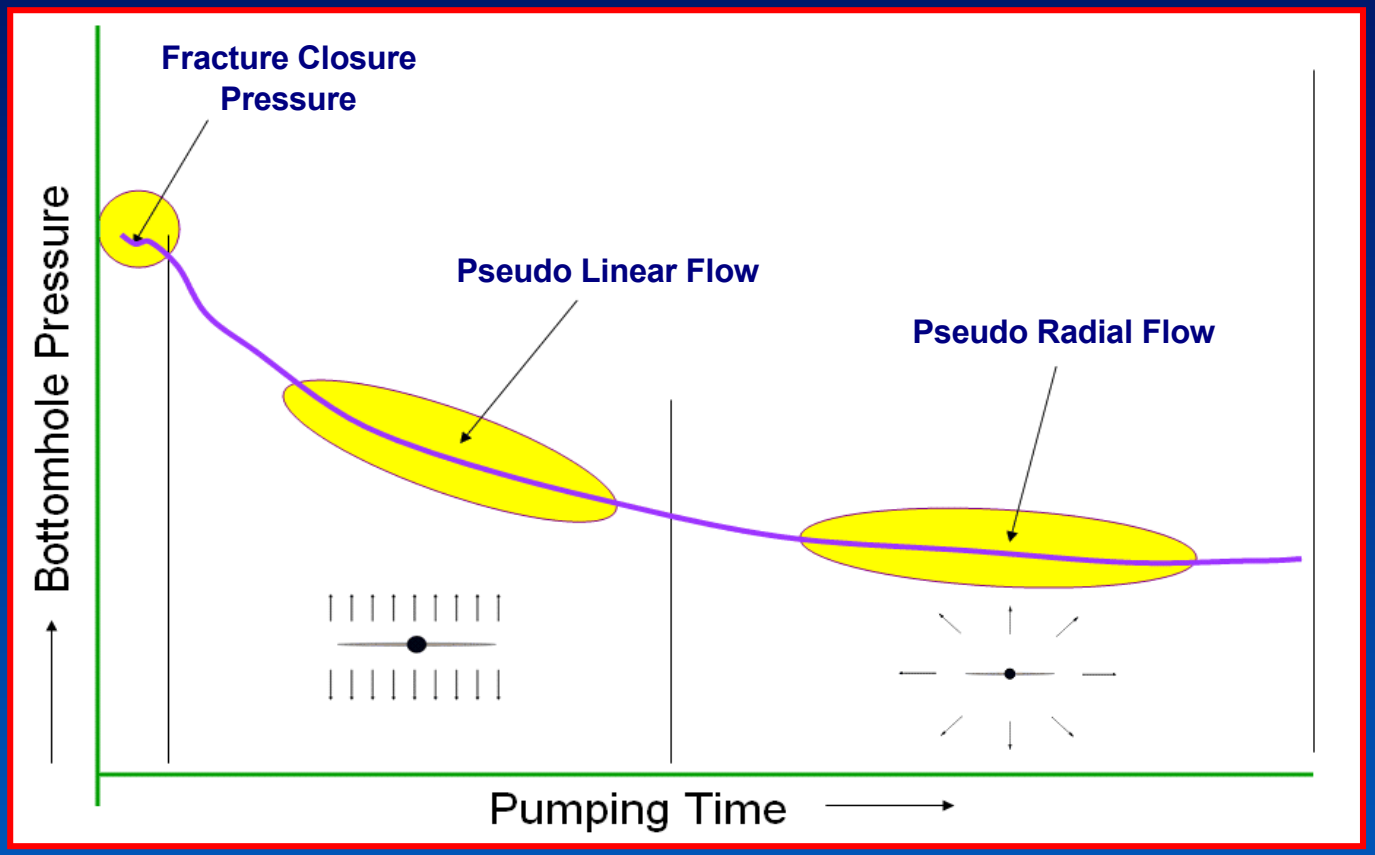
After Closure Analysis (ACA)

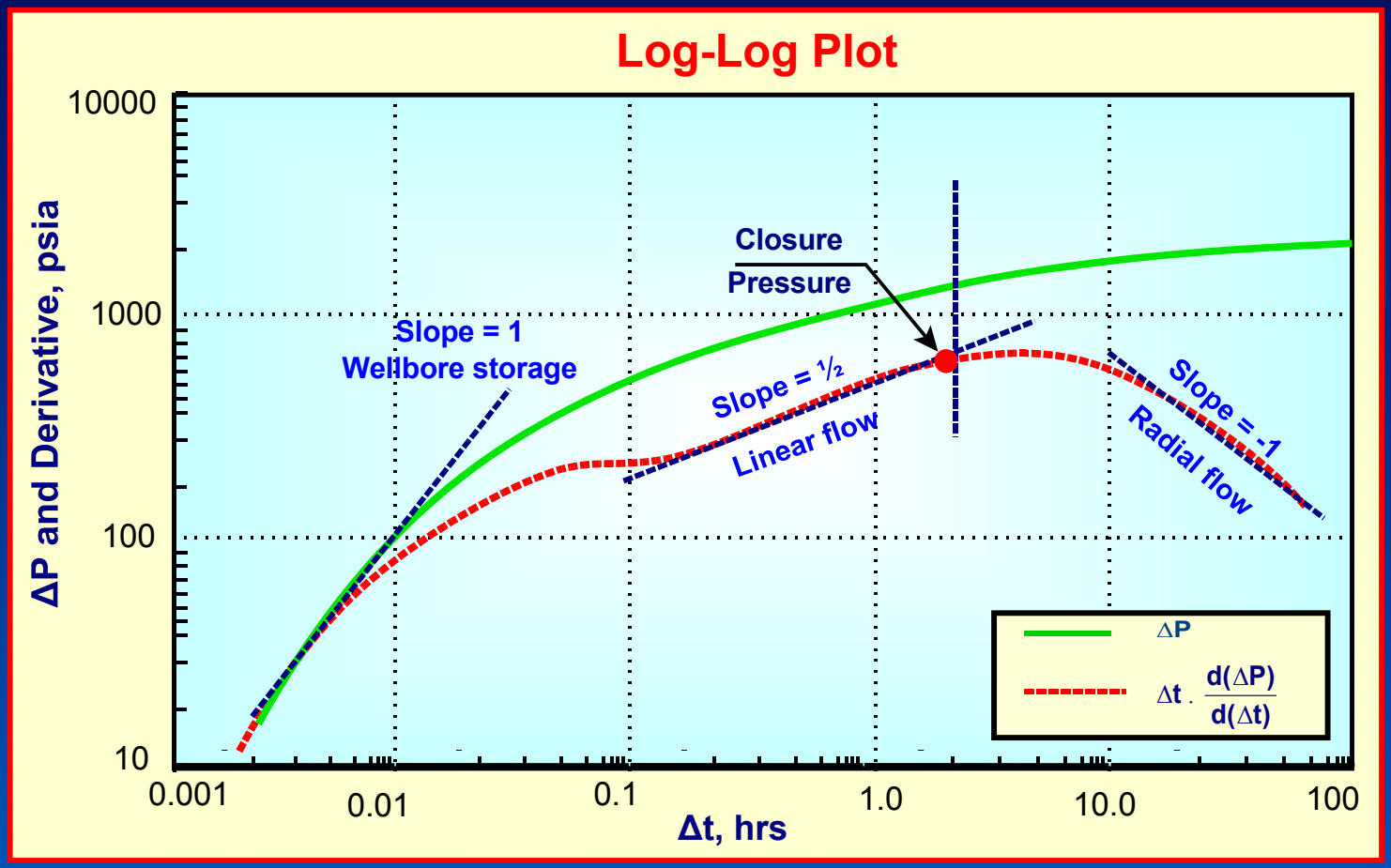
Reservoir Dominated Analysis:



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

PMG

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

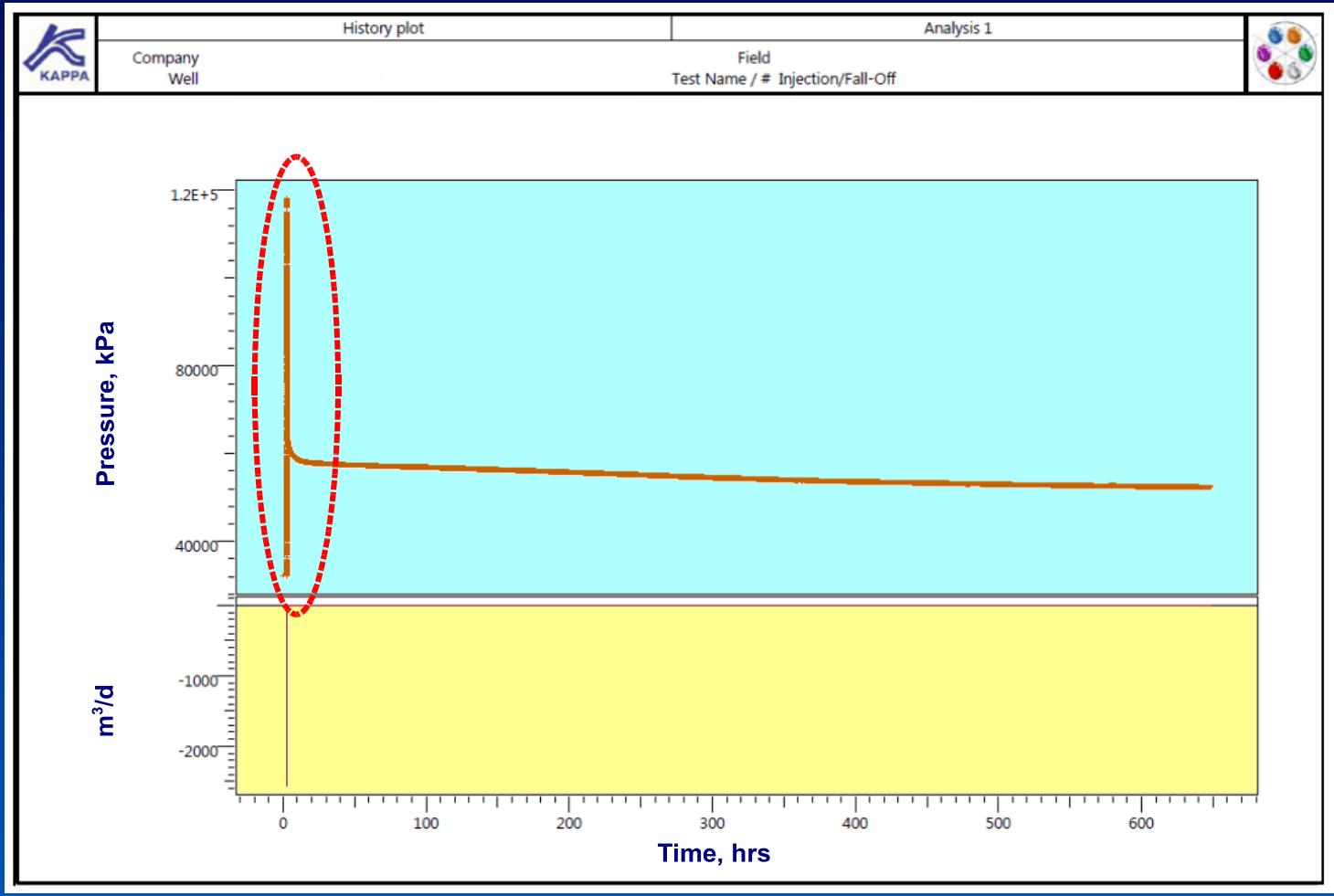
Case Study

Mini Frac
Duvernay Formation

Duvernay Ex

P
M
G

Test Raw Data



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

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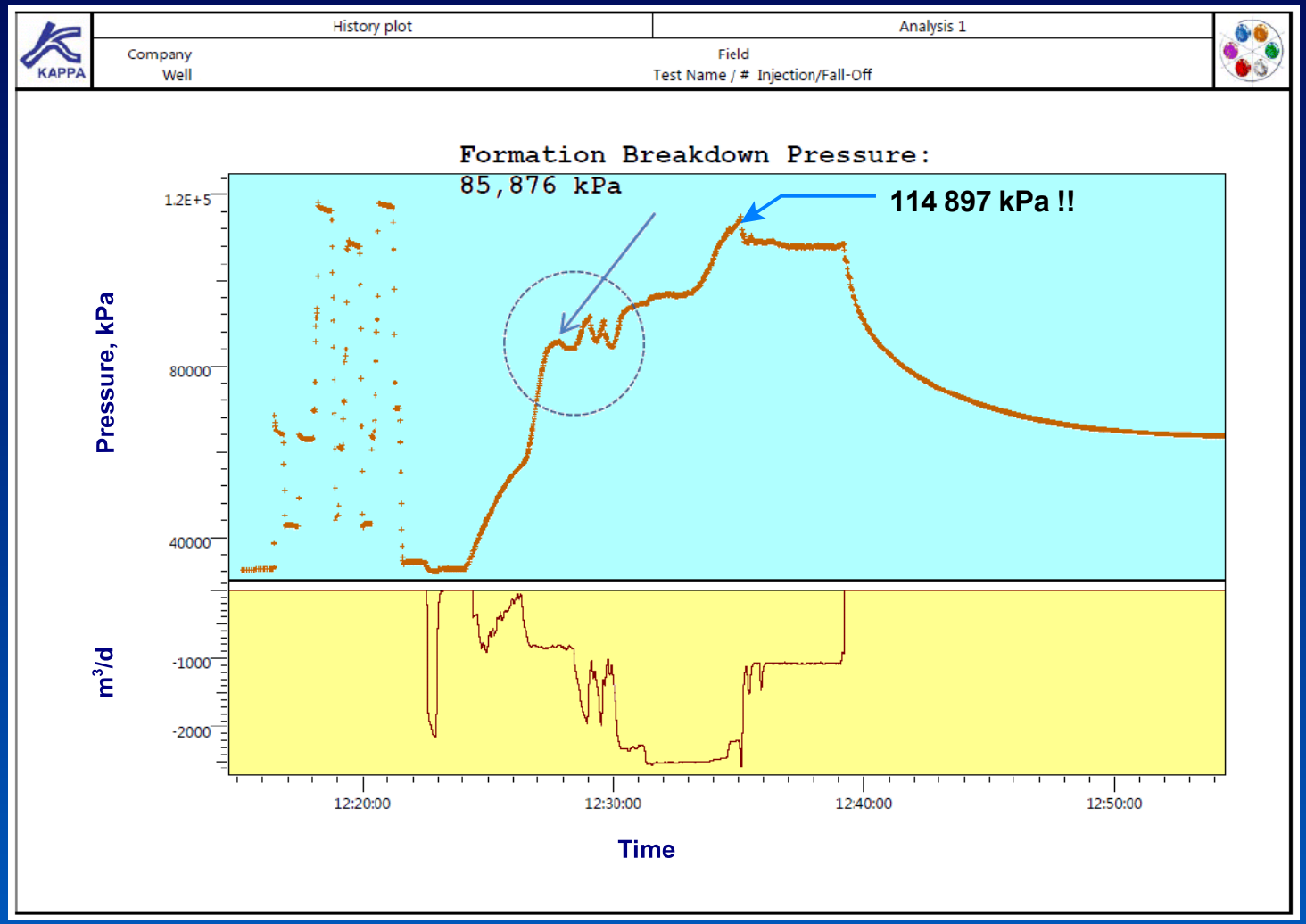
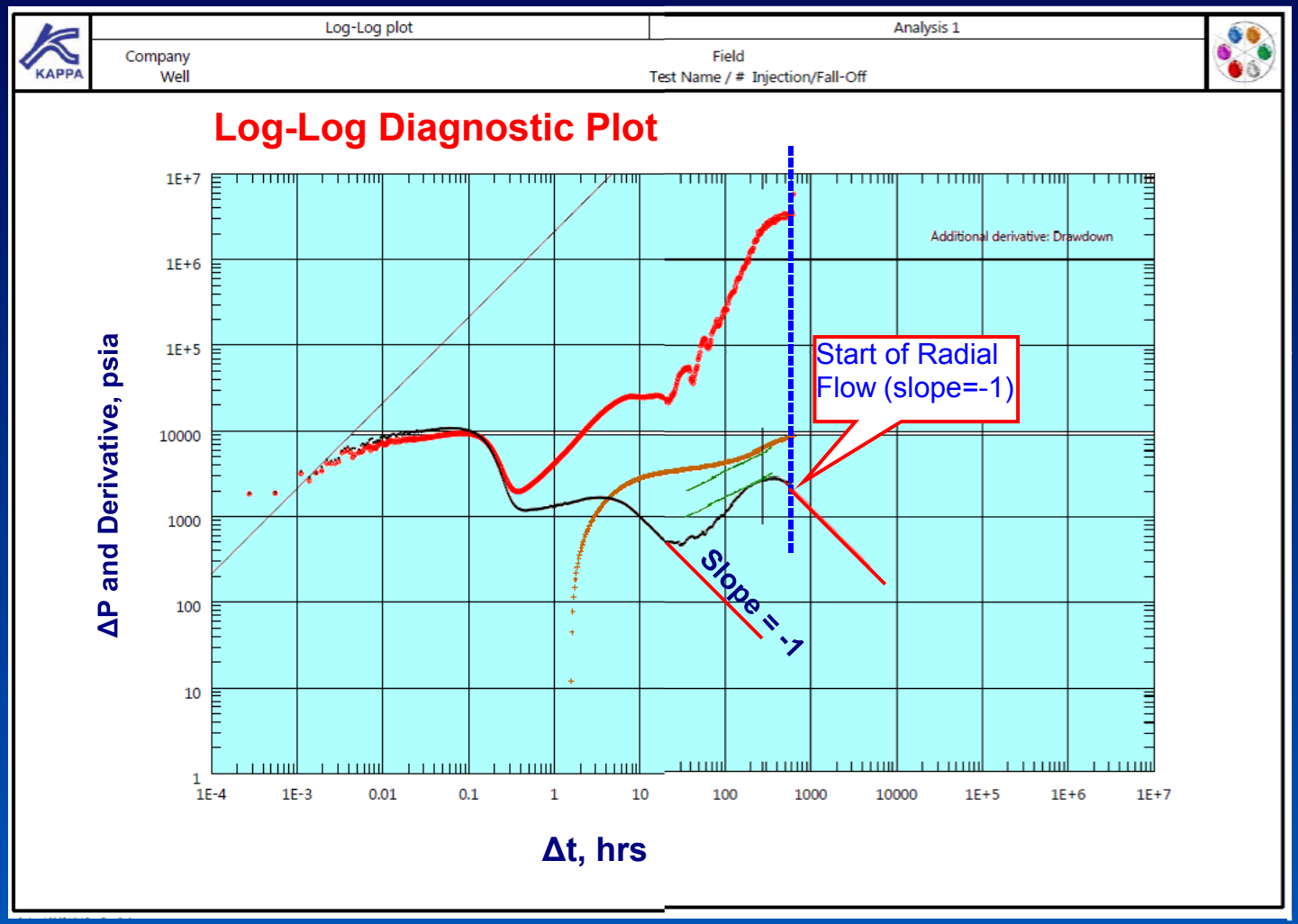
Injection Period



Injection pressure is too high, reaching114.9 mPa, and injection period as long as 15 minutes

PMG

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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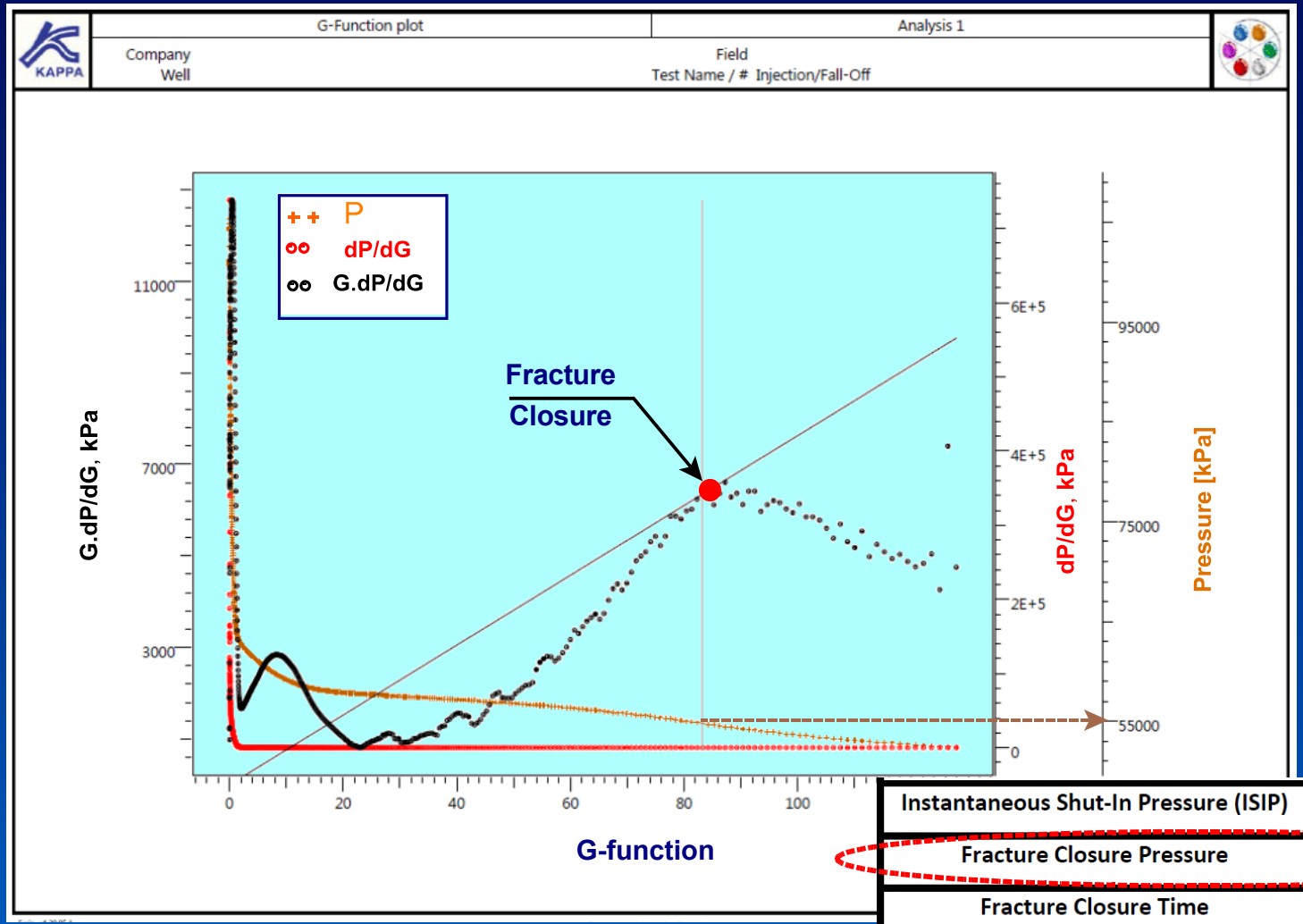
G-Function Plot

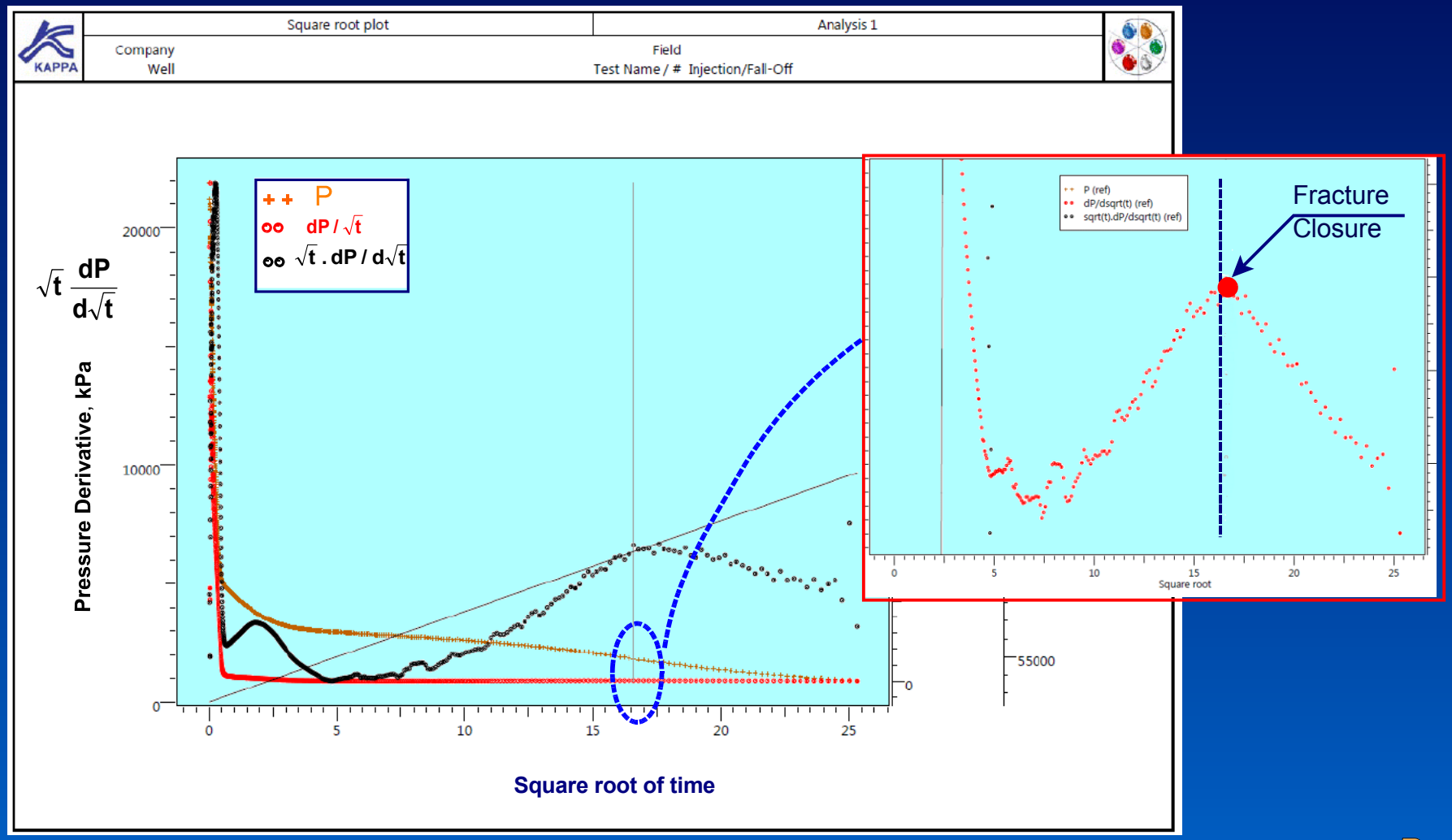


Instantaneous Shut-In Pressure (ISIP)	61,114.4	kPa
Fracture Closure Pressure	54,768.8	kPa
Fracture Closure Time	231.831	hr
Initial Reservoir Pressure	50,807.5	kPa
Closure G-value	83.1803	-

Frac height recession leakoff;
very high injection pressure was used

PMG

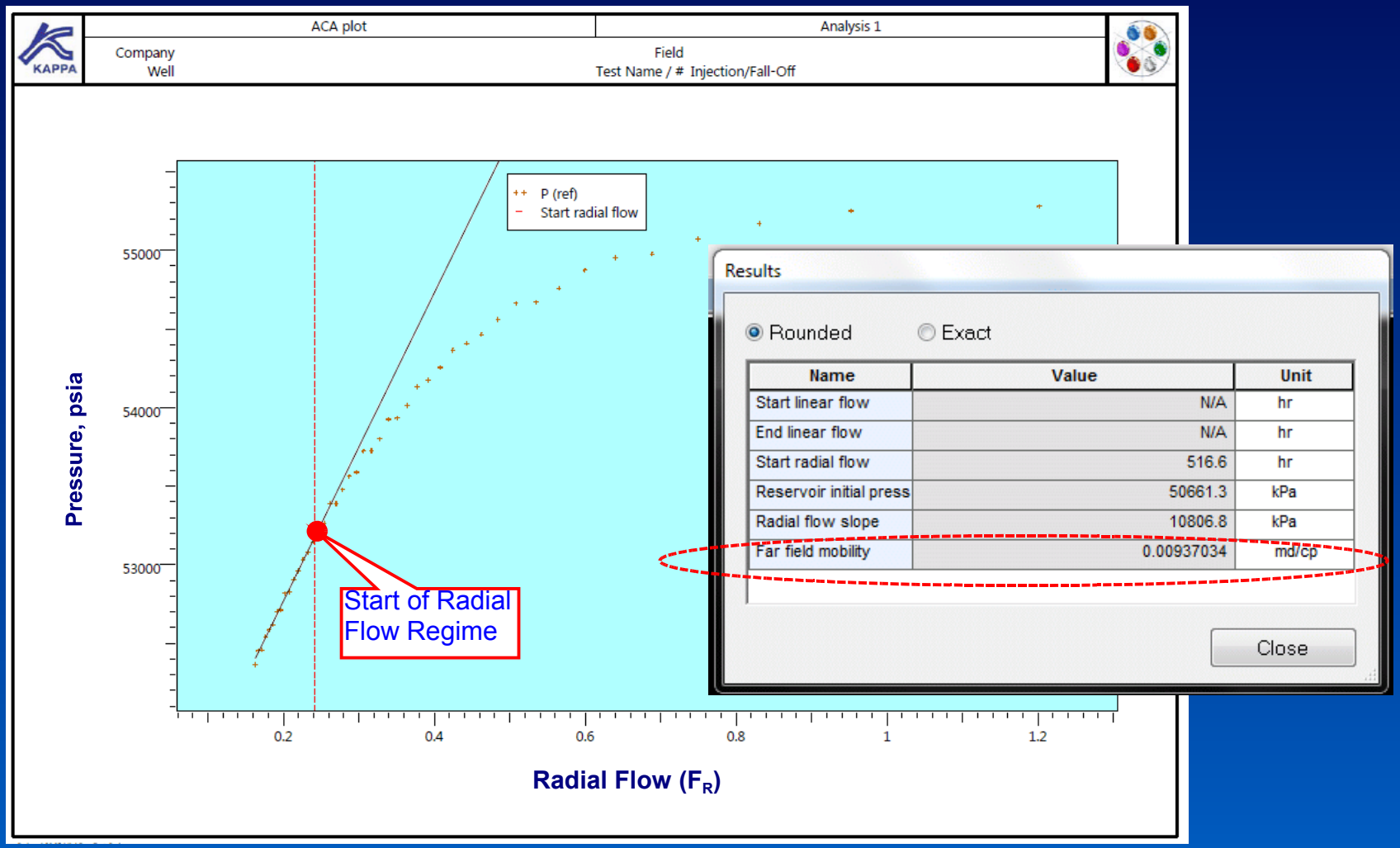
Identification of Closure Pressure
(Square Root Plot)



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

PMG

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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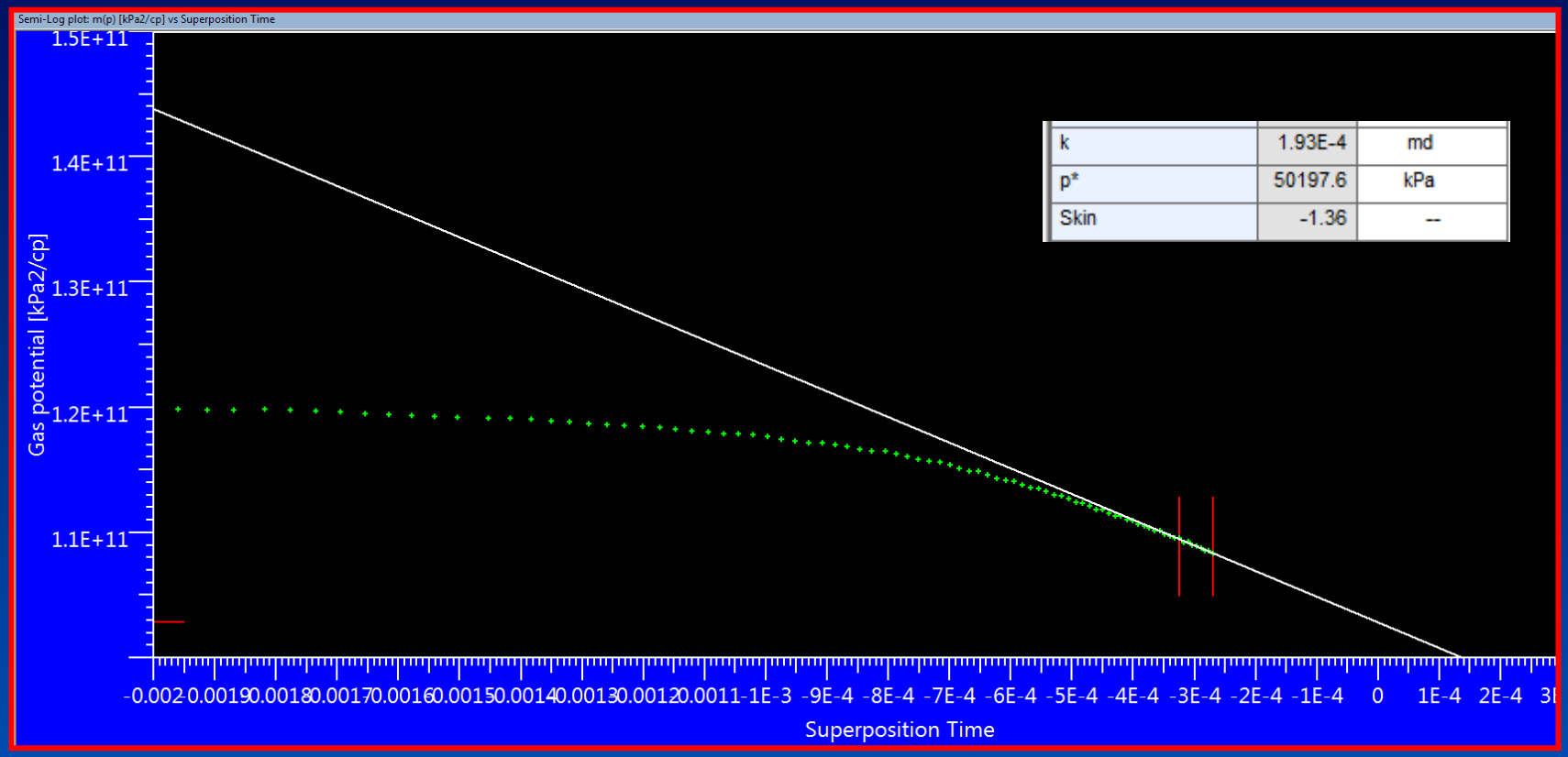
Horner Plot



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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

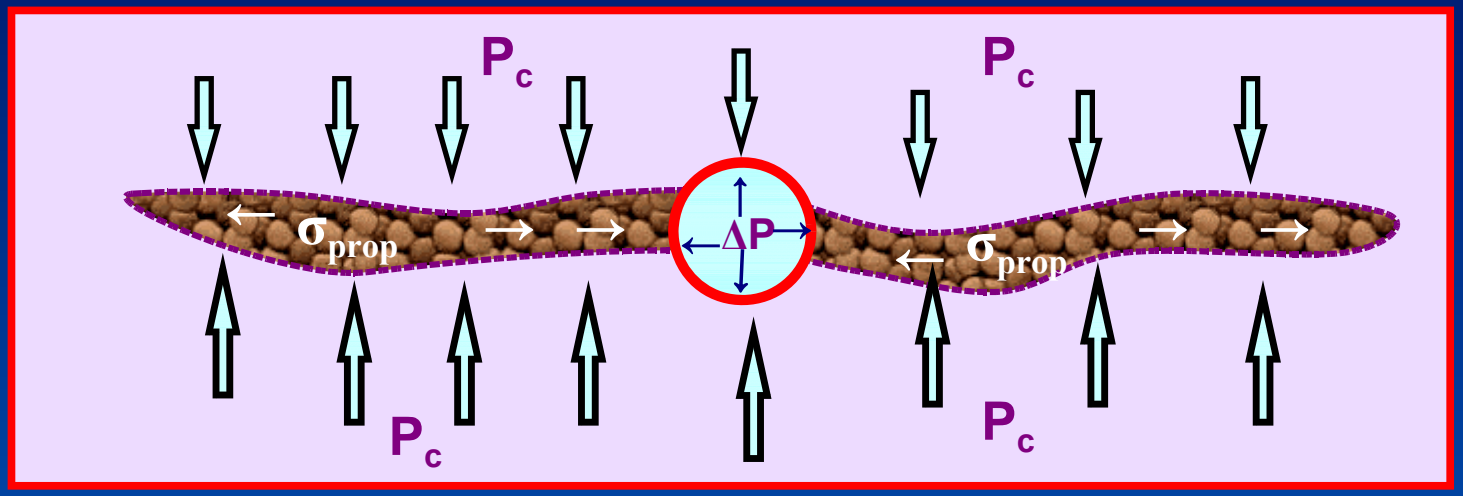
Design criteria:

- 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

P
M
G

Effect of Pressure Draw-down on Proppant Design

Proppants keep the frac aperture wide open:



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

Where:

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

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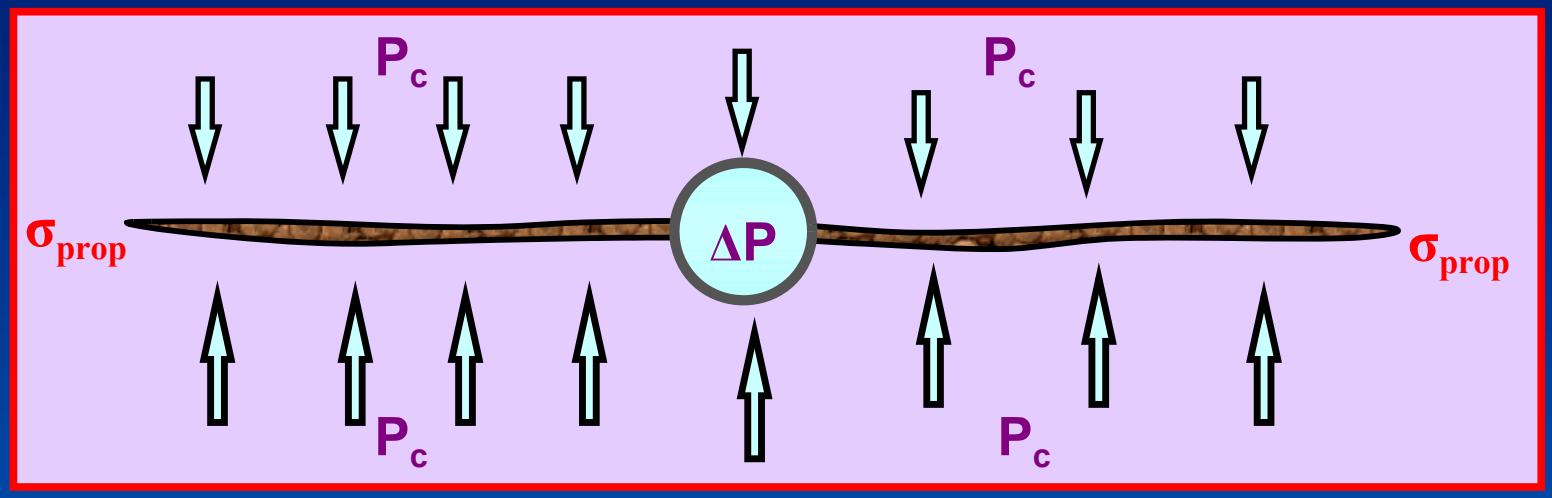
Effect of Pressure Draw-down on Proppant Design

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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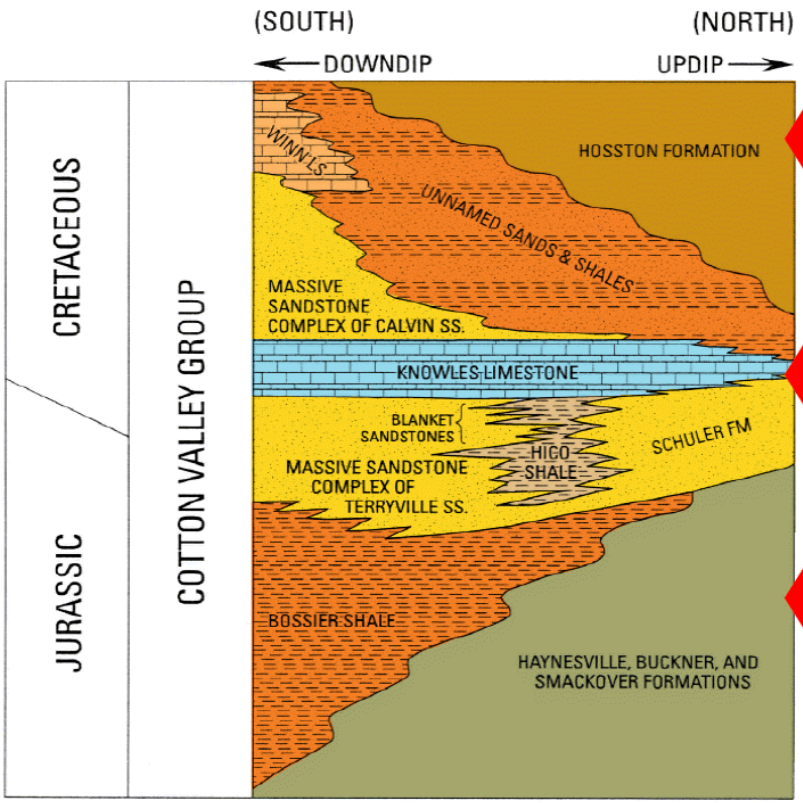
Stratigraphy



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.

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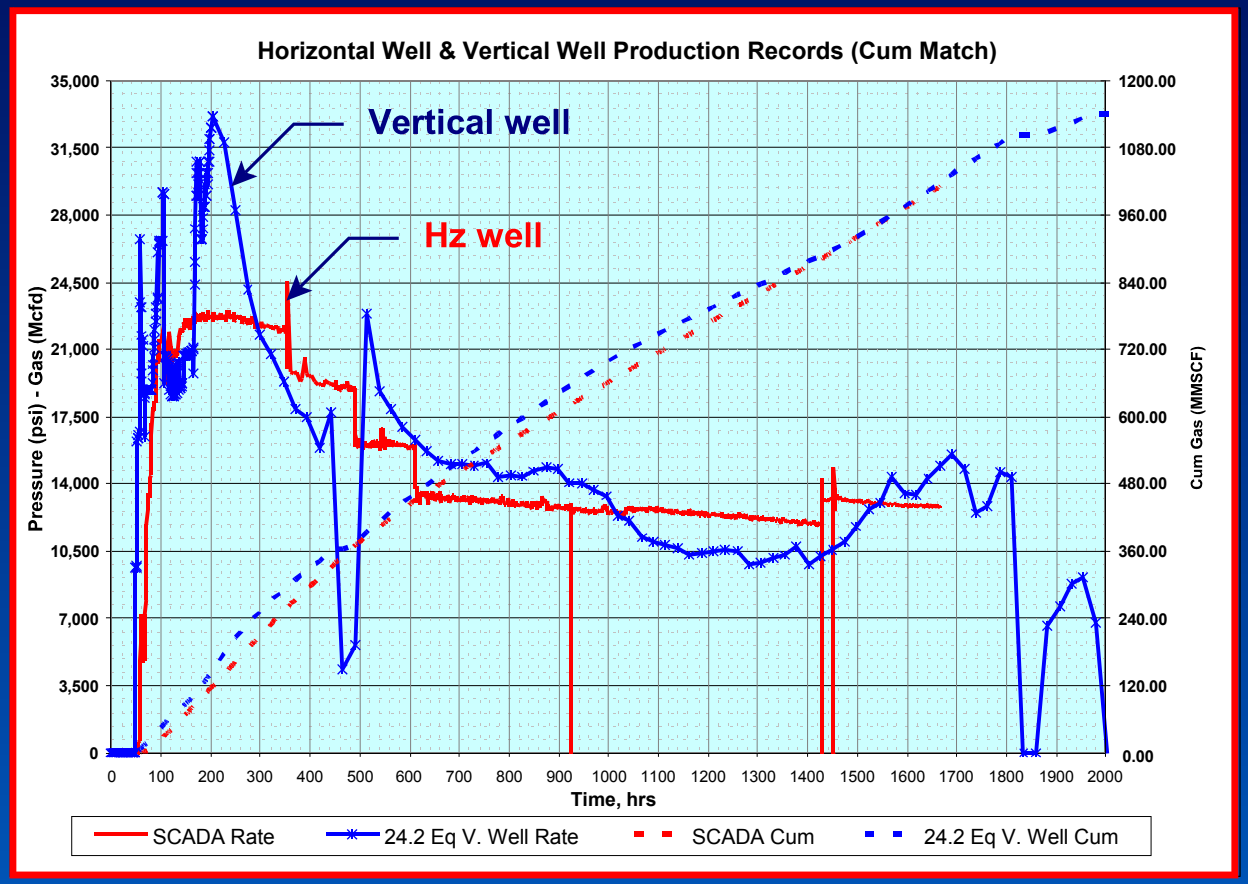
Performance Comparison
Vertical Well vs. 1st Hz Well



- 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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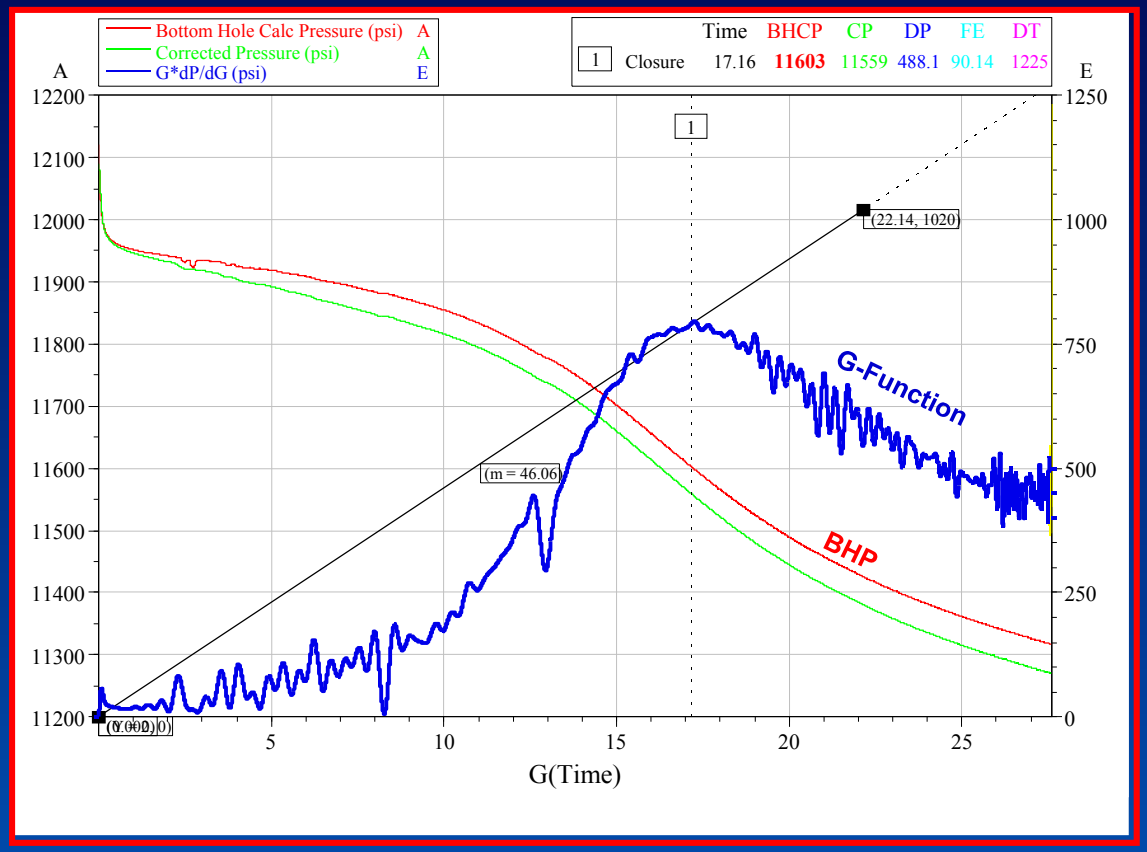
Critical Draw-down Pressure



Graph	Reservoir Pressure (psi)	Closure Pressure (psi)	Bottom Hole ISIP (psi)	Delta Pressure (psi)
			12091	
Minifrac - Horner	11108			
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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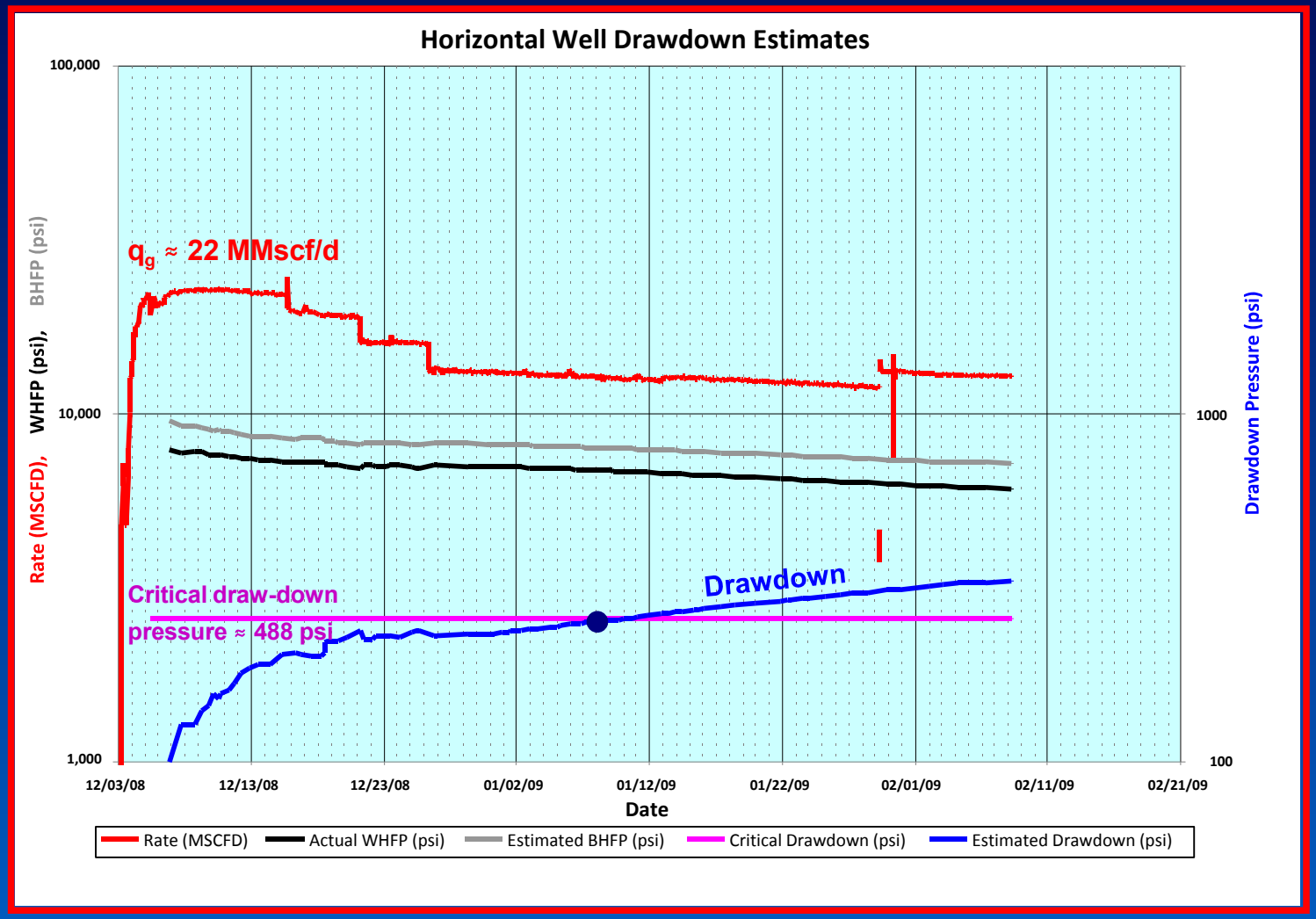
Draw-down Exceeded Critical Limit



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

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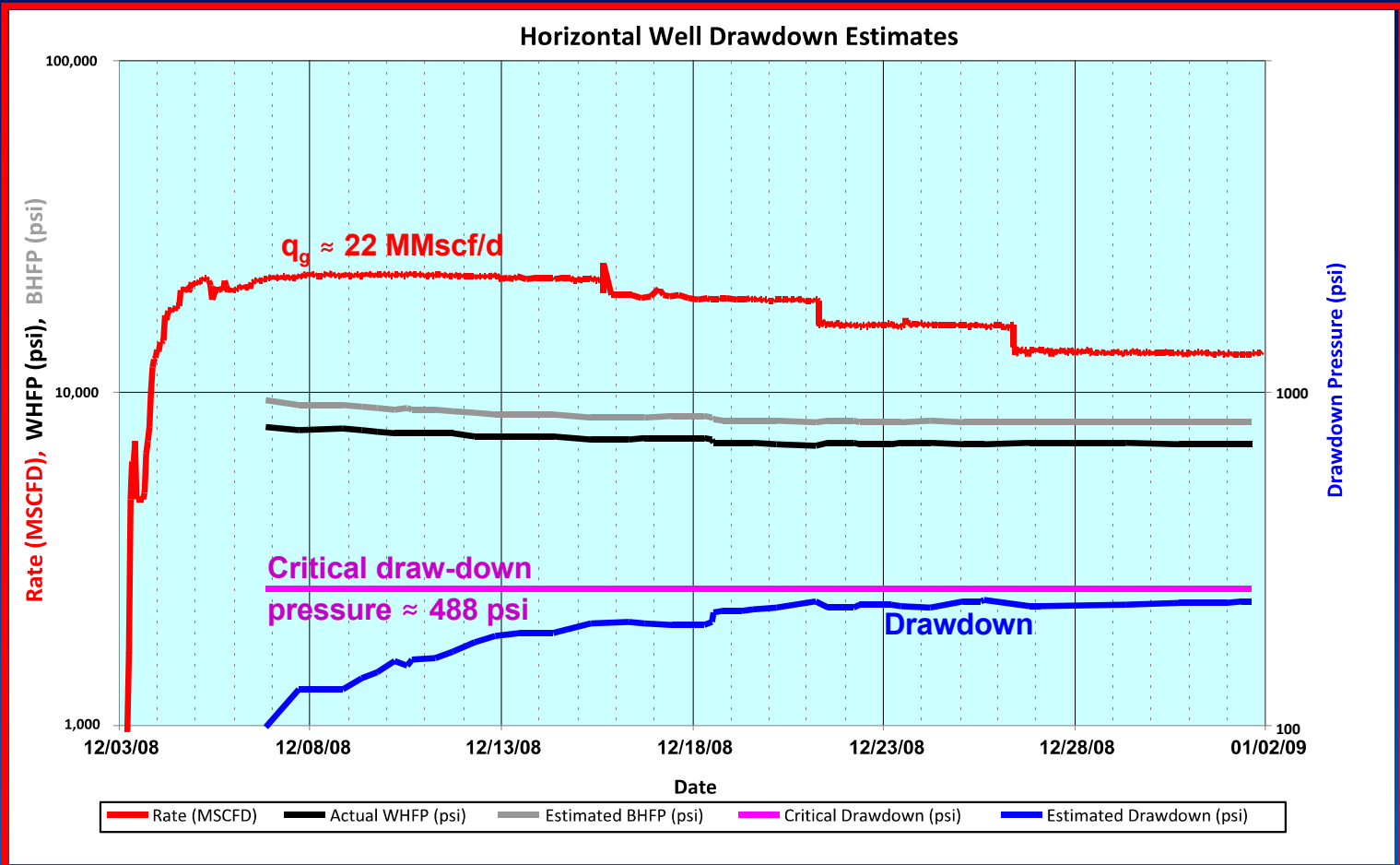
Draw-down Below Critical Limit
(one month of flow-back)



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

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Closing Comments

Benefits of Injectivity tests

- To assist in monitoring/improving injectivity for waterflood and disposal projects
- Set a sealing of steam injection pressure in thermal recovery projects
- The closure pressure, from DFIT, 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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Petro Management Group
Quality Petroleum Engineering Consultants

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