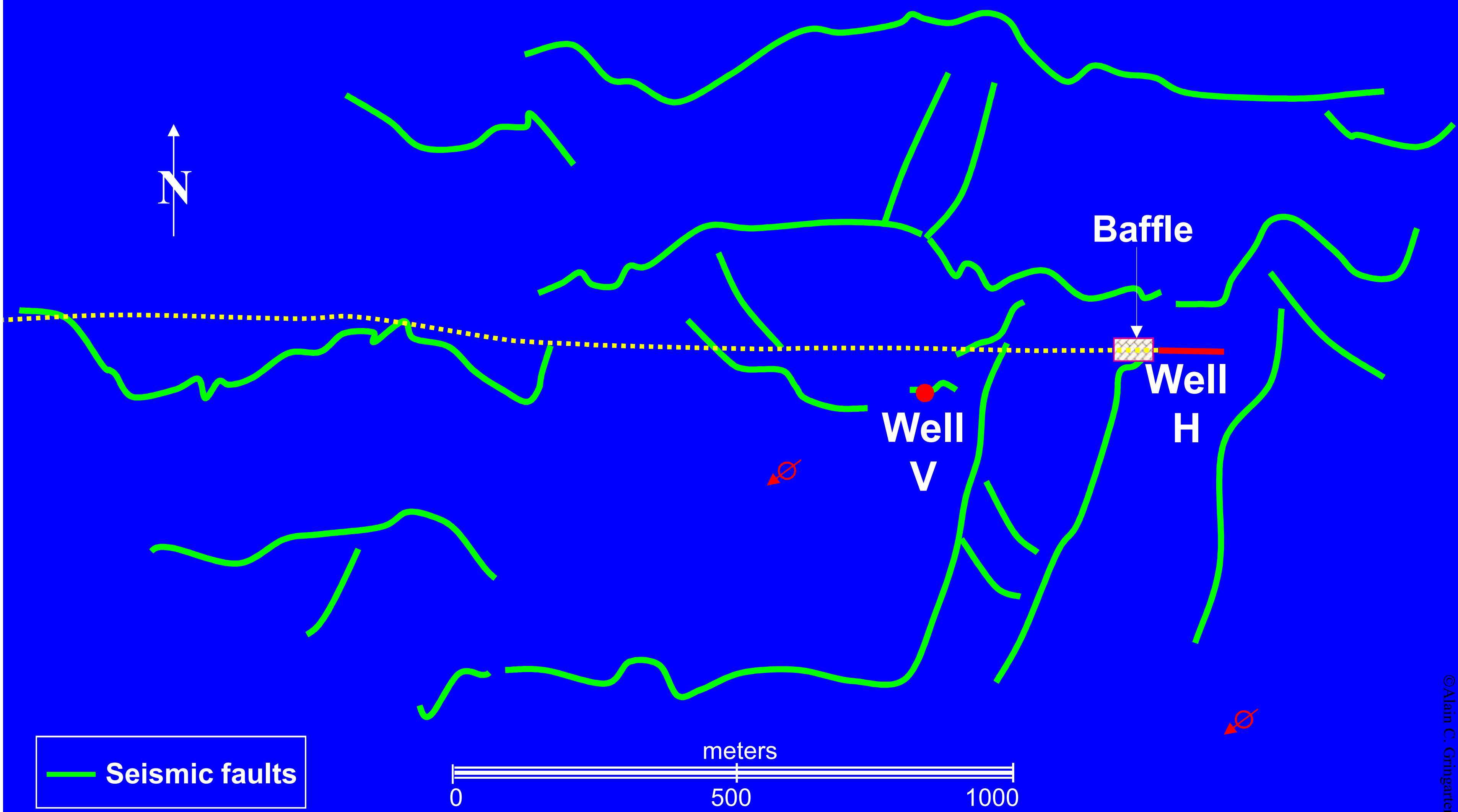
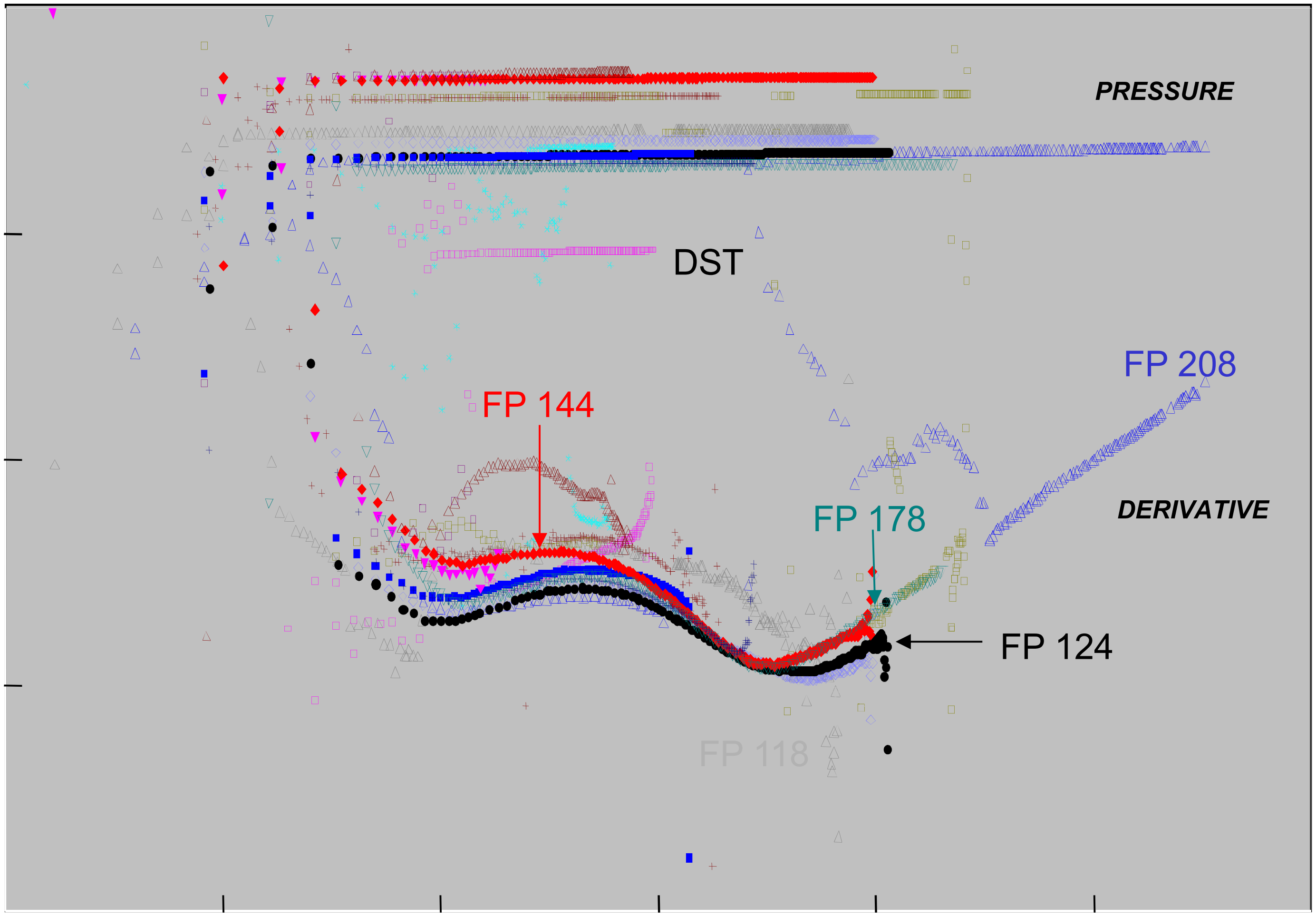
North Sea example

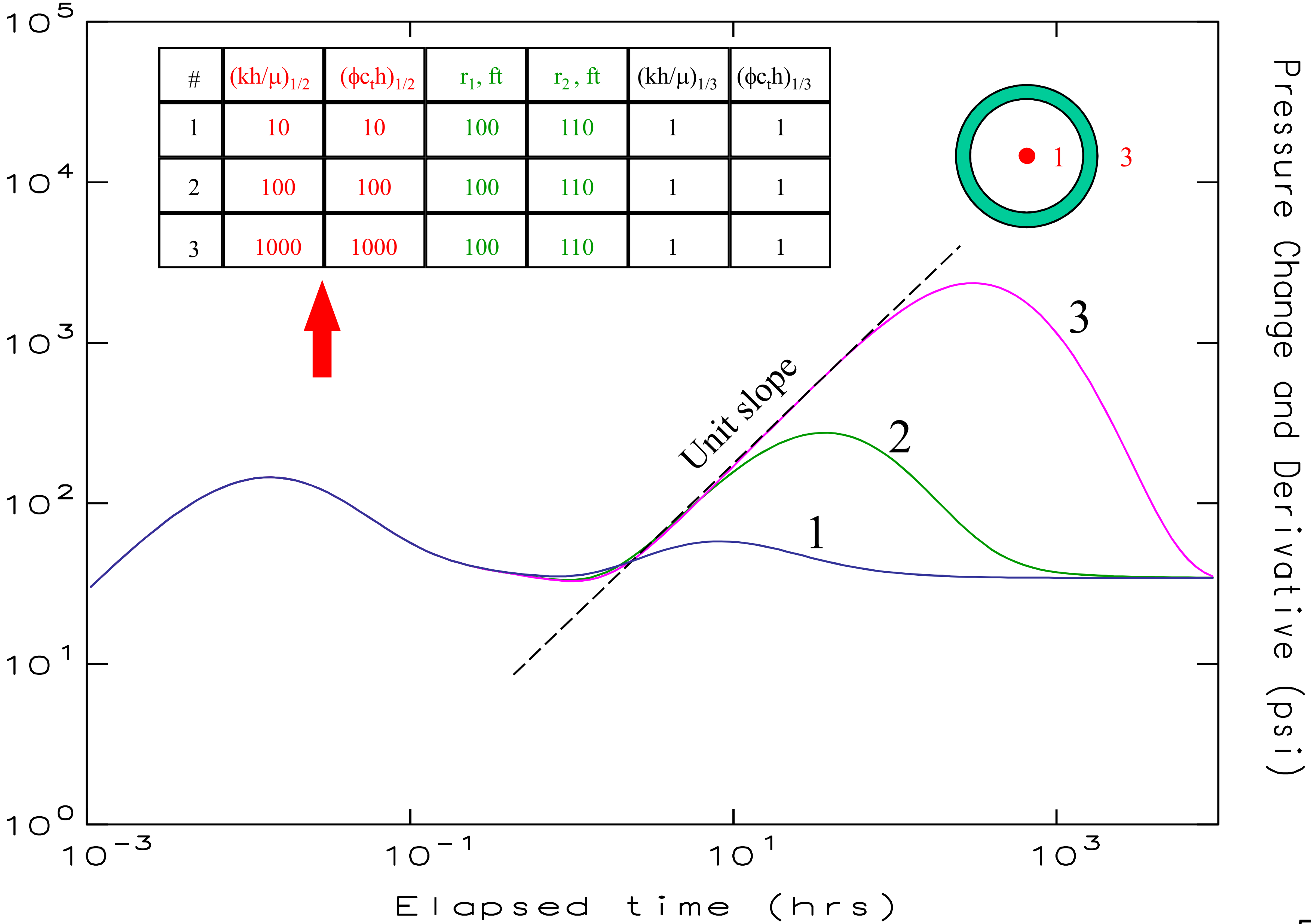


Analysis of extended test on Well V

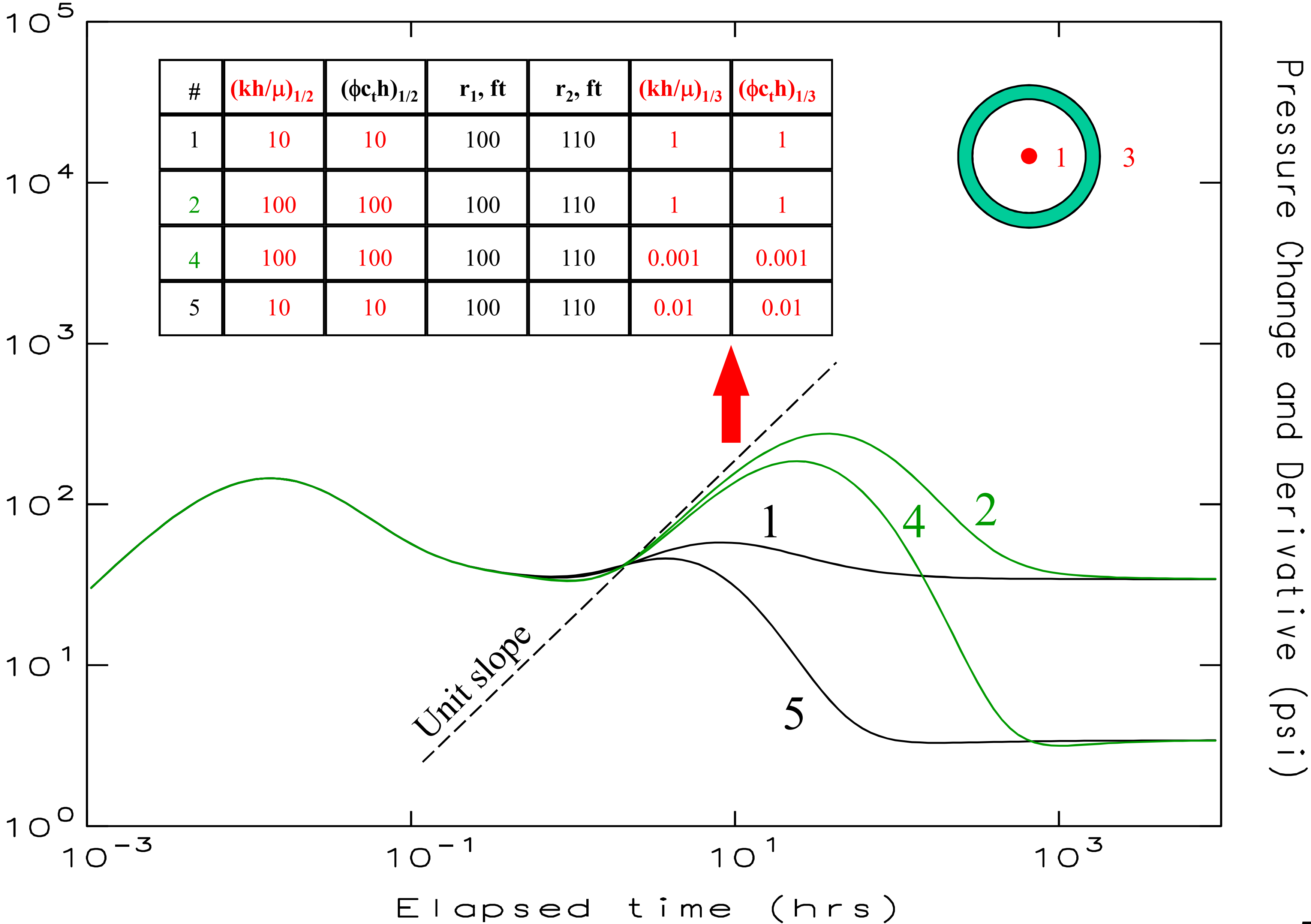


BAFFLES (Drawdown)

#	$(kh/\mu)_{1/2}$	$(\phi c_t h)_{1/2}$	r_1, ft	r_2, ft	$(kh/\mu)_{1/3}$	$(\phi c_t h)_{1/3}$
1	10	10	100	110	1	1
2	100	100	100	110	1	1
3	1000	1000	100	110	1	1



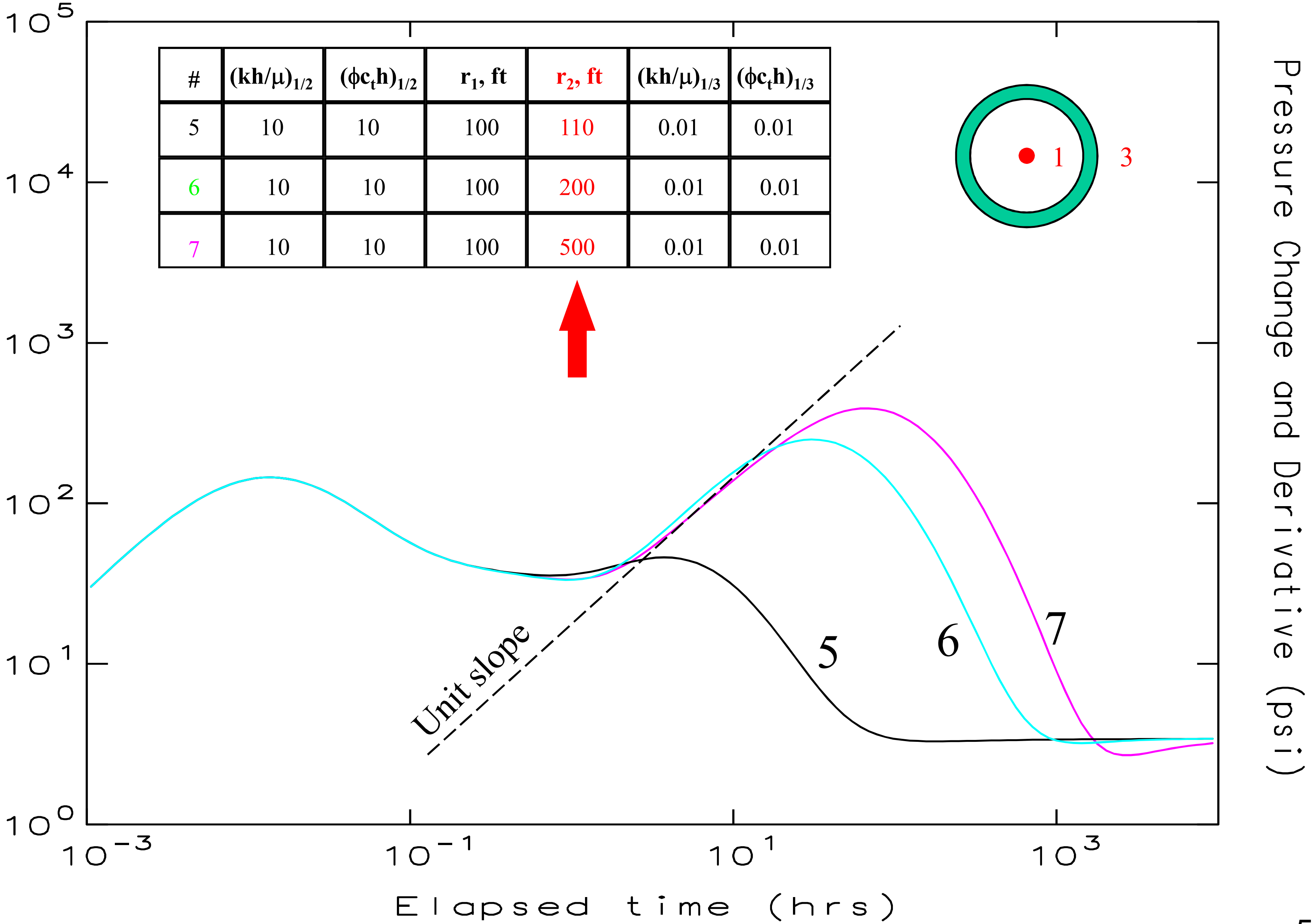
BAFFLES (Drawdown)



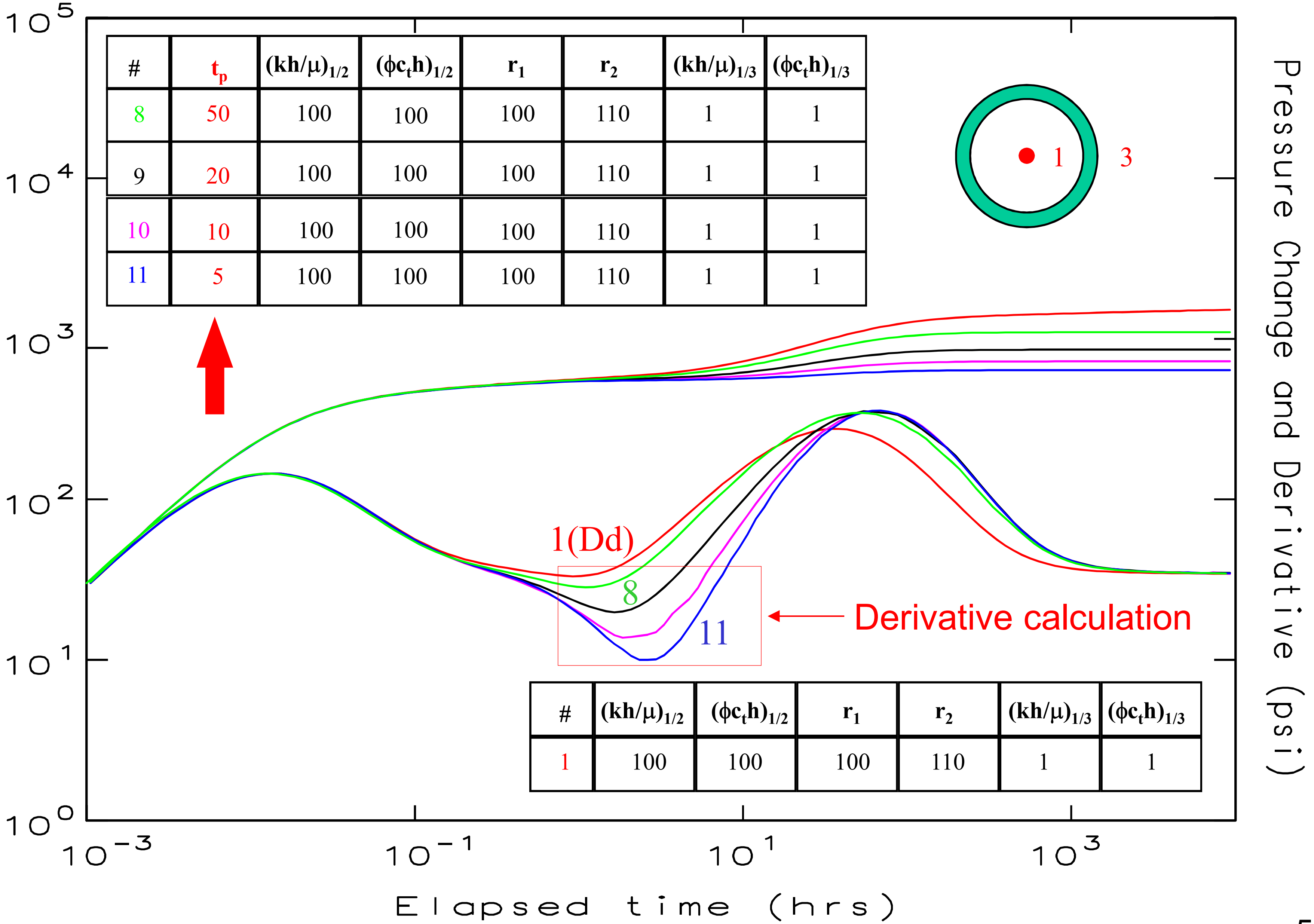
#	$(kh/\mu)_{1/2}$	$(\phi c_t h)_{1/2}$	r_1, ft	r_2, ft	$(kh/\mu)_{1/3}$	$(\phi c_t h)_{1/3}$
1	10	10	100	110	1	1
2	100	100	100	110	1	1
4	100	100	100	110	0.001	0.001
5	10	10	100	110	0.01	0.01

BAFFLES (Drawdown)

#	$(kh/\mu)_{1/2}$	$(\phi c_t h)_{1/2}$	r_1, ft	r_2, ft	$(kh/\mu)_{1/3}$	$(\phi c_t h)_{1/3}$
5	10	10	100	110	0.01	0.01
6	10	10	100	200	0.01	0.01
7	10	10	100	500	0.01	0.01



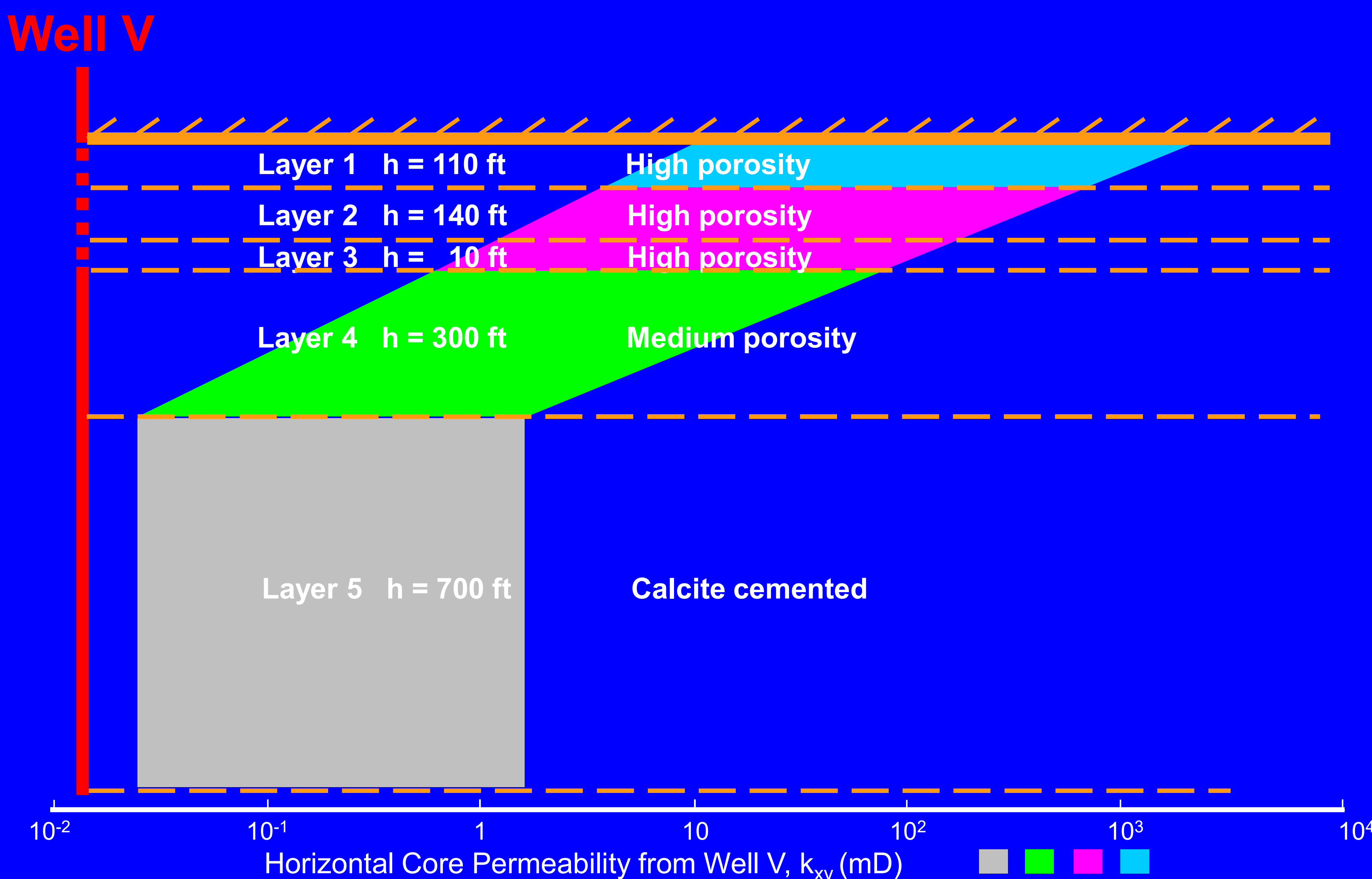
BAFFLES (Build-up)



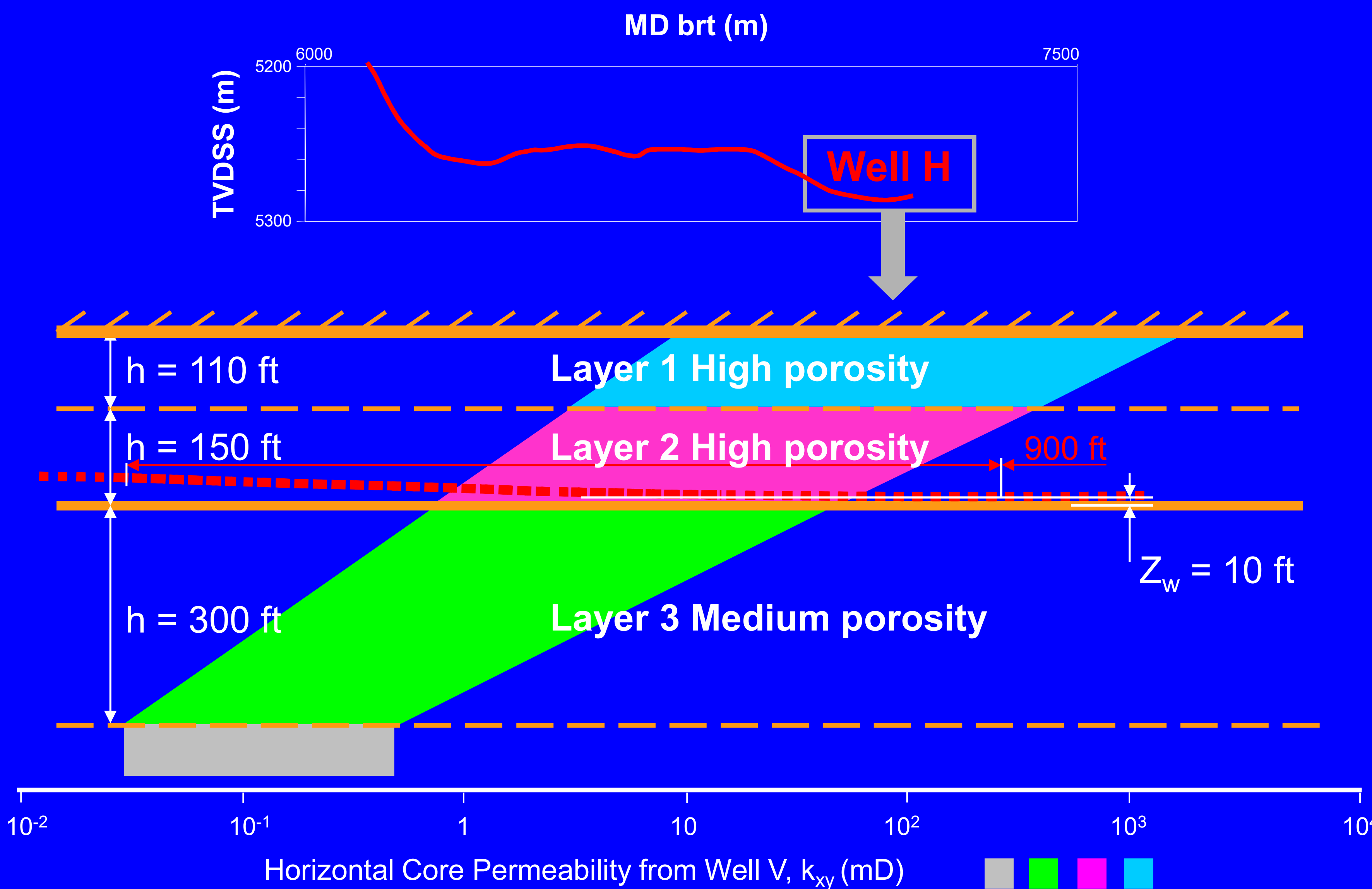
#	t_p	$(kh/\mu)_{1/2}$	$(\phi c_t h)_{1/2}$	r_1	r_2	$(kh/\mu)_{1/3}$	$(\phi c_t h)_{1/3}$
8	50	100	100	100	110	1	1
9	20	100	100	100	110	1	1
10	10	100	100	100	110	1	1
11	5	100	100	100	110	1	1

#	$(kh/\mu)_{1/2}$	$(\phi c_t h)_{1/2}$	r_1	r_2	$(kh/\mu)_{1/3}$	$(\phi c_t h)_{1/3}$
1	100	100	100	110	1	1

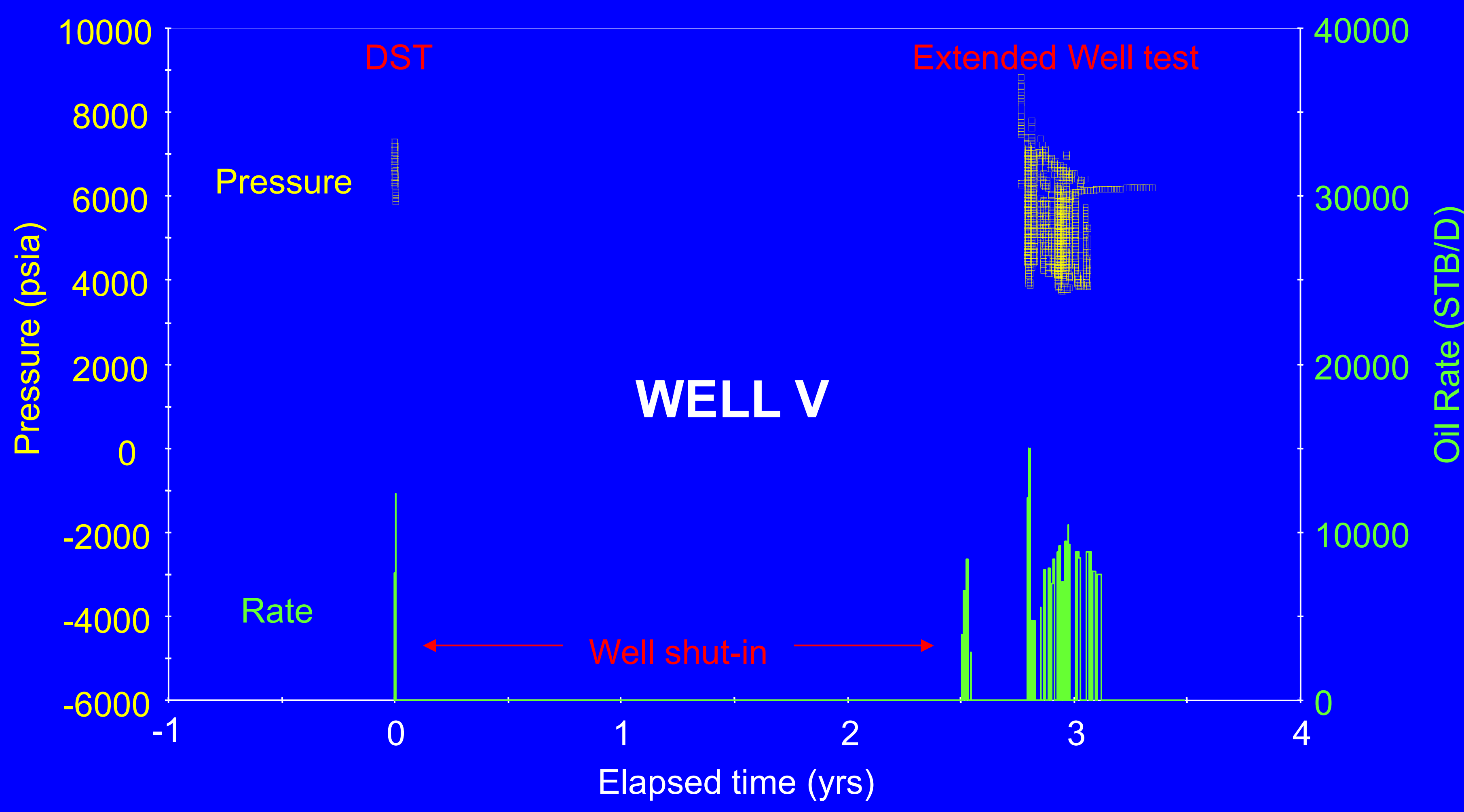
Cross section Well V



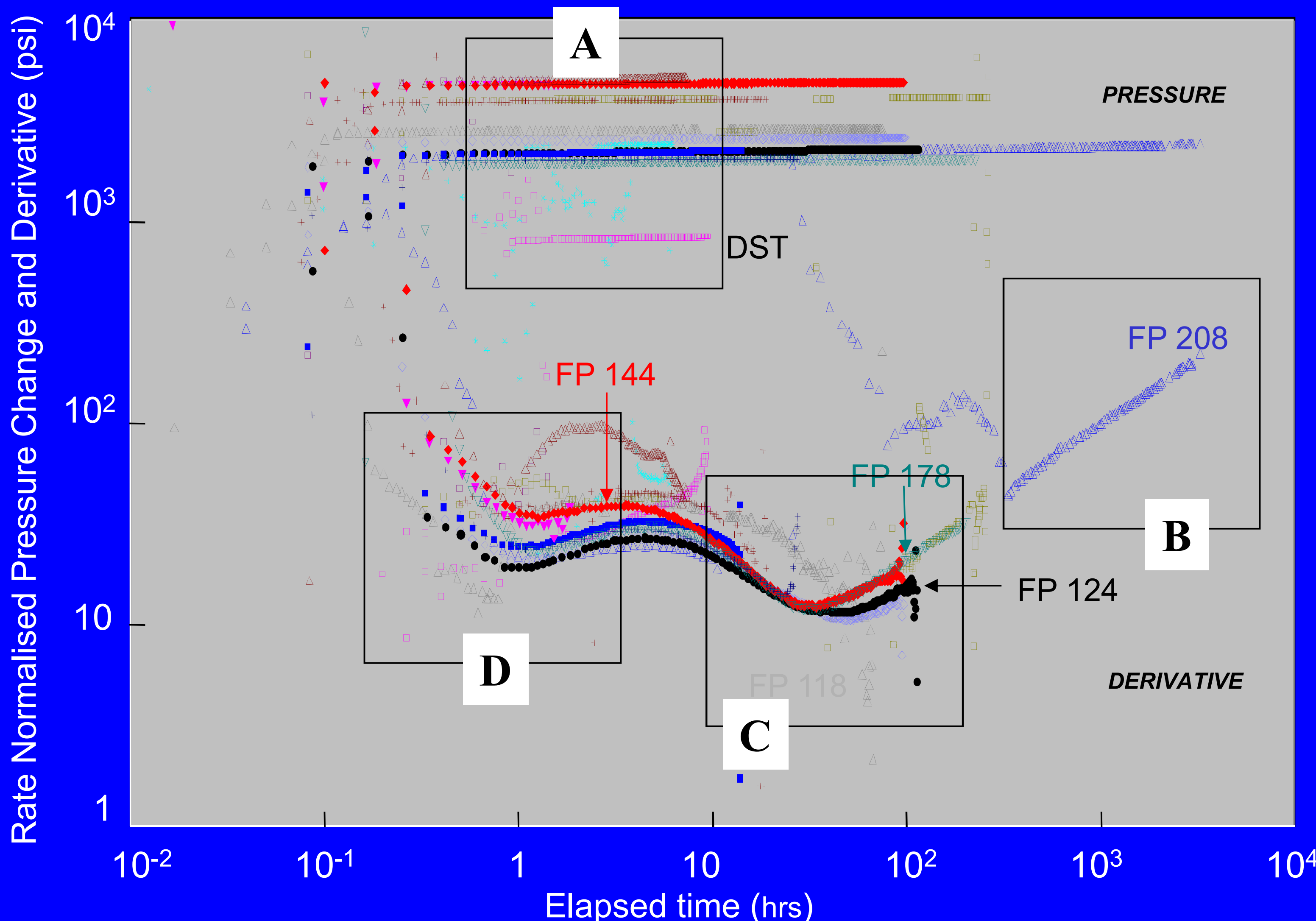
Cross section Well H



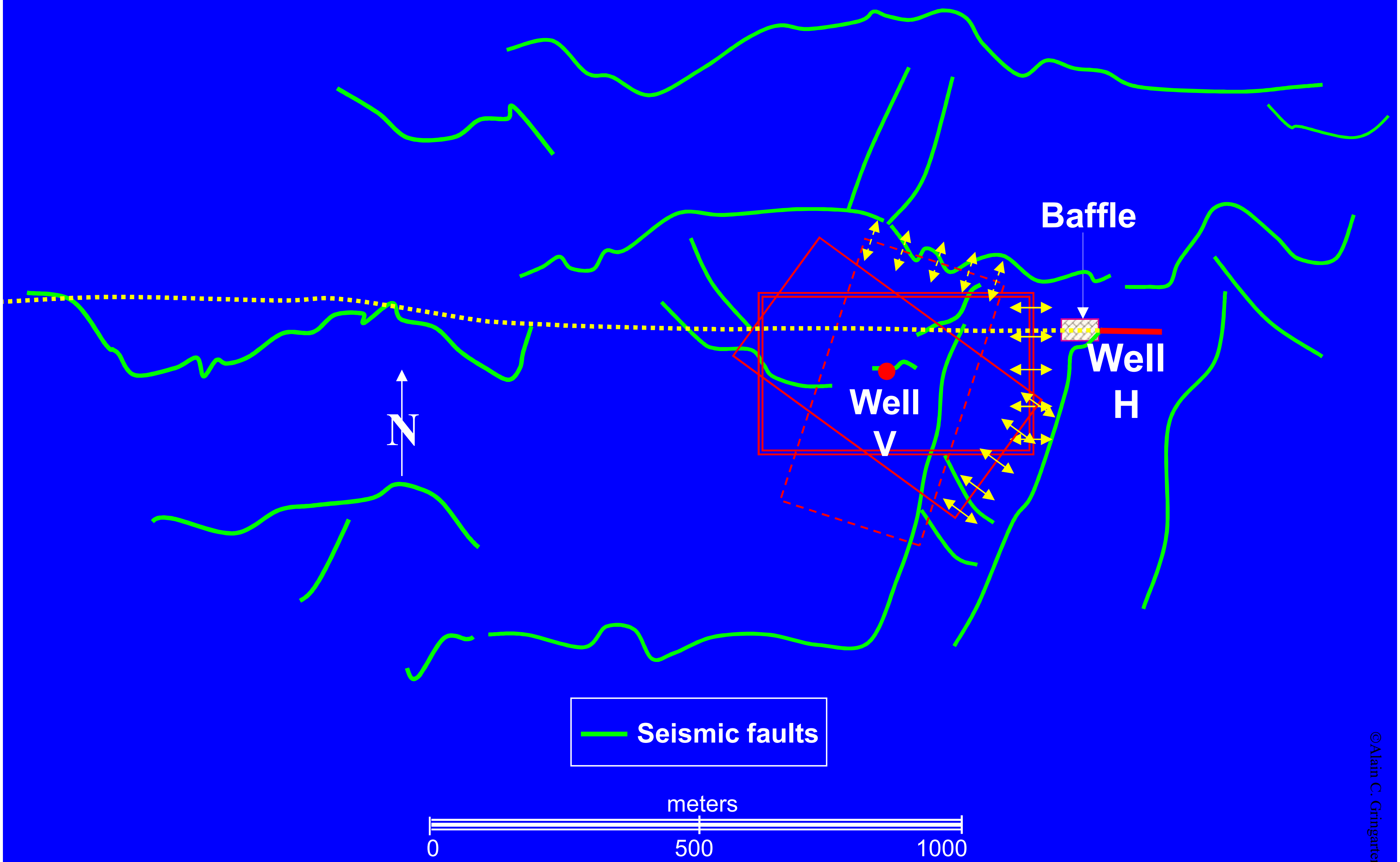
Extended test on Well V



Analysis of extended test on Well V

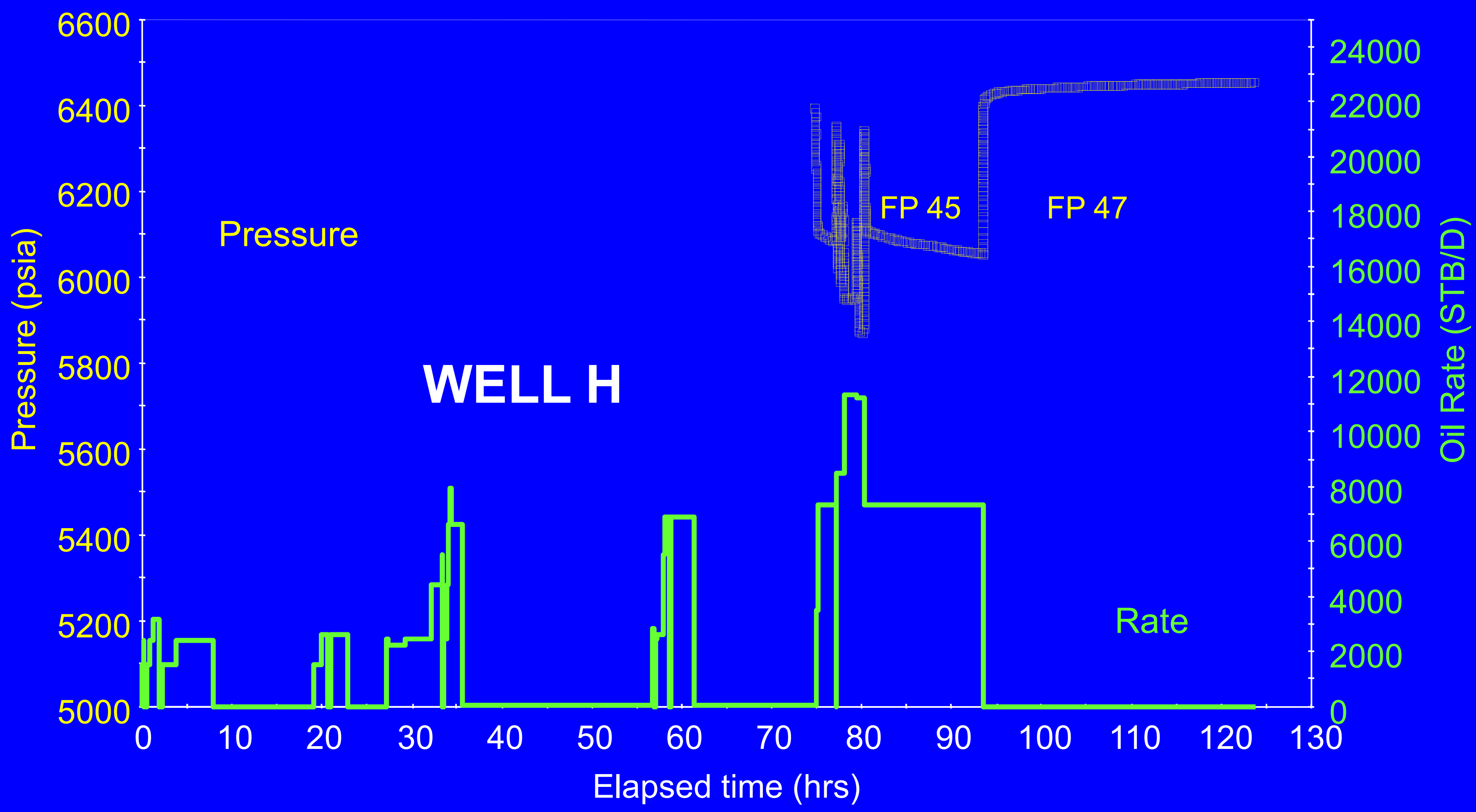


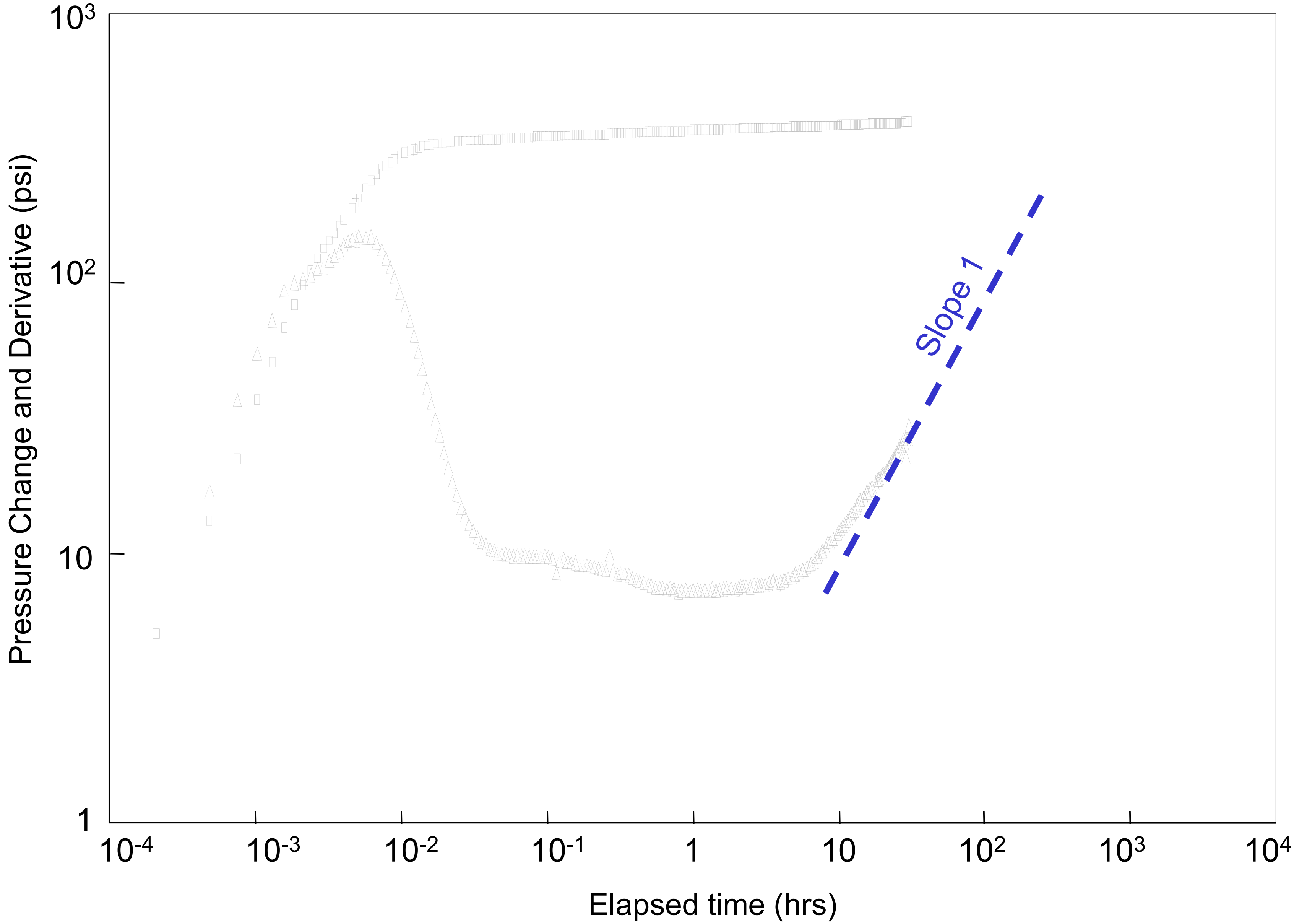
Boundaries from extended test on Well V

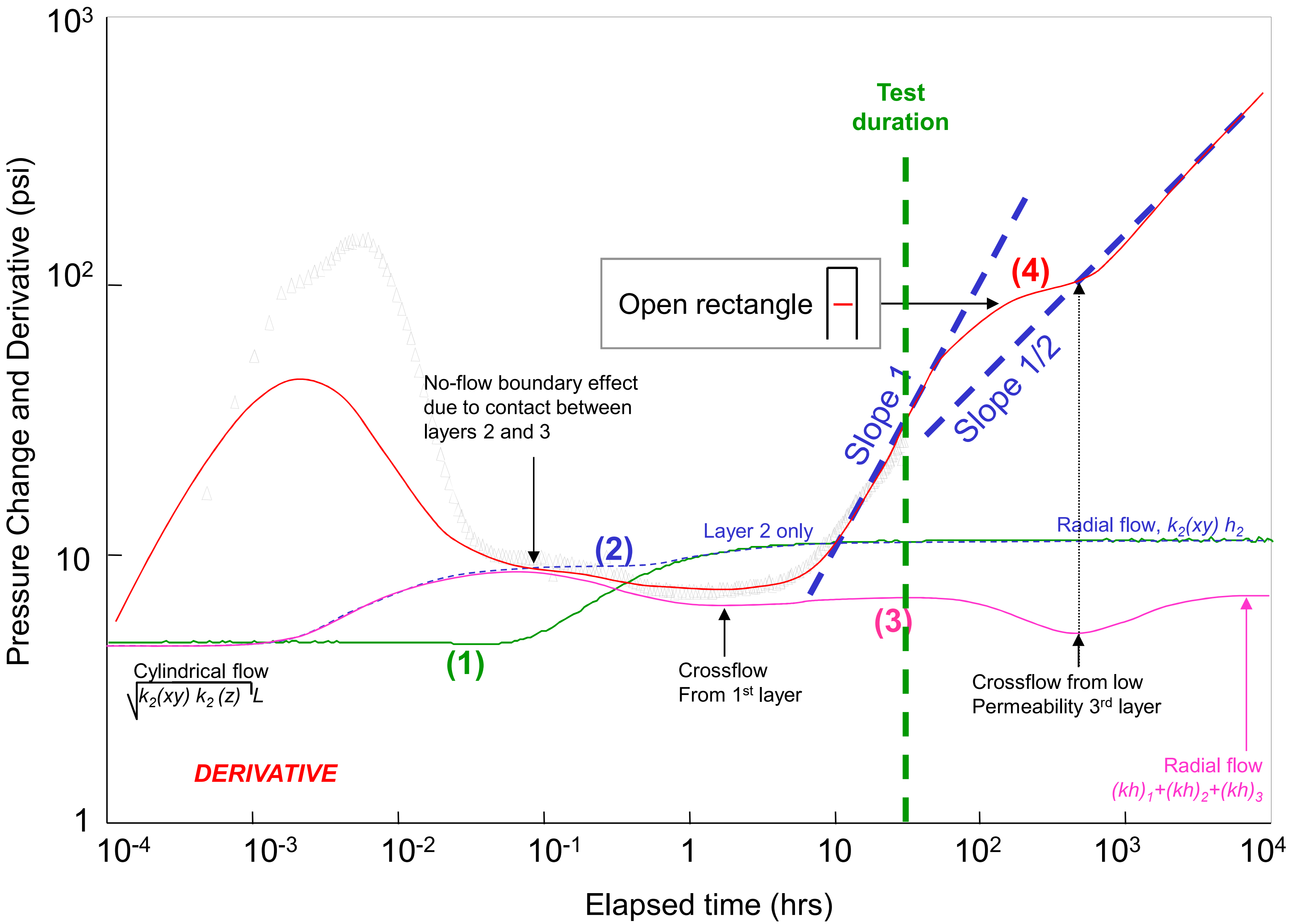


SPE 93988

Test on Well H

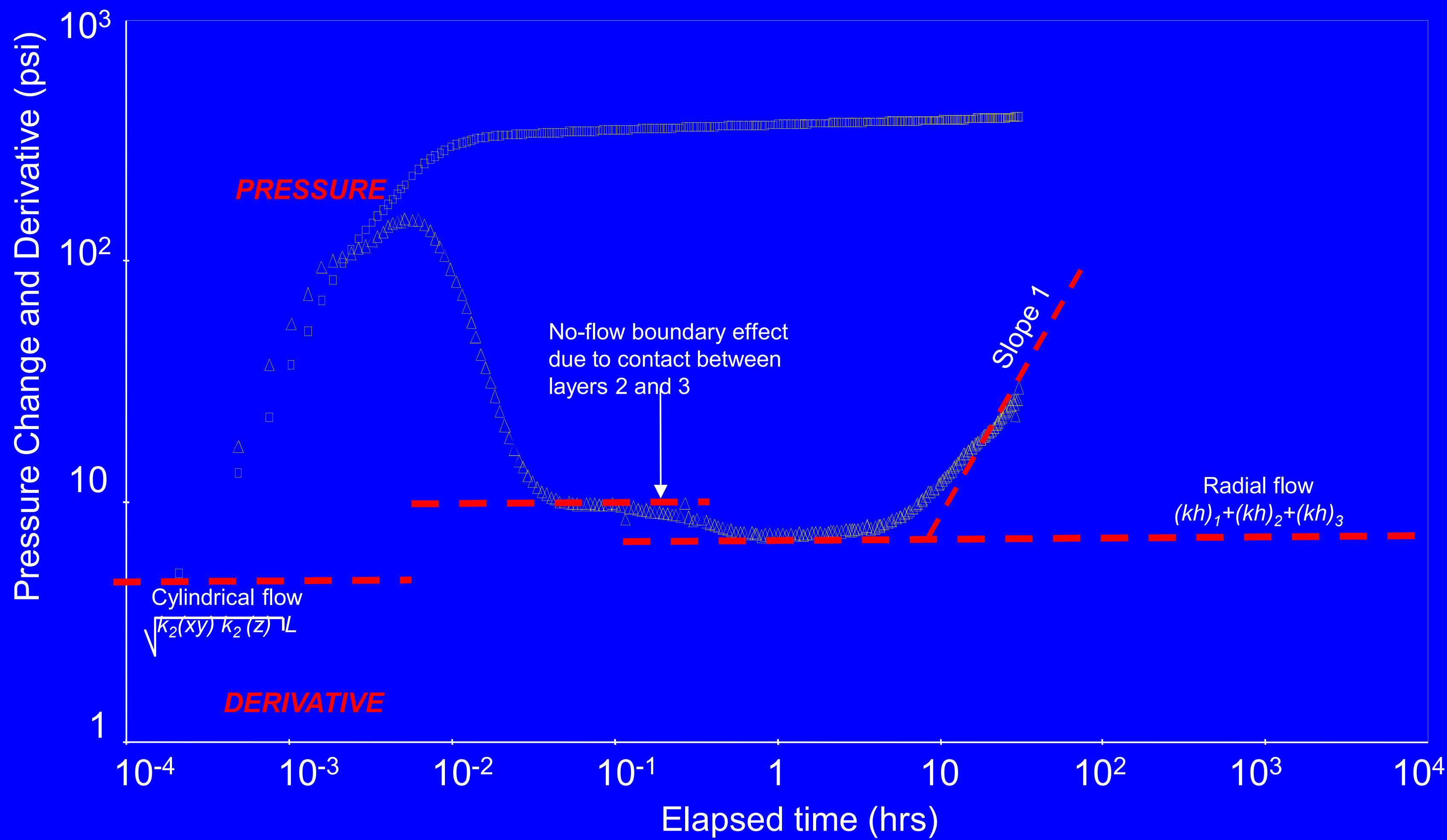



Pressure Change and Derivative (psi)
10³
10²
10
1
Slope 1
10⁻⁴
10⁻³
10⁻²
10⁻¹
1
10
10²
10³
10⁴
Elapsed time (hrs)

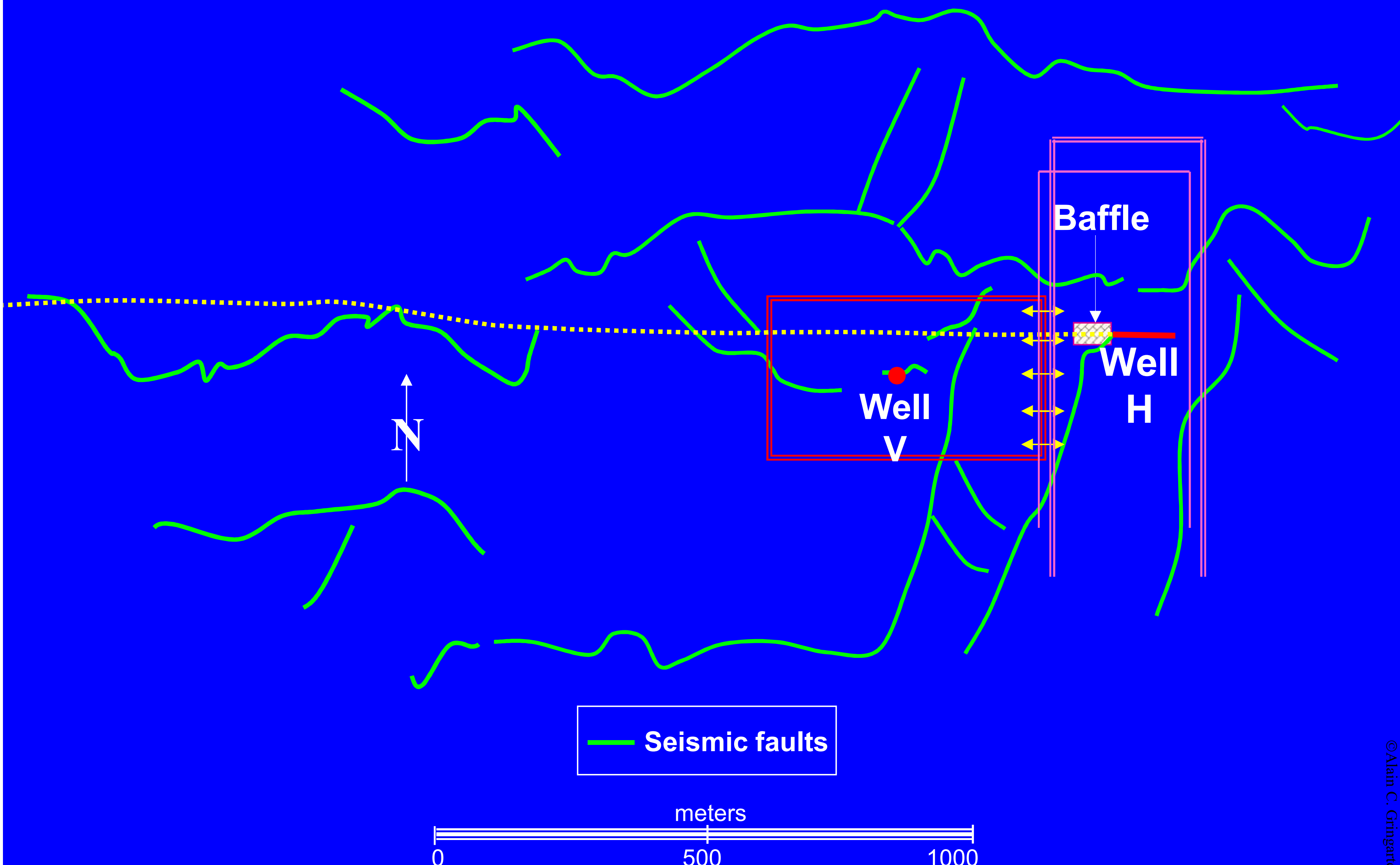


Pressure Change and Derivative (psi)
10³
10²
10
1
Elapsed time (hrs)
10⁻⁴
10⁻³
10⁻²
10⁻¹
1
10
10²
10³
10⁴
Test duration
Open rectangle
(4)
Slope 1
Slope 1/2
No-flow boundary effect due to contact between layers 2 and 3
(2)
Layer 2 only
Radial flow, k2(xy) h2
(3)
(1)
Cylindrical flow
√k2(xy) k2 (z) L
Crossflow From 1st layer
Crossflow from low Permeability 3rd layer
Radial flow (kh)1+(kh)2+(kh)3
DERIVATIVE

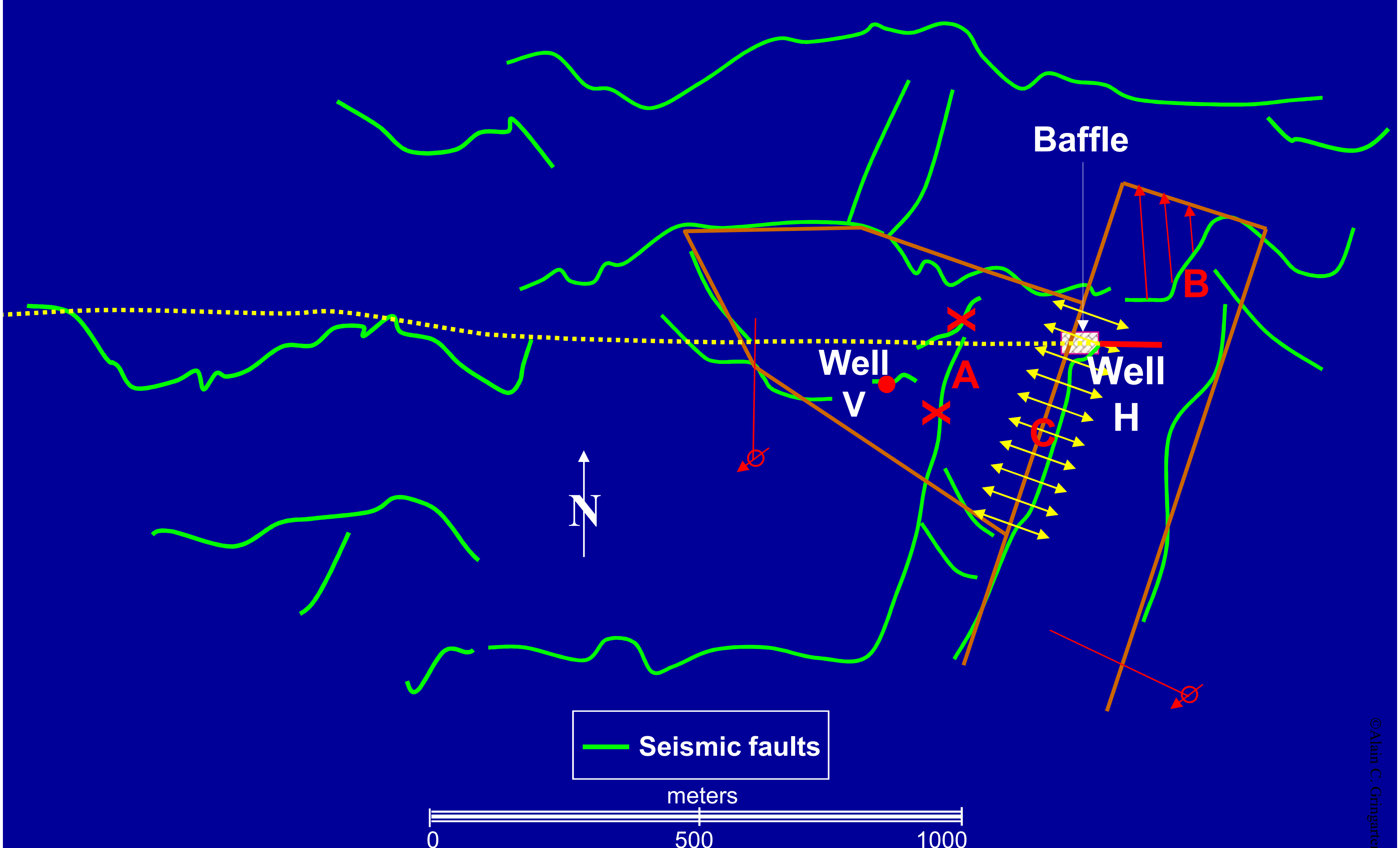
Analysis of test on Well H



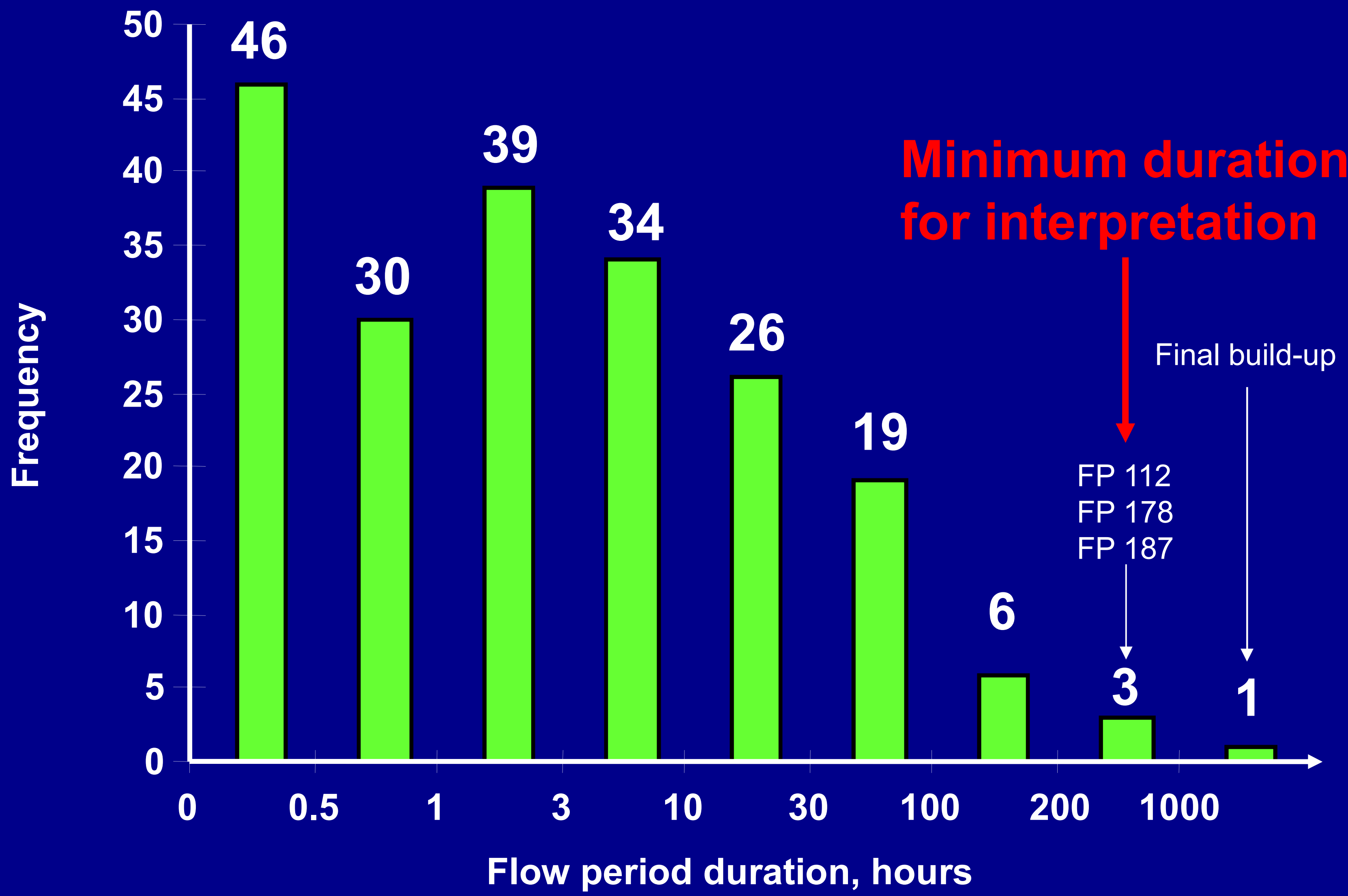
Boundaries from test on Well H



Boundaries from tests on Wells V and H

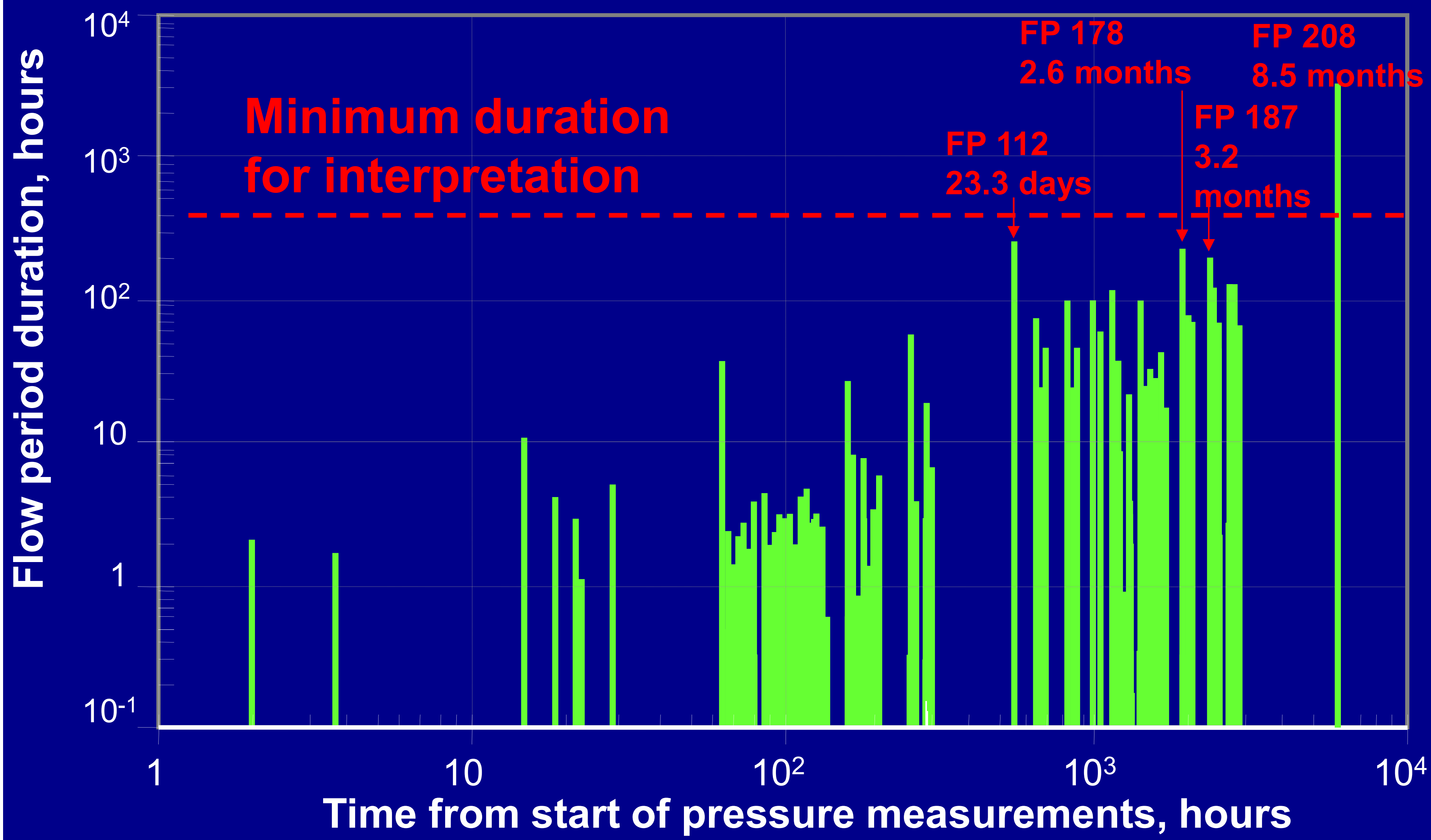


Shortening of reservoir limit tests



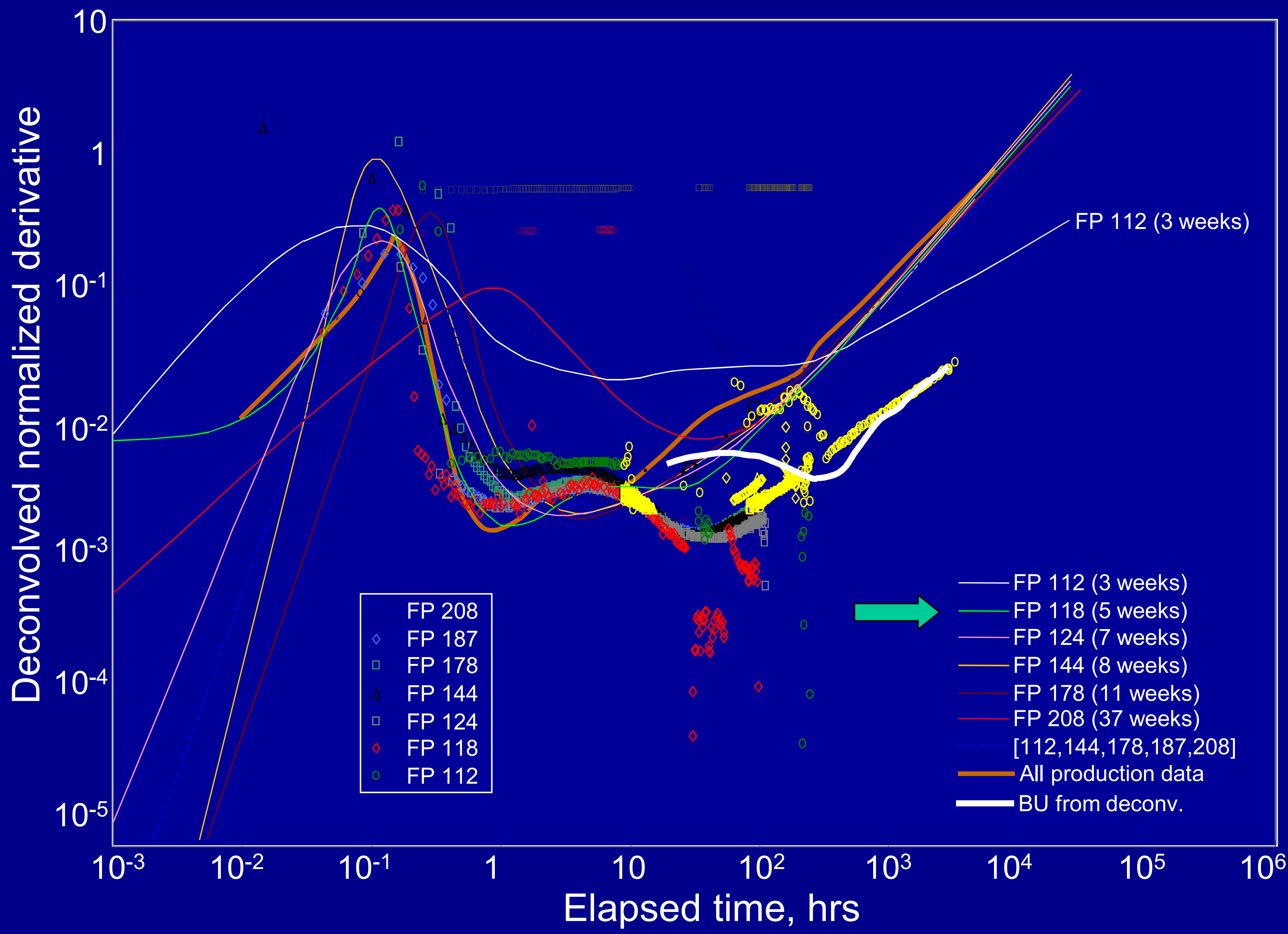
SPE 93988

Shortening of reservoir limit tests



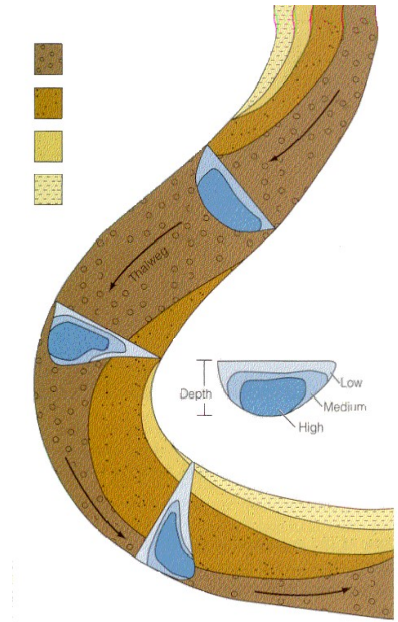
SPE 93988

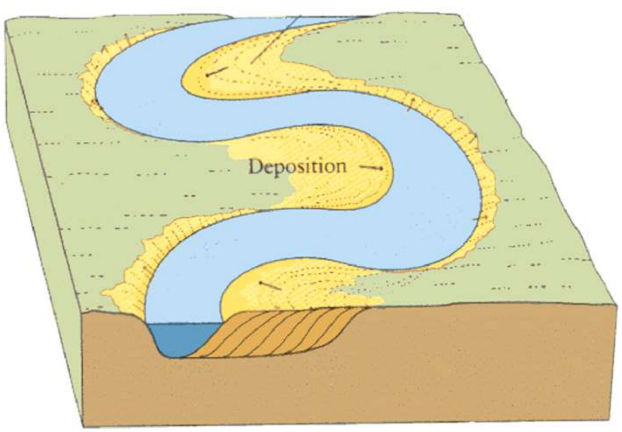
Shortening of reservoir limit tests



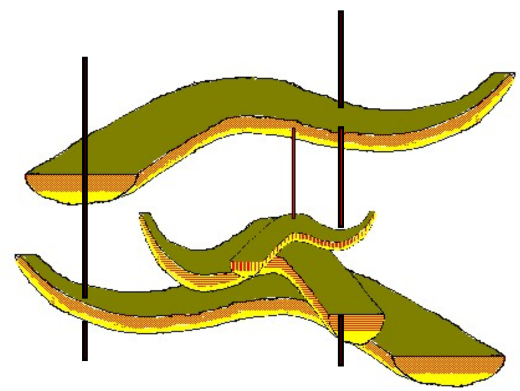
SPE 93988

Complex sandstone bodies

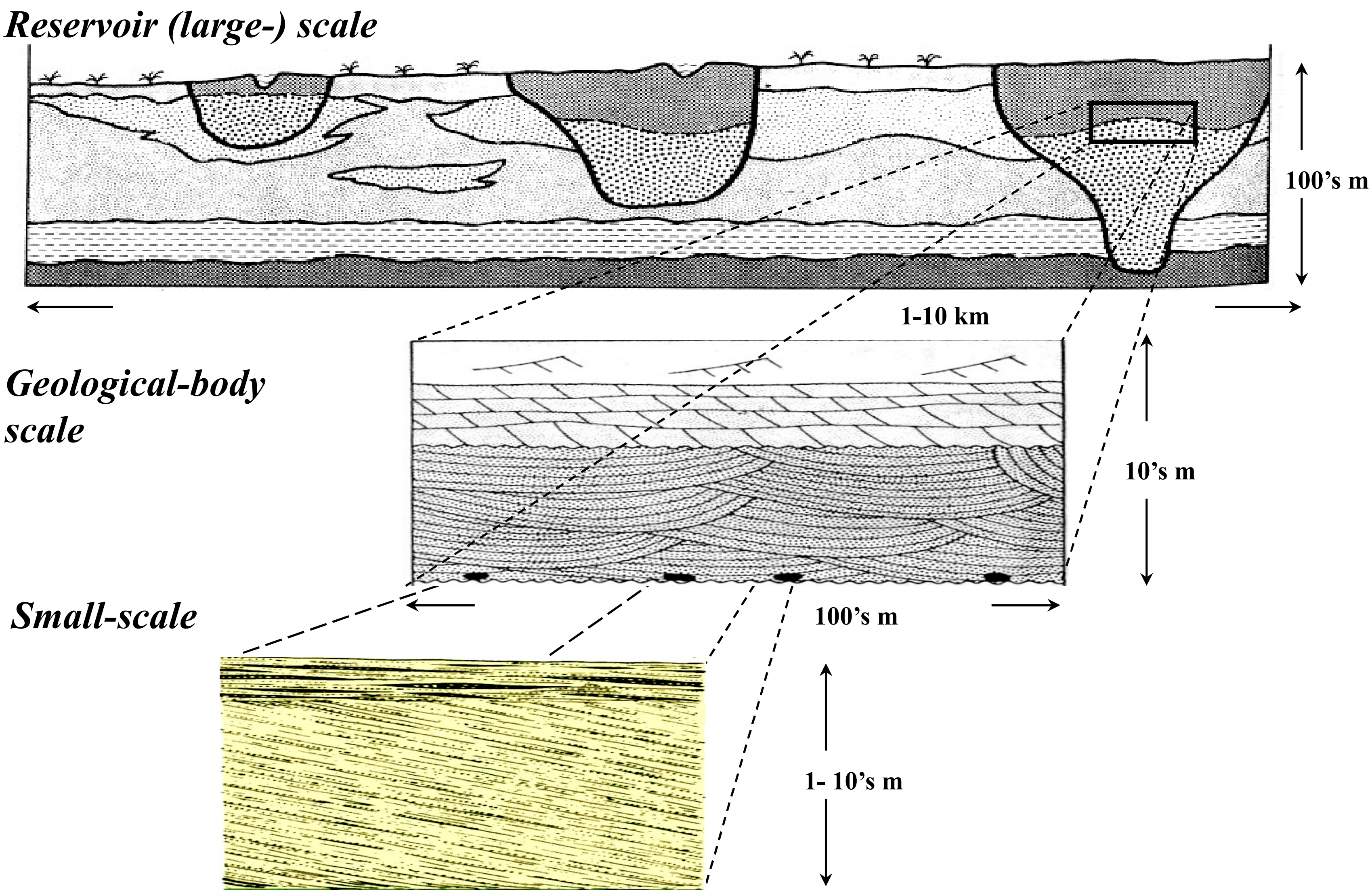




Transverse Cross-sections

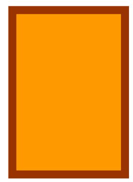
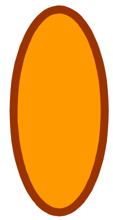
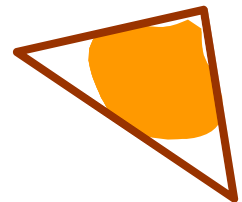
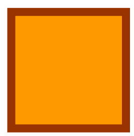
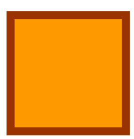
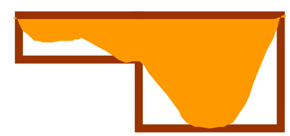


LEVELS OF RESERVOIR HETEROGENEITY

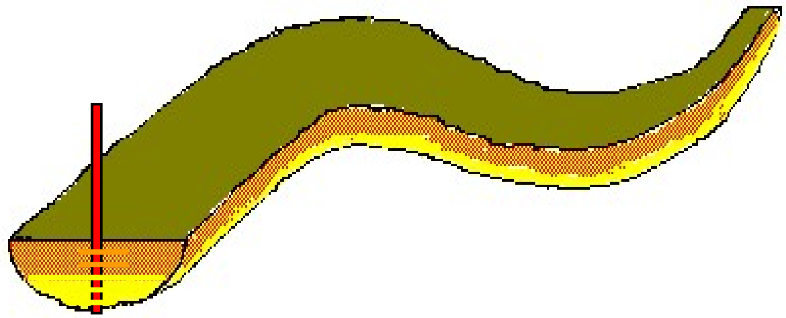


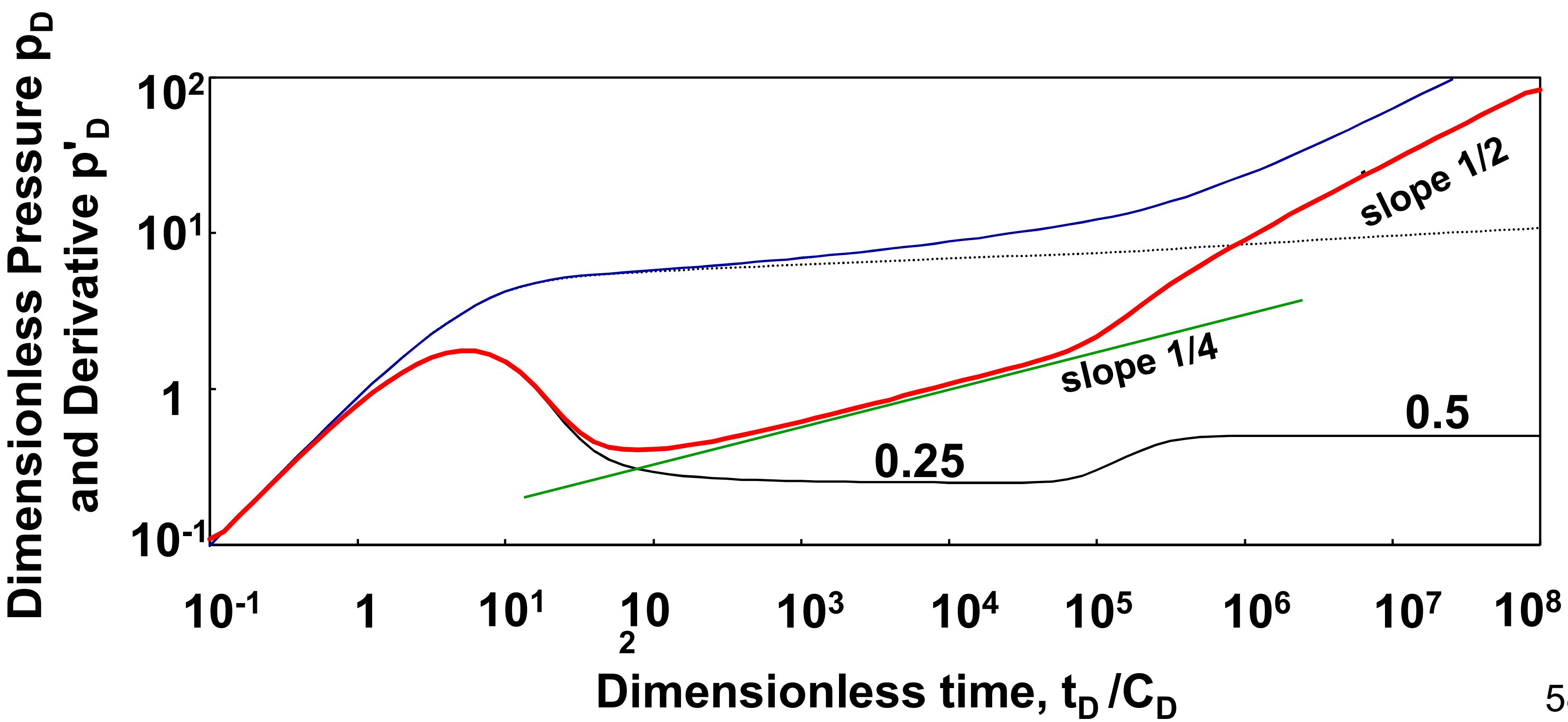
(Example in Deltaic Reservoir)

Genetic-type Objects

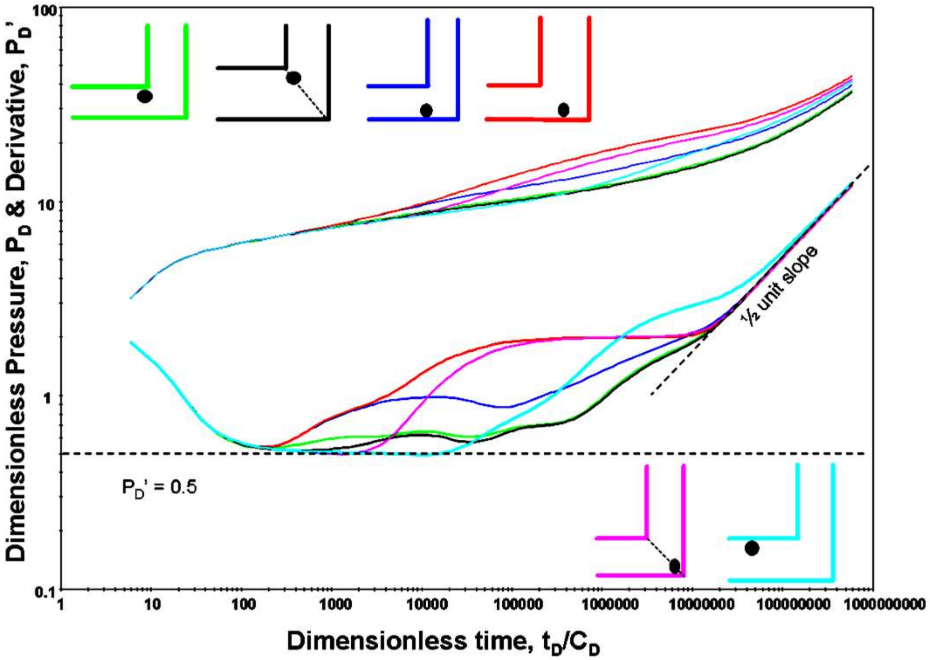
PLAN VIEW	XY-profile				
		Straight	Elongate	Fan / Lobate	Sinuous
THICKNESS PROFILES	YZ-profile (Longitudinal)				
		Constant	Increasing Composite	Decreasing Composite	
	XZ-profile (Transverse)				
		Constant	Symmetrical Composite	Asymmetrical Composite	

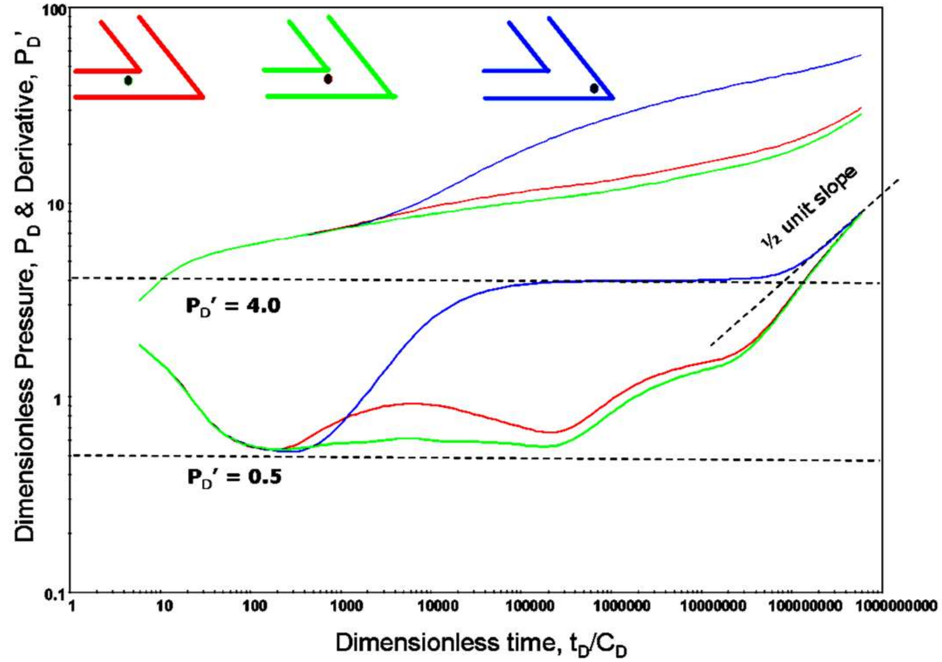
TWO-POROSITY CHANNEL

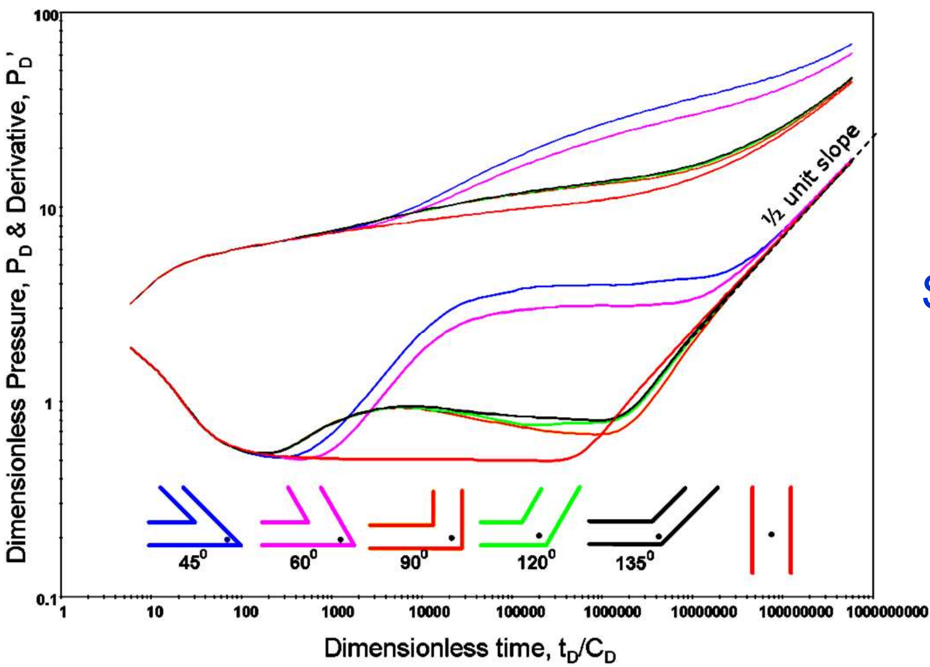




MEANDERING CHANNEL

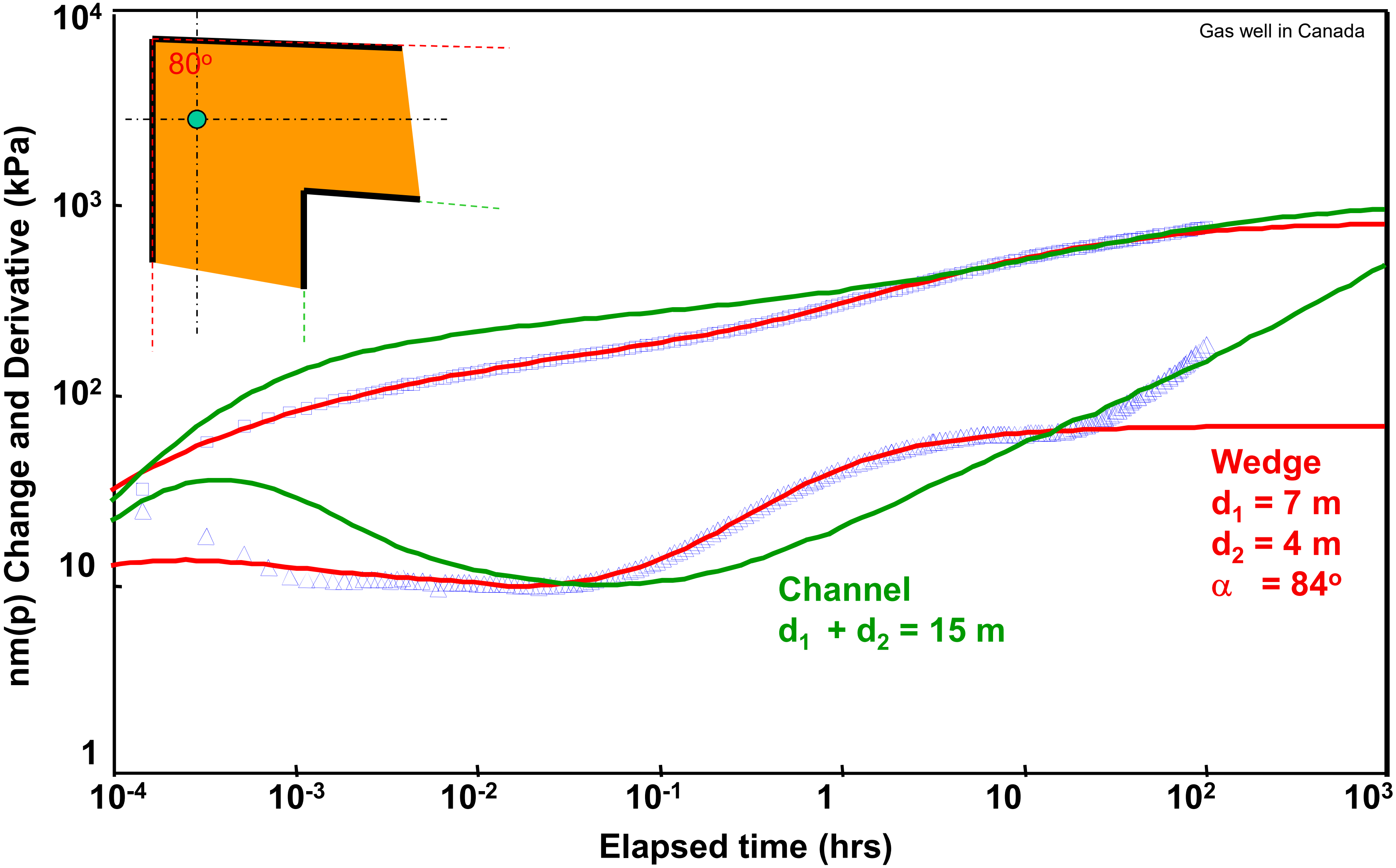






SPE 113877 Mijinyawa R. and Gringarten, A.

MEANDERING CHANNEL



GAS ANALYSIS

p_D: solution to the diffusivity equation

DIFFUSIVITY EQUATION

- linear for oil (single phase)
- non-linear for gas or multiphase

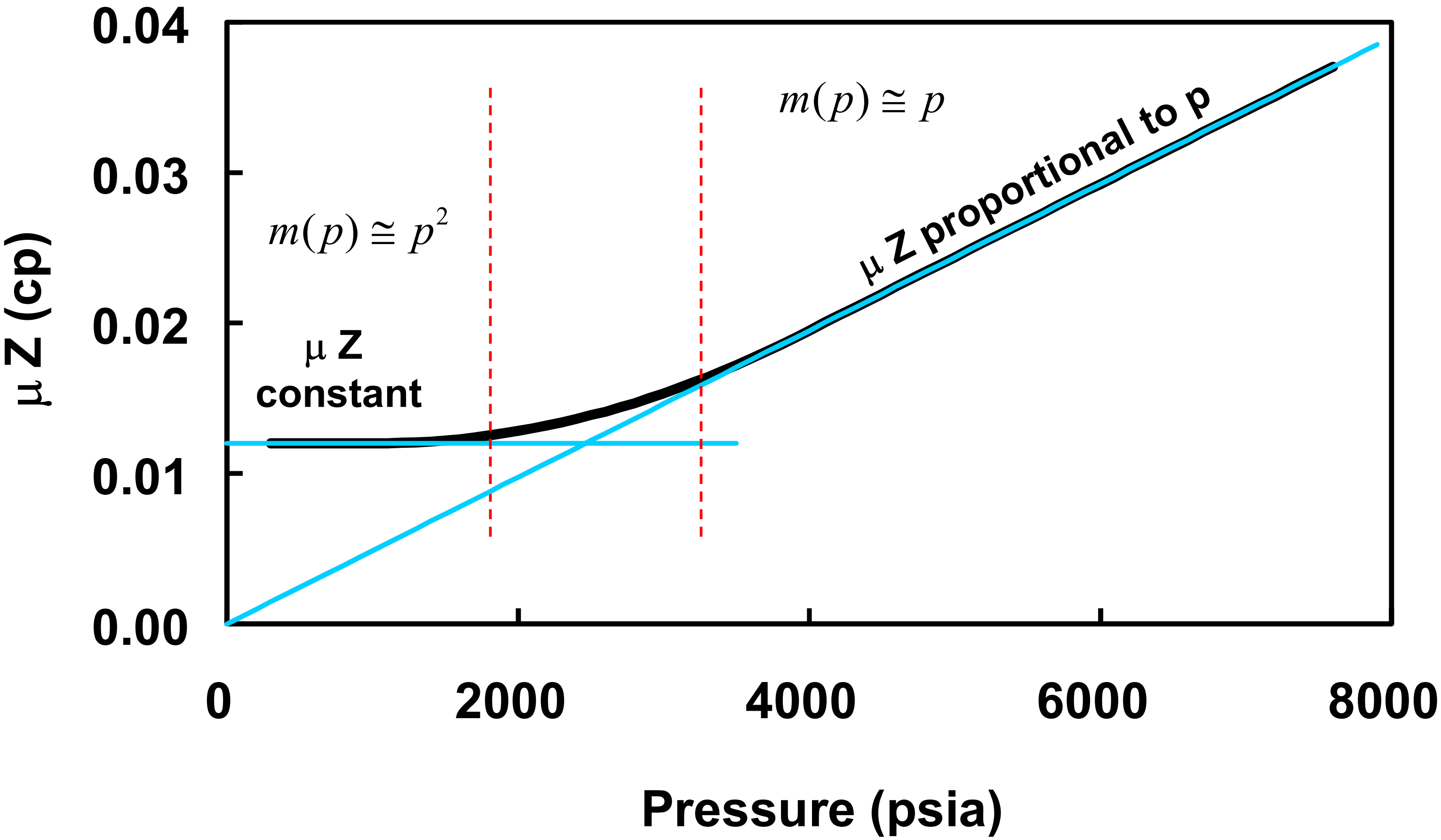
LINEARISATION OF THE DIFFUSIVITY EQUATION

- gas pseudo-pressure (real gas potential)

$$m(p) = 2\int_{p_0}^{p} \frac{p}{\mu(p)z(p)}dp \qquad p_0 = 1\,atm$$

GAS ANALYSIS

$$m(p) = 2\int_{p_0}^{p} \frac{p}{\mu(p)\,z(p)}\,dp \qquad \text{psi}^2/\text{cp}$$



GAS ANALYSIS

Normalised Pseudo-Pressure

$$m_n(p) = \left(\frac{\mu Z}{2p}\right)_{p_i} \int_{p_0}^{p} \frac{2p}{\mu(p)z(p)} dp$$ **psi** →

p = 4000 psi

$m_n(p)$ = 2000 psi

m(p) = 10^9 psi^2/cp

Well Test Analysis

$$p_D = \frac{1}{50300} \frac{kh}{Tq_{sc}} \frac{T_{sc}}{p_{sc}} \{m[p(\Delta t)] - m[p(\Delta t = 0)]\}$$

$$p_D = \frac{kh}{141.2[q_{sc}B]\mu} \{m_n[p(\Delta t)] - m_n[p(\Delta t = 0)]\}$$

[$q_{sc}B$] in Bbl/D with q_{sc} in MScf/D and *B* in RBbl/MScf

GAS ANALYSIS

Pseudo-Time

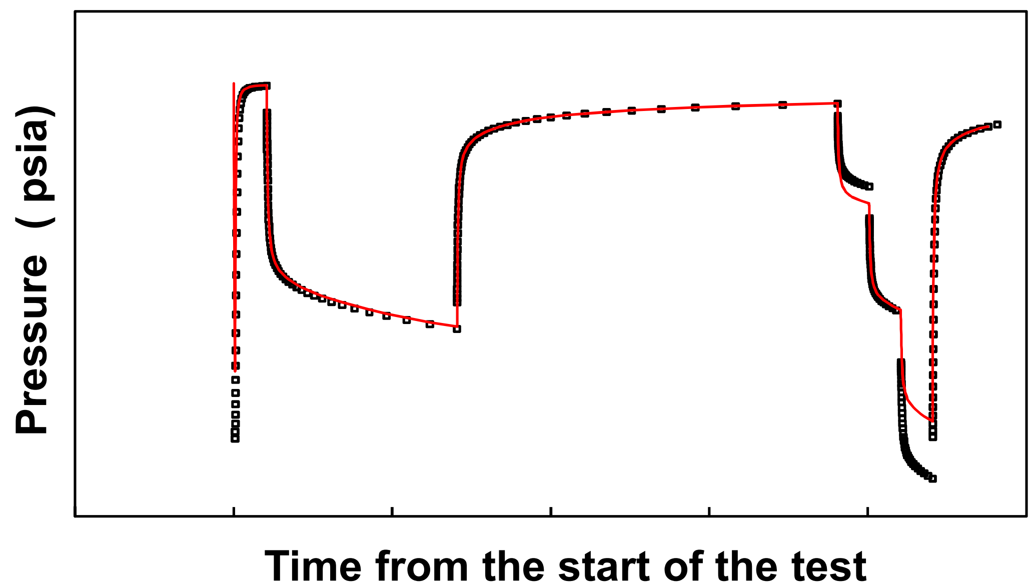
$$t_{ps}(p) = \int_{t_0}^{t} \frac{dt(p)}{\mu(t)\, c_t(t)}$$

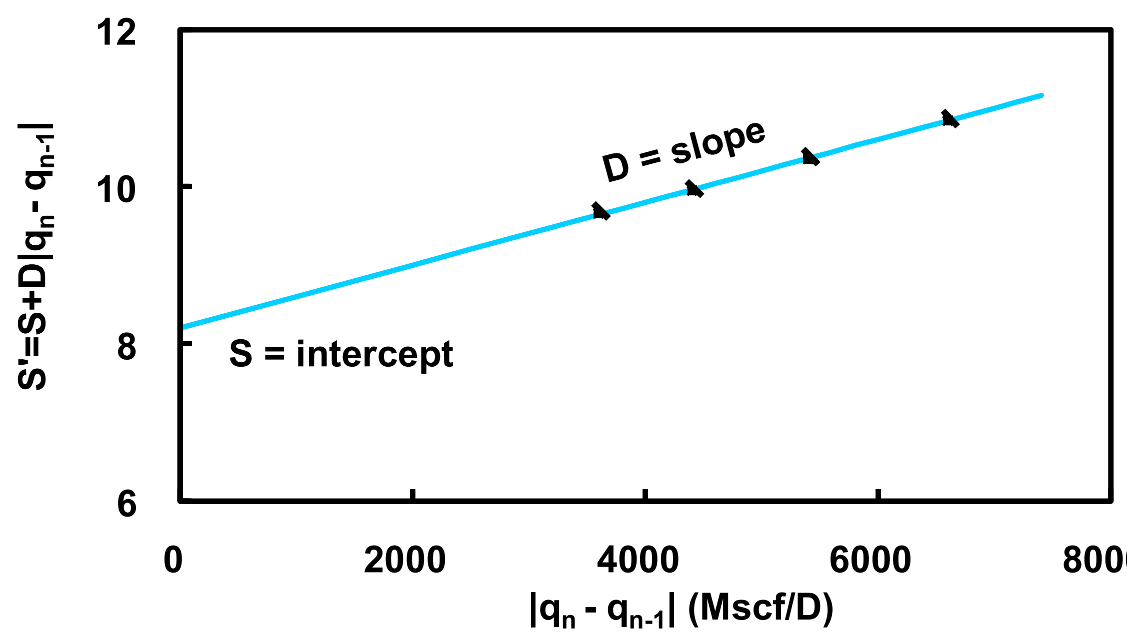
$$= \int_{p_0}^{p} \frac{dt / dp}{\mu(p) c_t(p)}\, dp$$

Normalised Pseudo-Time

$$t_{ps}(p) = (\mu\, c_t)_{\overline{p}} \int_{p_0}^{p} \frac{dt / dp}{\mu(p) c_t(p)}\, dp$$

$$S' = S + Dq_{sc}$$


Pressure (psia)
Time from the start of the test


12
10
8
6
0
2000
4000
6000
8000
S'=S+D|q_n - q_{n-1}|
|q_n - q_{n-1}| (Mscf/D)
D = slope
S = intercept

MATERIAL BALANCE CORRECTION (SPE 36820)

During a reservoir limit test, the average pressure can be estimated with the usual material balance relationship:

$$\frac{\bar{p}}{\bar{z}} = \frac{p_i}{z_i}\left(1 - \frac{G_p}{G_i}\right) \qquad \rightarrow m(\bar{p})$$

where Gi is initial gas volume and Gp the cumulative gas production.

The pseudo-steady state equation:

$$p_D = 2\pi \frac{r_{we}^2}{A} t_{DA} + 1.151\left[\log\frac{A}{r_{we}^2} - \log C_A + 0.786\right]$$

yields a different average pressure:

$$m(\bar{p}_{pp}) = m(p_i) - 2.349\frac{Tq_{sc}}{\phi\mu_i c_{ti} hA}\Delta t \quad = \quad m(p_i) - 2.349\frac{T}{\phi\mu_i c_{ti} hA} G_p$$

Must correct the analytical model by $m(\bar{p}) - m(\bar{p}_{pp})$

MULTIPHASE FLOW ANALYSIS

Perrine, R.L.: "Analysis of Pressure Build-Up Curves," Drill. and Prod. Prac., API (1956) 482.

Martin, John C.: "Theoretical Foundation of Multiphase Pressure Buildup Analysis," J. Pet. Tech. (Oct. 1959) 321-323.

TOTAL EQUIVALENT RATE:

$$(q\,B_t) = q_o B_o + q_w B_w + q_g B_g \qquad (B_t) = B \text{ of dominant phase, vol/vol}$$

$$= q_o B_o + q_w B_w + \left(q_{sg} - q_o R_{so} - q_w R_{sw}\right) B_g$$

RB/D — RB/D — RB/D — scf/D — scf/STB — RB/scf

YIELDS TOTAL MOBILITY: $(k/\mu)_t = k_o/\mu_o + k_w/\mu_w + k_g/\mu_g$

$$(k/\mu)_i = (k/\mu)_t \frac{(qB)_i}{(qB)_t},\ i = o \text{ or } w$$

$$(k/\mu)_g = (k/\mu)_t \frac{\left(q_{sg} - q_o R_{so} - q_w R_{sw}\right) B_g}{(qB)_t}$$

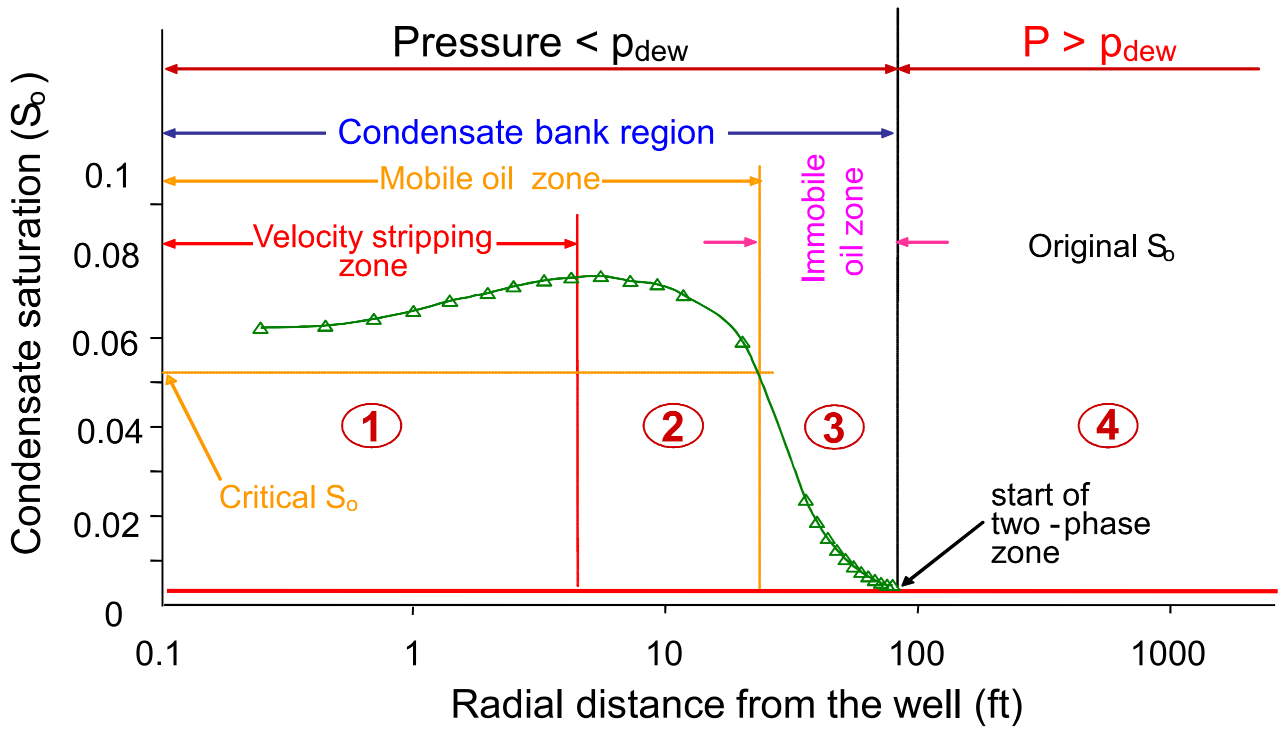
if no gas in reservoir : $\left(q_{sg} - q_o R_{so} - q_w R_{sw}\right) = 0$

ASSUMPTIONS:

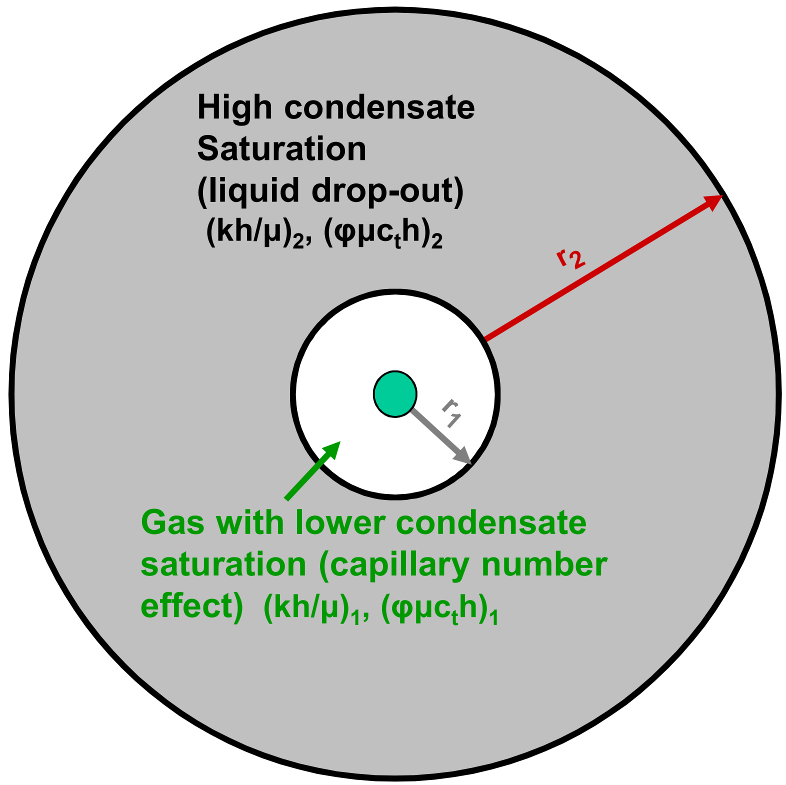
- Phases uniformly distributed in the reservoir
- Saturations constant and independent of pressure
- Capillary pressures neglected (pressure is the same in the different phases)

Well tests in volatile oil and gas condensate reservoirs

Well tests in volatile oil and gas condensate reservoirs below the saturation pressure are usually difficult to interpret because of the gas or condensate bank formation at the wellbore (Gringarten et al., 2006)

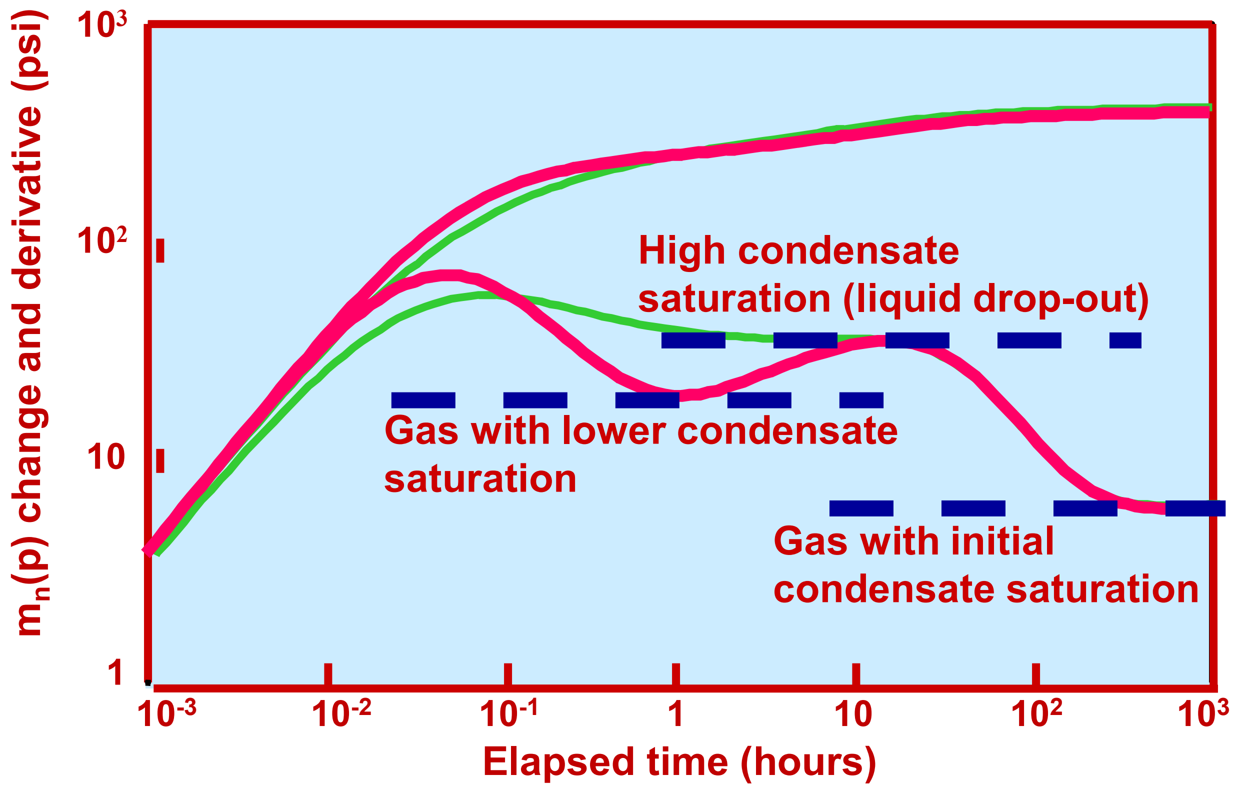


Capillary number effect on condensate bank

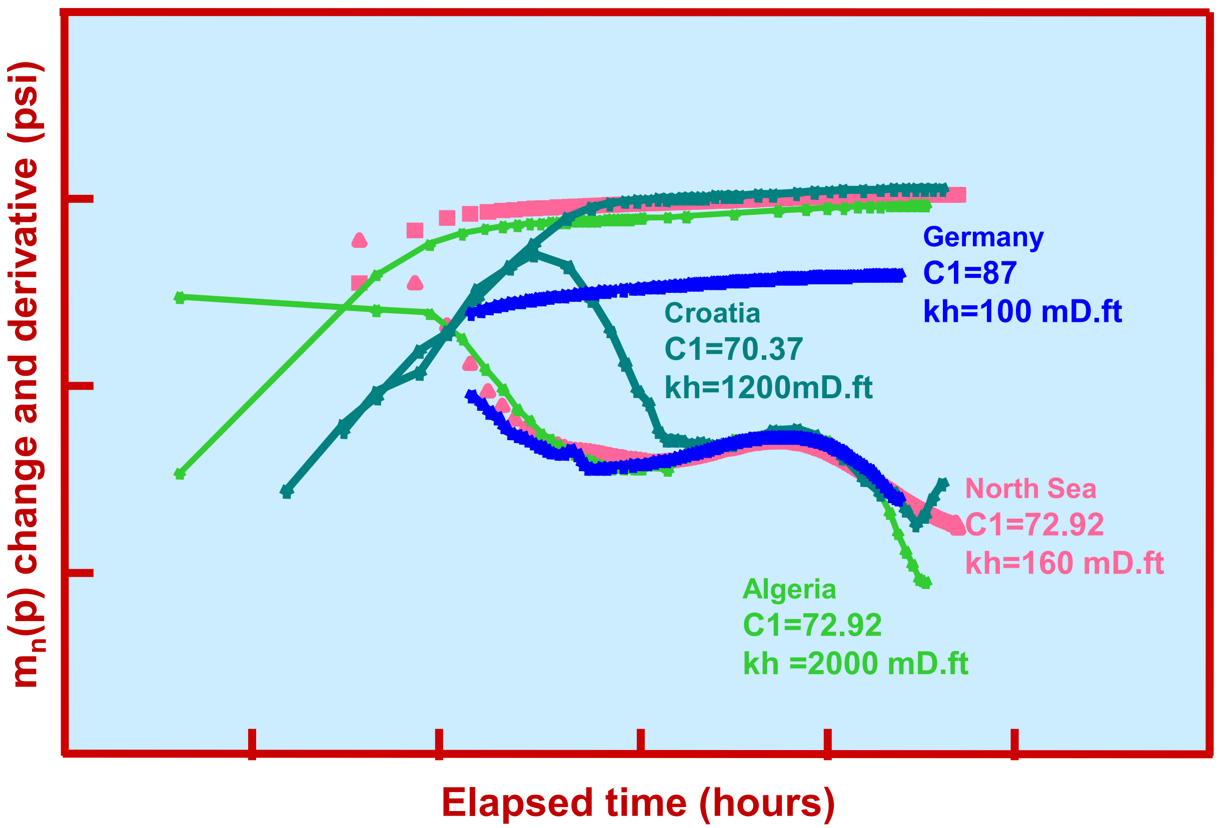


Gas with Initial
Condensate
Saturation

3- Region composite behavior

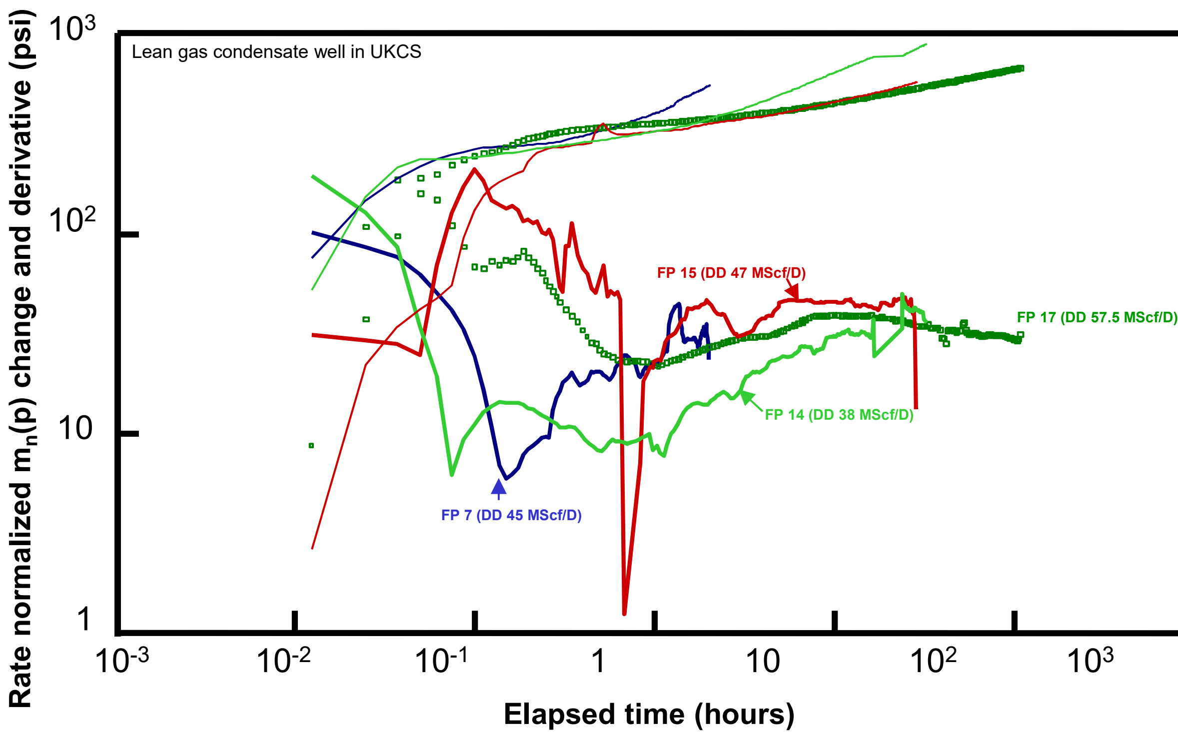


Example of 3-Region composite behaviors



Wellbore storage increases due to phase redistribution in the well:

gas condensate well



METHODOLOGY

- **Numerical compositional simulation**
  - ❑ To generate synthetic multi-rate well test data including capillary number and non-Darcy flow effects

- **Well test analysis**
  - ❑ Single-phase pseudo-pressure formulation
    - To assess the impact of capillary number and inertia effects on the skin factor
    - To estimate skin due to presence of second phase
  - ❑ Two-phase pseudo-pressure formulation
    - To eliminate two-phase flow effect on the skin

Gas-Condensate Well Test Analysis

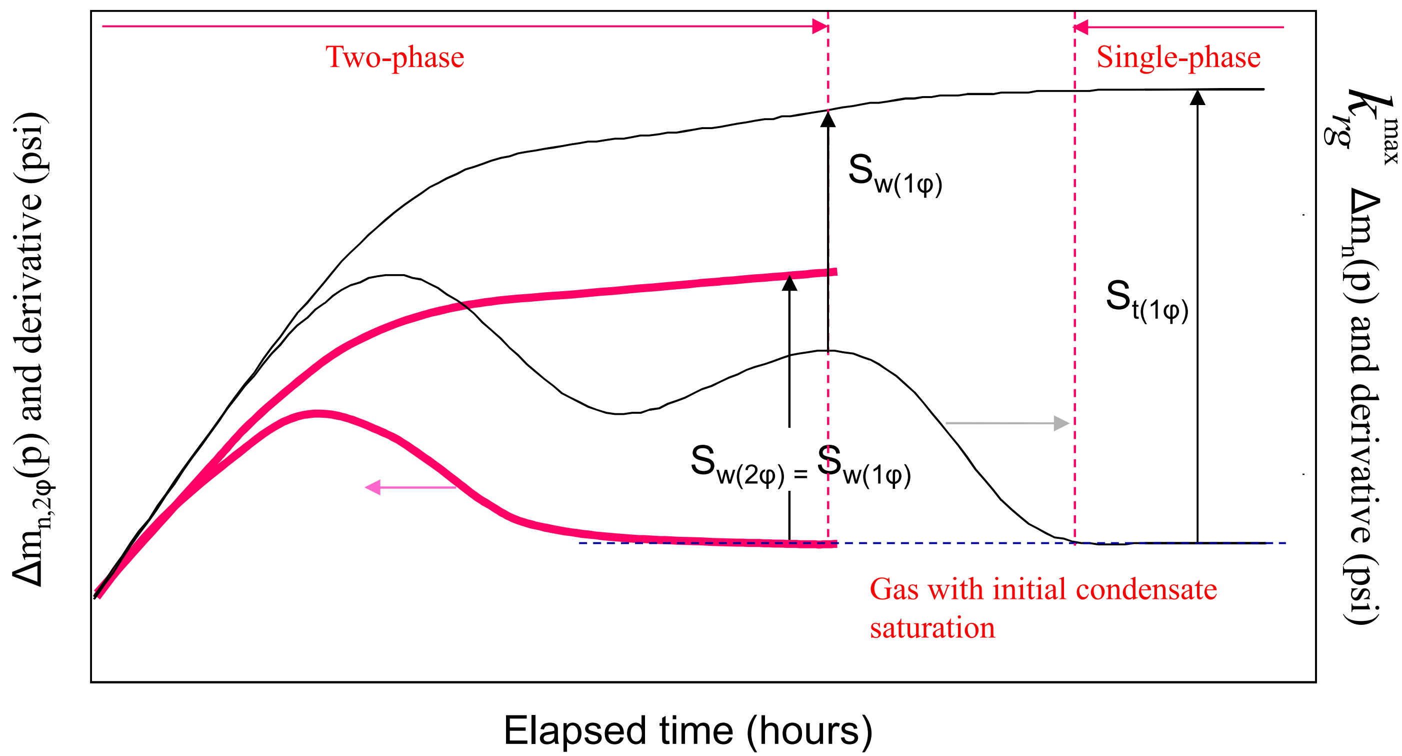
- **Single-phase pseudo-pressure (real gas potential)**
  accounts for the variation of fluid properties with pressure

$$m_{(1-\varphi)} = 2\int_{p_0}^{p} \frac{p}{\mu(p)Z(p)}dp$$

- **Two-phase steady-state pseudo-pressure (real gas potential)**
  accounts for the variation of fluid properties and relative permeability with pressure (single fluid equivalent)

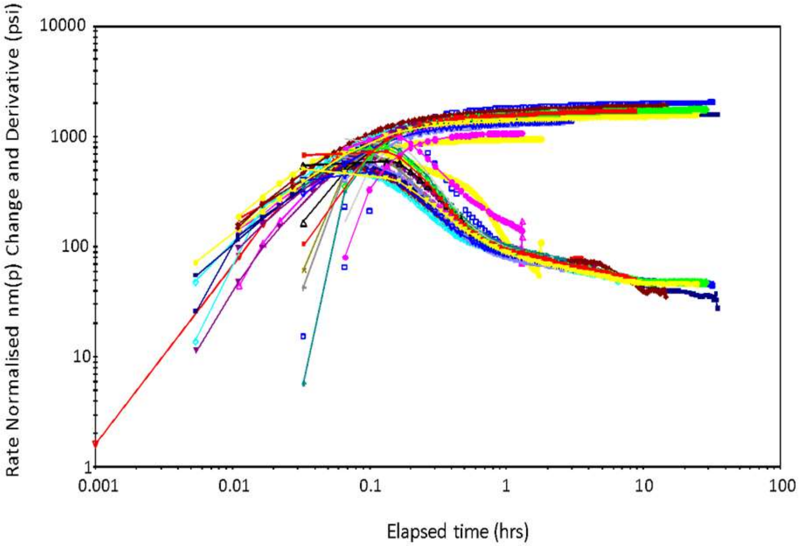
$$m_{(2-\varphi)} = 2\int_{p_0}^{p} \left(\frac{R_s k_{ro}}{\mu_o B_o} + \frac{k_{rg}}{\mu_g B_g}\right)dp$$

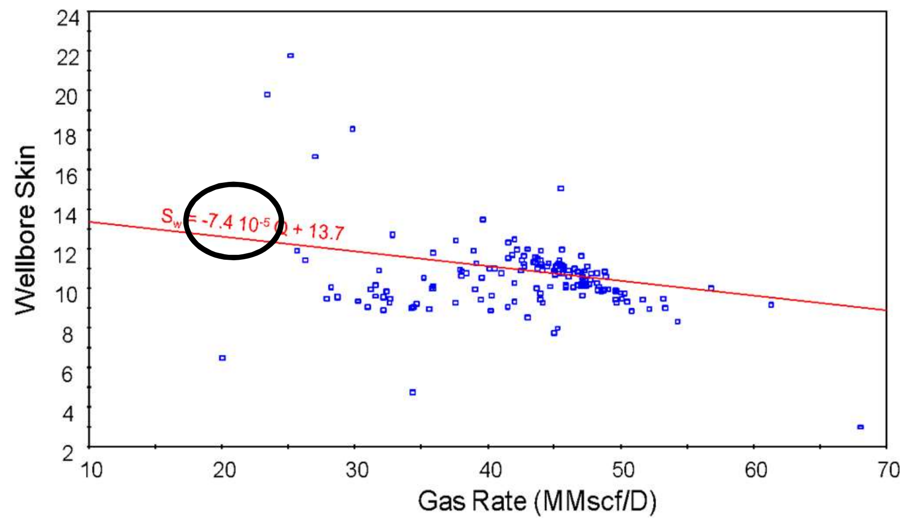
Gas-Condensate Well Test Analysis



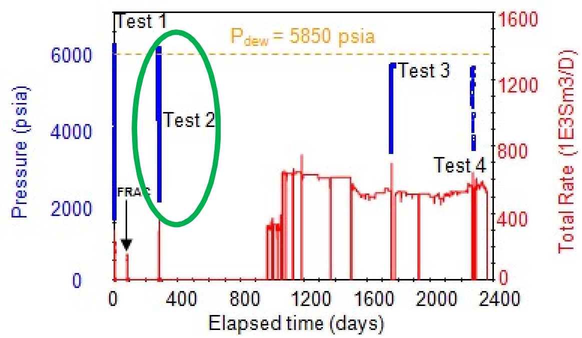
Gringarten *et al.*: "Well Test Analysis in Lean Gas Condensate Reservoirs: Theory and Practice", *SPE 100993 (2006)*

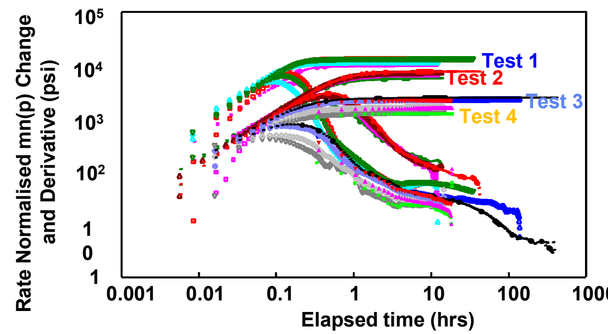
Lean gas condensate, North Sea

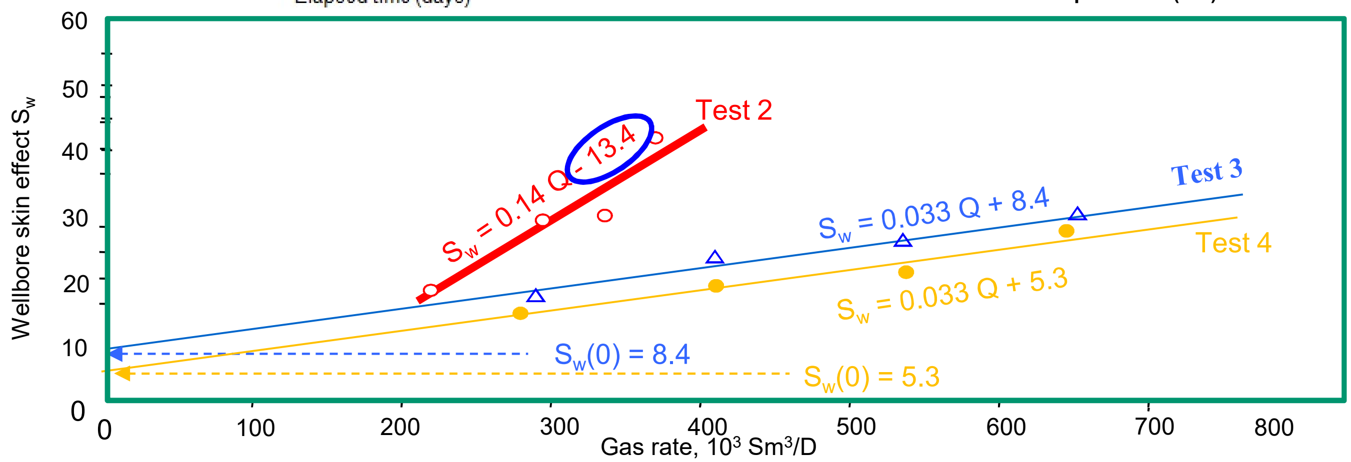




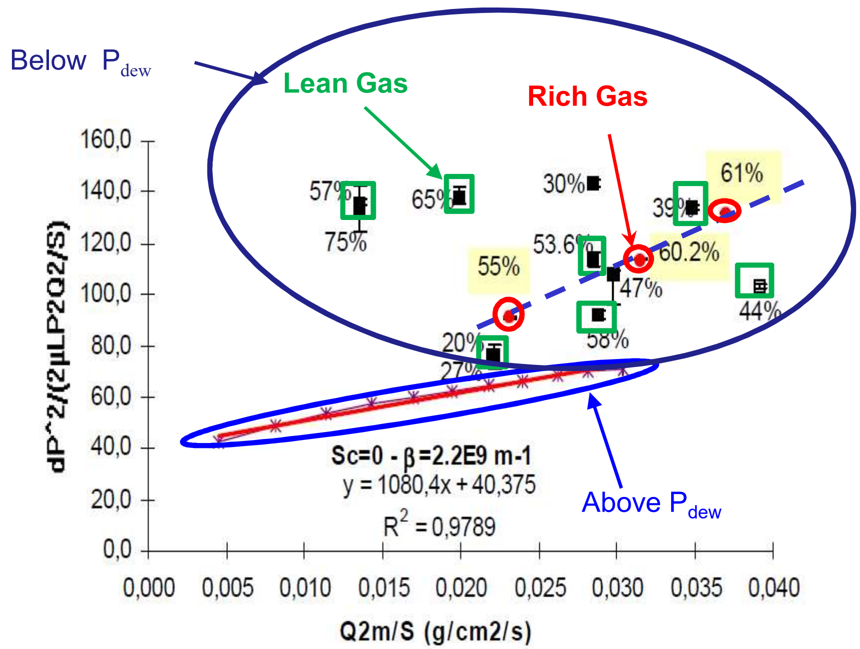
Rich gas condensate, Algeria

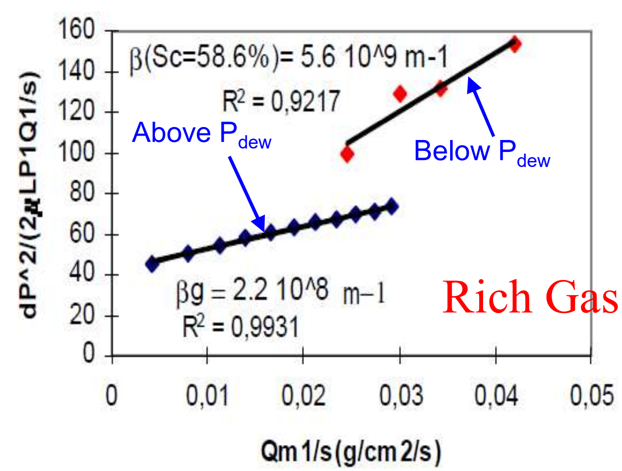






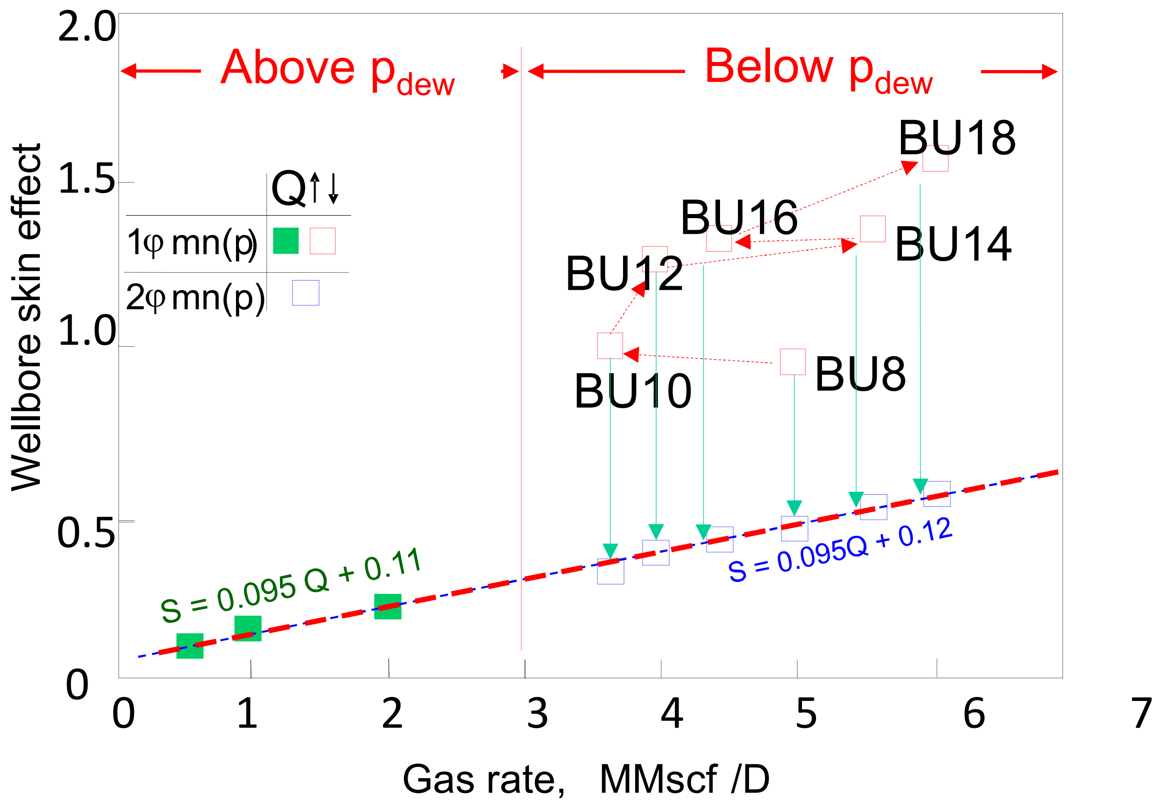
Experimental study- Forchheimer Diagram (lean and rich gases)



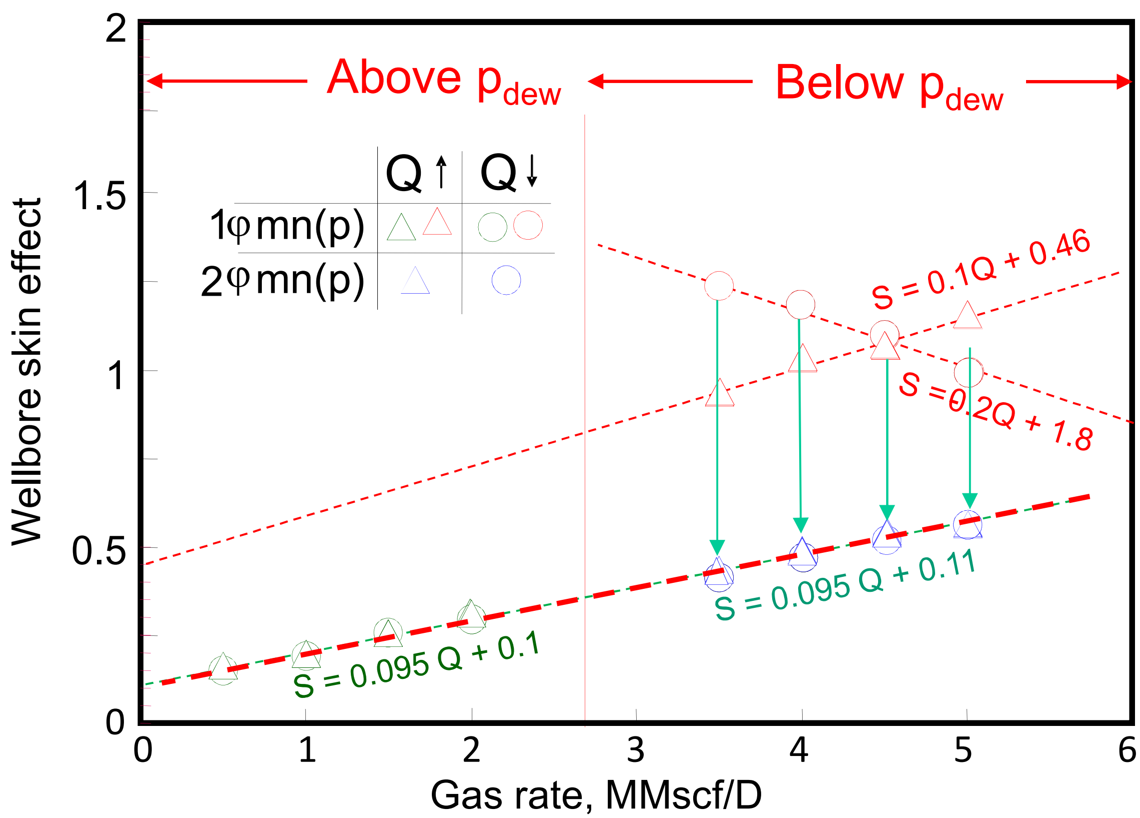


Lombard *et al.:"* Influence of connate water and condensate saturation on inertial effects in gas-condensate fields", *SPE* 56485 *(1999) and SPE 65430 (2000)*

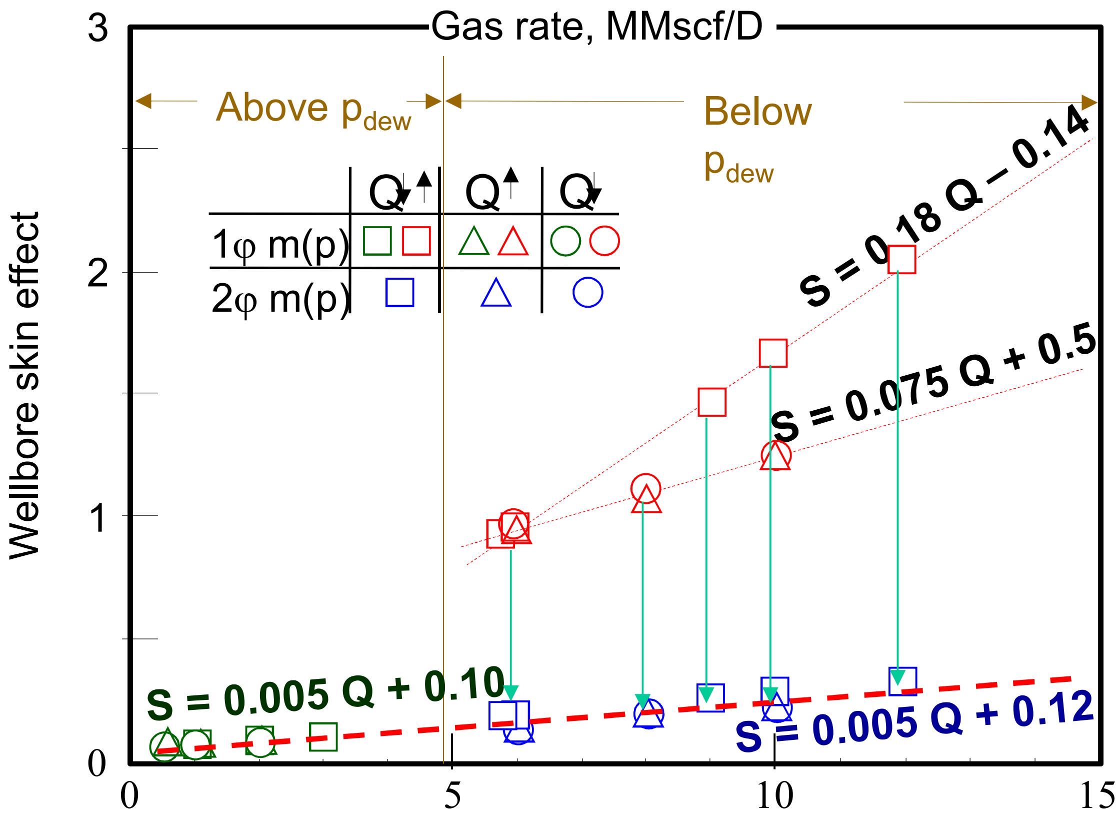
Lean Gas (random rate-1φ and 2φPP)



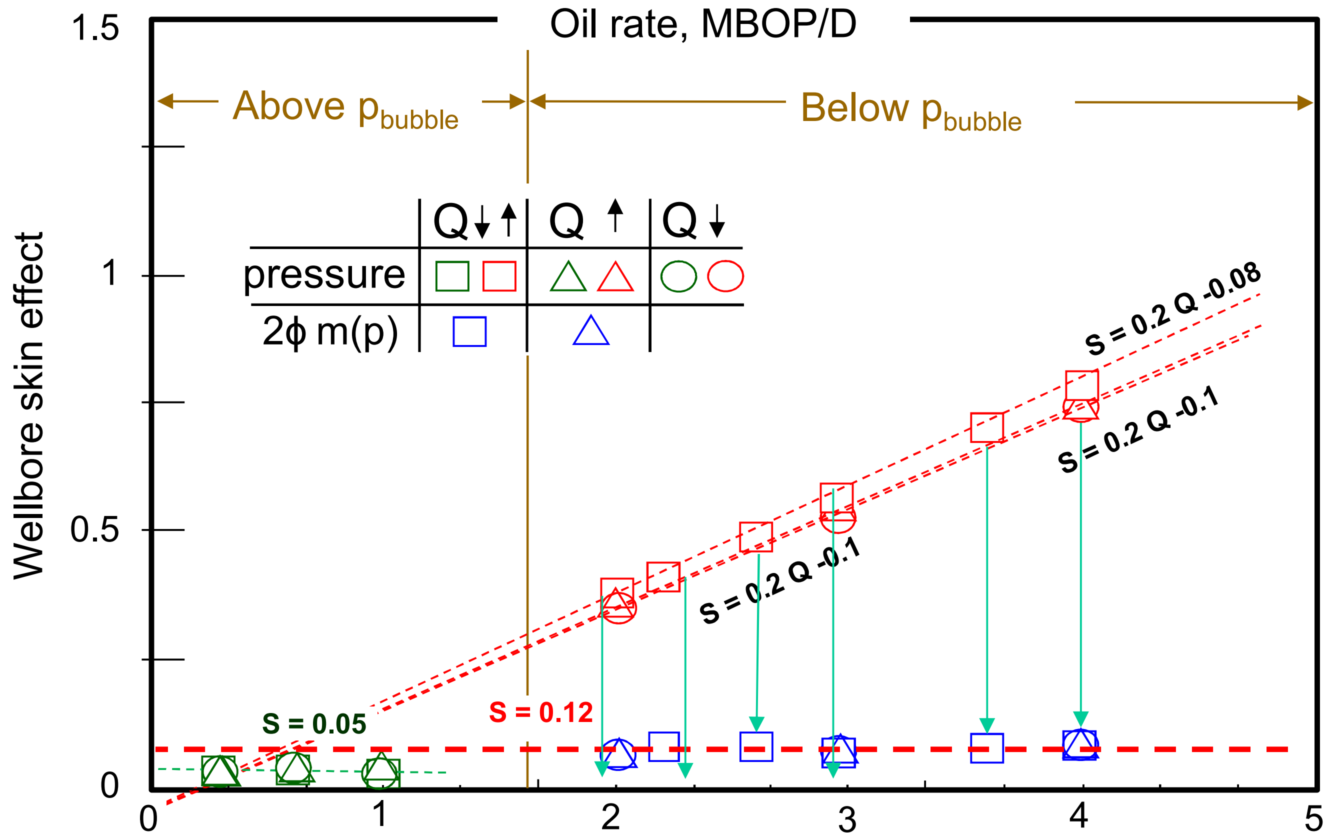
Lean Gas (Increasing and Decreasing rate-1ϕ and 2ϕPP)



Rich Gas p_{dew}= 4835 psia (1ϕ and 2ϕPP)



Volatile Oil p_{bubble}= 4474 psia (Pressure and 2φPP)



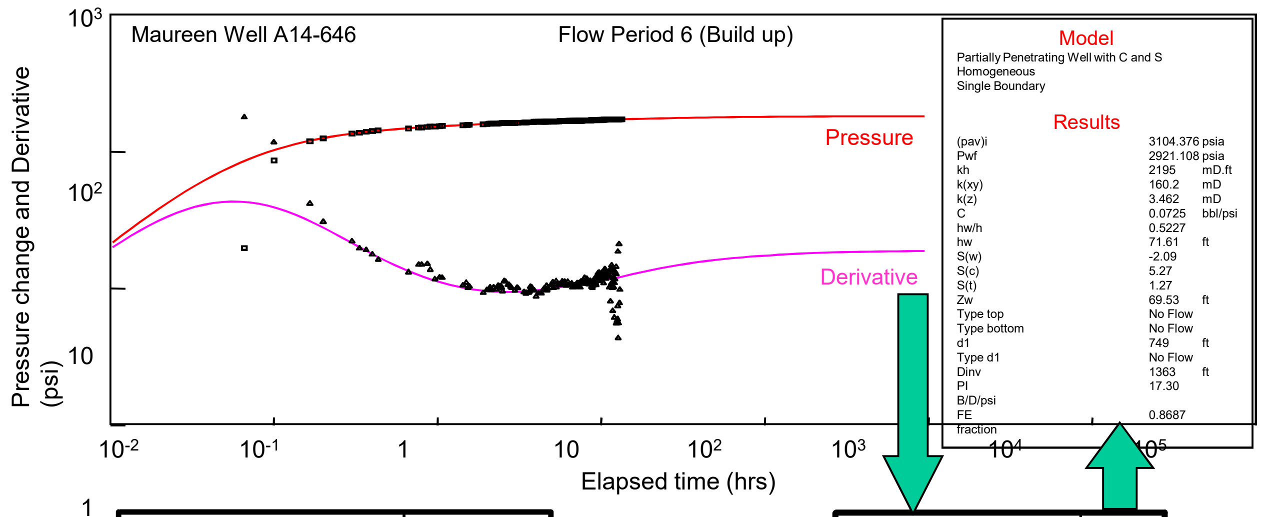
Uncertainties in interpretation results

Evaluation of confidence intervals in well test interpretation results

1. errors in pressure and rate measurements
2. uncertainties in basic well and reservoir parameters
3. quality of the match with the interpretation model
4. non-uniqueness of the interpretation model

SPE 113888 Azi, A., Gbo, A., Whittle, T. and Gringarten, A.

Evaluation of confidence intervals in well test interpretation results



Input Parameters	Values
Flow rate (q) (Bbl/D)	3.17E+03
FVF (B)	1.26
Viscosity (μ) (cp)	0.74
Porosity (ϕ)	0.25
Total compressibility (c_t) (1/psi)	3.70E-06
Reservoir thickness (h) (ft)	137
Well radius (r_w) (ft)	0.354

Dimensionless parameters	Values
Pressure Match (PM) (1/psi)	0.05260
Time Match (TM) (1/hr)	120.7
$(LogC_De^{2s})_{match}$	1.794
$(C_De^{2s})_{match}$	62.23
$(h_D^2/C_D)_{match}$	1699.2
$(zw_D)_{match}$	0.5075
$(hw_D)_{match}$	0.5227
$(d_1)_D$	4394

Errors in input data

Static data	pdf	Percentage of error	
		Corrected for errors with logs	Not corrected for errors with logs
ϕ	Normal	15 % standard deviation	5 % standard deviation
h	Triangular	50 % error	15% error
r_w	Triangular	10 % error	10 % error

		Above bubble point	Below bubble point
B	Uniform	10 % error	5 % error
μ	Uniform	5 % error	5 % error
c_o	Uniform	Accuracy good near bubble point	10 % above 500 psi
		50 % low at high pressure	20 % below 500 psi
q	Normal	10 % standard deviation	

Spivey and Pursell (1998)

Evaluation of confidence intervals in well test interpretation results

Uncertainties in basic well and reservoir parameters

Assumption: Viscosity, u

Uniform distribution with parameters:

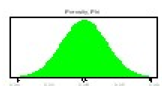
Minimum	0.70
Maximum	0.78

Mean value in simulation was 0.74

Assumption: Porosity, Phi

Normal distribution with parameters:

Mean	0.25
Standard Dev.	0.01

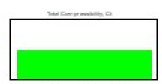


Selected range is from -Infinity to +Infinity
Mean value in simulation was 0.25

Assumption: Total Compressibility, Ct

Uniform distribution with parameters:

Minimum	1.85E-06
Maximum	3.70E-06

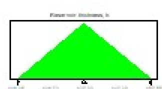


Mean value in simulation was 2.77E-6

Assumption: Reservoir thickness, h

Triangular distribution with parameters:

Minimum	116.45
Likeliest	137.00
Maximum	157.55

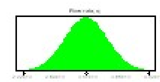


Selected range is from 116.45 to 157.55
Mean value in simulation was 136.83

Assumption: Flow rate, q

Normal distribution with parameters:

Mean	3.17E+03
Standard Dev.	3.17E+02

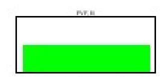


Selected range is from -Infinity to +Infinity
Mean value in simulation was 3.17E+3

Assumption: FVF, B

Uniform distribution with parameters:

Minimum	1.13
Maximum	1.39

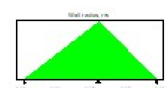


Mean value in simulation was 1.26

Assumption: Well radius, rw

Triangular distribution with parameters:

Minimum	0.32
Likeliest	0.35
Maximum	0.39



Selected range is from 0.32 to 0.39
Mean value in simulation was 0.35

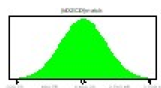
Evaluation of confidence intervals in well test interpretation results

Quality of the match with the interpretation model

Assumption: (hD2/CD)match

Normal distribution with parameters:
Mean 1,699.20
Standard Dev. 676.30

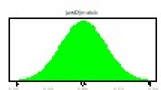
Selected range is from -Infinity to +Infinity
Mean value in simulation was 1,696.27



Assumption: (zwD)match

Normal distribution with parameters:
Mean 0.51
Standard Dev. 0.15

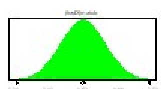
Selected range is from -Infinity to +Infinity
Mean value in simulation was 0.51



Assumption: (hwD)match

Normal distribution with parameters:
Mean 0.52
Standard Dev. 0.06

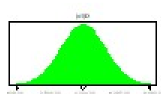
Selected range is from -Infinity to +Infinity
Mean value in simulation was 0.52



Assumption: (d1)D

Normal distribution with parameters:
Mean 4,394.00
Standard Dev. 1,262.00

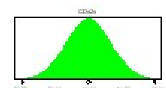
Selected range is from -Infinity to +Infinity
Mean value in simulation was 4,403.74



Assumption: CDe2s

Normal distribution with parameters:
Mean 62.23
Standard Dev. 1.56

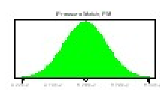
Selected range is from -Infinity to +Infinity
Mean value in simulation was 62.23



Assumption: Pressure Match, PM

Normal distribution with parameters:
Mean 5.26E-02
Standard Dev. 3.47E-03

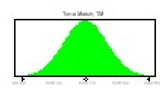
Selected range is from -Infinity to +Infinity
Mean value in simulation was 5.26E-2



Assumption: Time Match, TM

Normal distribution with parameters:
Mean 120.70
Standard Dev. 9.60

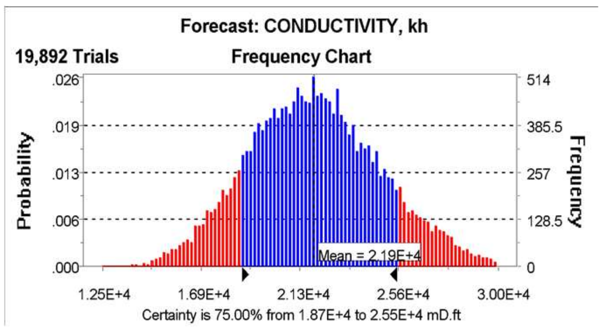
Selected range is from -Infinity to +Infinity
Mean value in simulation was 120.71

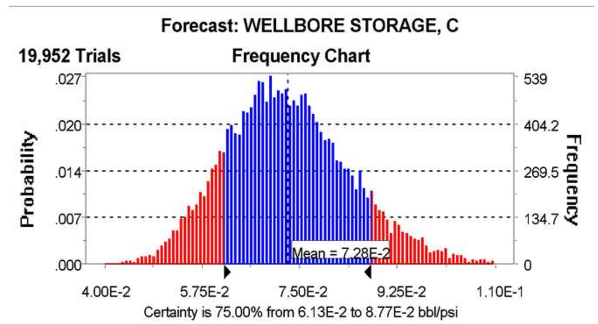


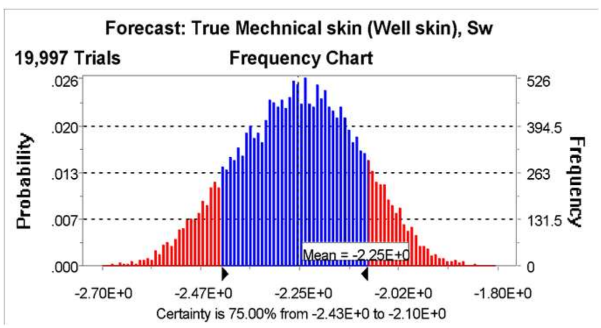
Equivalence between manual and software match uncertainty, for an oil well

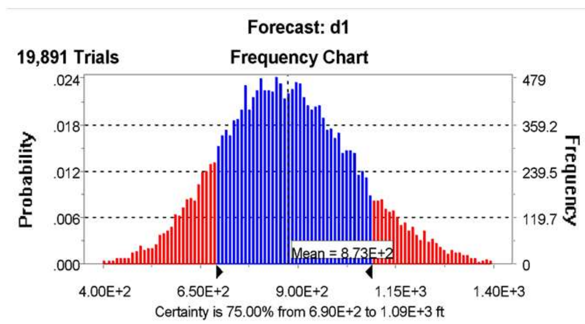
Manual well test results uncertainty		Dimensionless match results uncertainty
kh ±10%	is equivalent to	PM ±13%
C ±10%		TM ±17 %
S ±0.5		C_De^{2S} ±10%
d_i ±30%		$(d_1)_D$ ±13%

Evaluation of confidence intervals in well test interpretation results









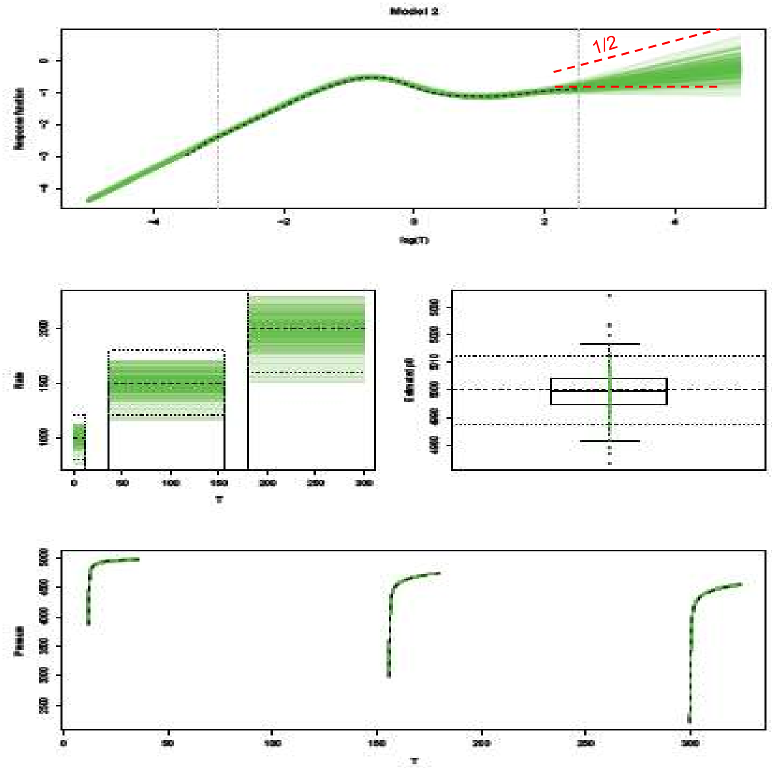
75% probability	Min	Mean	Max
kh (mD.ft)	1870	2190	2550
C (bbl/psi)	6.13E-02	7.28E-02	8.77E-02
S	-2.43	-2.25	-2.1
d (ft)	693	87	1093

75% probability	-	Mean	+
kh (mD.ft)	32	2190	36
C (bbl/psi)	0.011	0.0728	0.0149
S	50.18	-2.25	0.15
d (ft)	183	876	217

75% probability	-	+
kh (mD.ft)	15%	16
C (bbl/psi)	16%	20 %
S	-8%	-7%
d (ft)	21%	25 %

kh	2000	±20%
C	0.07	±20%
S	-2.3	±0.5
d	900	±30%

Uncertainties in deconvolution



TEST DESIGN

TEST OBJECTIVES

The objectives of the test is to determine the characteristics of the well and formation:

- productivity, behaviour
- permeability, skin, initial pressure
- distance to boundaries

while minimizing the duration of the test.

TEST INTENDED SCHEDULE

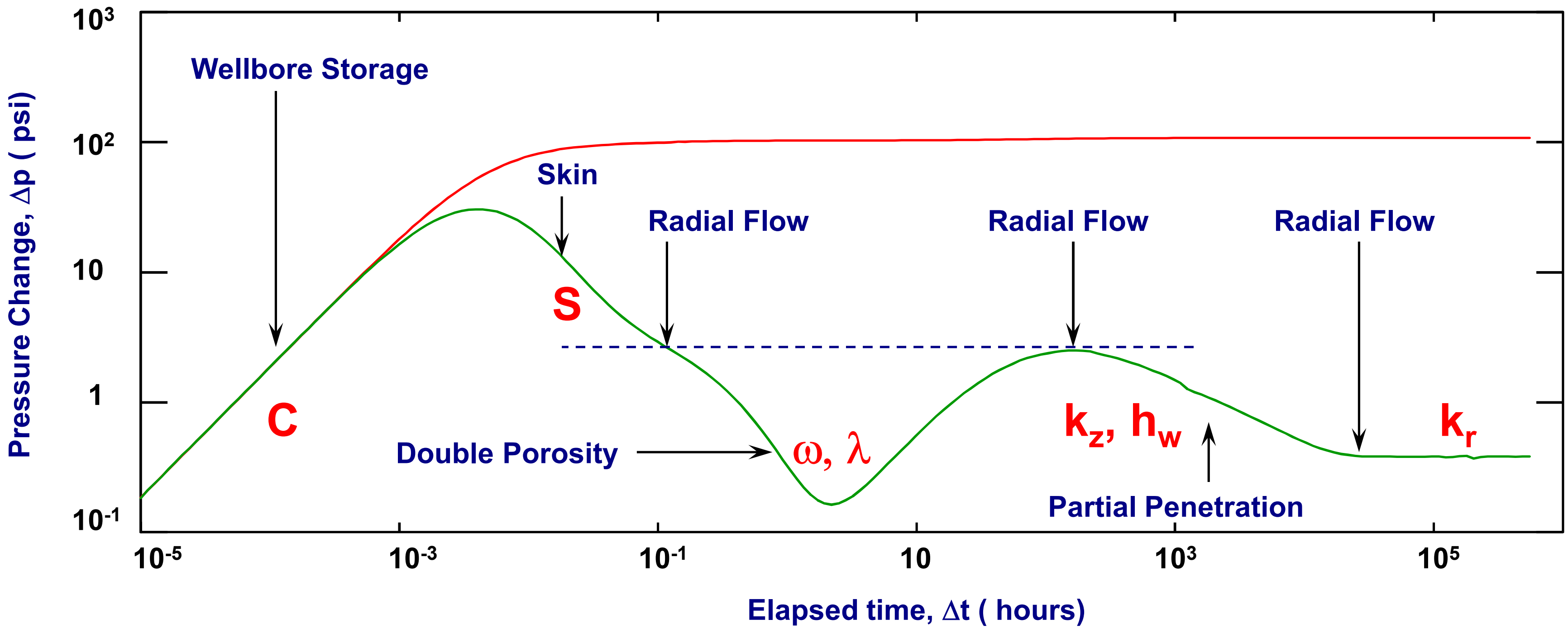
Sequence	Duration	Rate	Results
First flow	2 min.	500 BOPD	
First Build up	1 hour	0	Initial reservoir pressure
Second flow	6 hours	1000 BOPD	
Second Build up	9 hours	0	Behaviour before acid
Acidification	5 hours	0	
Third flow	16 hours	2000 BOPD	
Third Build up	37 hours	0	Behaviour after acid

TEST DESIGN

The well will be partially penetrating a chalk oil reservoir. A double porosity behavior is expected, combined with wellbore storage and skin, and partial penetration.

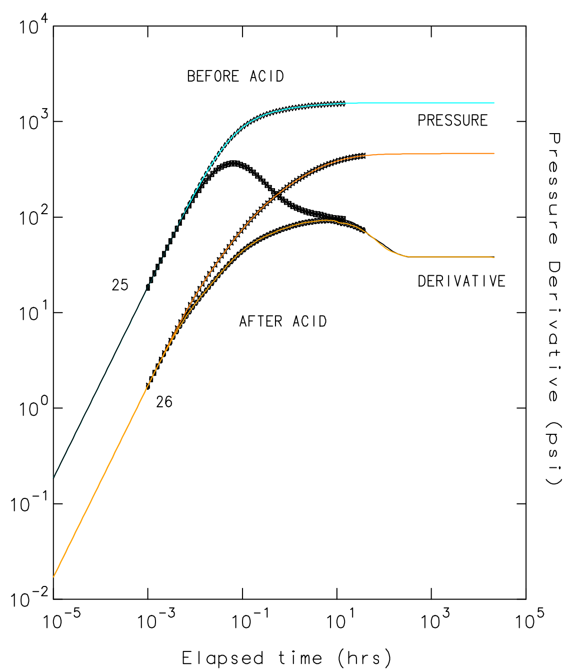
The objective of the design is to predict the likely response of the well and to refine the test schedule within practical limits in order to increase the probability that the test can be interpreted and the desired parameters calculated.

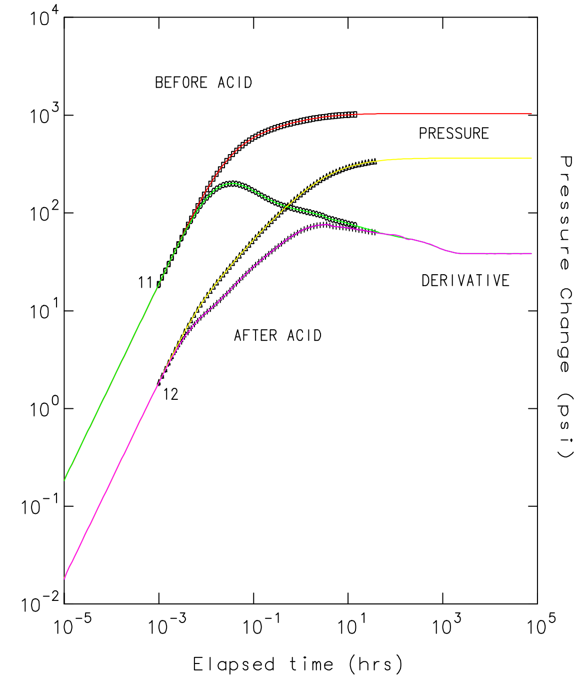
TEST DESIGN

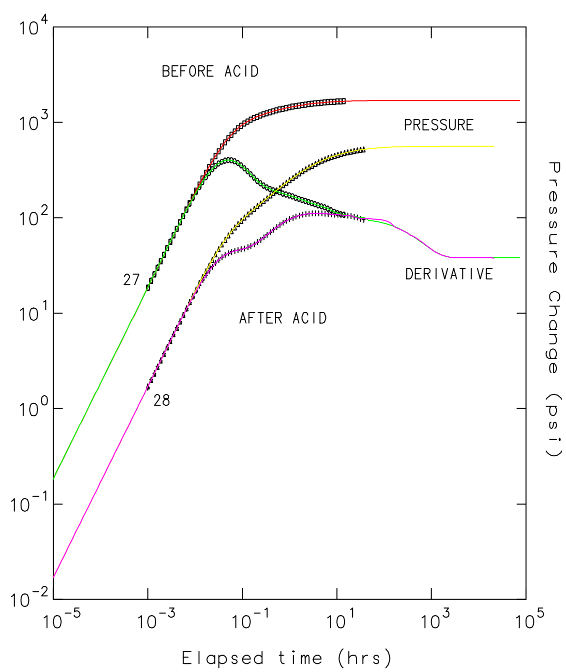


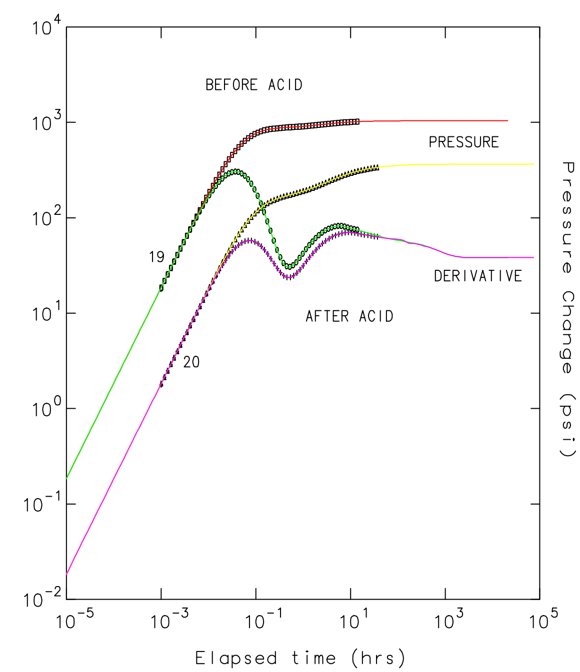
Wellbore Storage
Skin
Radial Flow
Radial Flow
Radial Flow
S
C
Double Porosity
ω, λ
k_z, h_w
k_r
Partial Penetration
10^3
10^2
10
1
10^-1
10^-5
10^-3
10^-1
10
10^3
10^5
Pressure Change, Δp (psi)
Elapsed time, Δt (hours)

	Case #	11	12	13	14	15	16
Fracture permeability, mD	k_f	25	25	25	25	25	25
Matrix permeability, mD	k_m	1	1	1	1	1	1
Well radius, in.	r_w	4.250	4.250	4.250	4.250	4.250	4.250
Formation thickness, ft	h	410	410	410	410	410	410
Perforated interval, ft	h_w	164	164	164	164	164	164
Porosity	ϕ	0.27	0.27	0.27	0.27	0.27	0.27
Bubble point pressure, psi	P_b						
Total Compressibility, psi^{-1}	c_t	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05
Oil compressibility, psi^{-1}	c_o	1.74E-05	1.74E-05	1.74E-05	1.74E-05	1.74E-05	1.74E-05
Oil viscosity, cp	μ_o	2	2	2	2	2	2
OIl formation volume factor, Bbl/Bbl	B_o	1.39	1.39	1.39	1.39	1.39	1.39
Water salinity, ppm	s	200,000	200,000	200,000	200,000	200,000	200,000
Water compressibility, psi^{-1}	c_w	3.30E-06	3.30E-06	3.30E-06	3.30E-06	3.30E-06	3.30E-06
Water viscosity, cp	μ_w	0.6	0.6	0.6	0.6	0.6	0.6
MODEL							
Early times		**WB,S,PP**	**WB,S,PP**	**WB,S,PP**	**WB,S,PP**	**WB,S,PP**	**WB,S,PP**
Reservoir Behavior		**2P**	**2P**	**2P**	**2P**	**2P**	**2P**
Late times		**Infinite**	**Infinite**	**Infinite**	**Infinite**	**Infinite**	**Infinite**
Skin	S	**0**	**-4**	**0**	**-4**	**0**	**-4**
Tubing radius, in.	r_t	2	2	2	2	2	2
Tubing length for downhole shut-in, ft	L	607	607	607	607	607	607
Wellbore storage coefficient, bbl/psi	$C=c_o 2\pi r_t L$	0.006	**0.065**	**0.006**	0.065	0.006	**0.065**
Average length of matrix block, ft	l	3.3	3.3	3.3	3.3	**10.8**	10.8
Dimension order of matrix block	n	3	3	3	3	3	3
Shape factor, ft^{-1}	$\alpha = 4n(n+2)/l^2$	2.7548	2.7548	2.7548	2.7548	0.2559	0.2559
Interporosity coefficient	$\lambda = \alpha r_w^2 k_m/k_f$	1.38E-02	1.38E-02	1.38E-02	1.38E-02	**1.28E-03**	1.28E-03
Storativity ratio	$\omega = (\phi V c_t h)_f/(\phi V c_t h)_{f+m}$	0.01	0.01	0.01	0.01	0.01	0.01
Equivalent reservoir thickness (water>oil),	$h_e = h_w + (h-h_w)sqrt(c_w\mu_w/c_o\mu_o)$	410	410	410	410	410	410
Mid perforation location, ft from bottom	z_w	328	328	328	328	328	328
Vertical permeability, mD	k_z	2.5	2.5	**20**	20	2.5	2.5


BEFORE ACID
PRESSURE
DERIVATIVE
AFTER ACID
25
26
Pressure Derivative (psi)
Elapsed time (hrs)


BEFORE ACID
PRESSURE
DERIVATIVE
AFTER ACID
11
12
Pressure Change (psi)
Elapsed time (hrs)


BEFORE ACID
PRESSURE
DERIVATIVE
AFTER ACID
27
28
Pressure Change (psi)
Elapsed time (hrs)


BEFORE ACID
PRESSURE
DERIVATIVE
AFTER ACID
19
20
Pressure Change (psi)
Elapsed time (hrs)

EXPECTED TEST BEHAVIOUR

- Double porosity BEHAVIOUR will be observed only with 10m and above matrix block dimensions
- Wellbore storage should be observed if early time measurements start at 4 second intervals
- Radial flow in front of the well opening corresponding to $k_r h_w$ should be reached after about 10 hours
- Final radial flow corresponding to $k_r h$ will not be observed during the test. Reaching that radial flow would take approximately 2000 hours if k_z = 2.5 mD and 600 hours if k_z = 20 mD. In other words, the lower reservoir boundary will not be seen during the test.
- At the end of the third drawdown, boundaries will be seen if they are within 80 m (265 ft) from the well
- To help the analysis, a spinner survey should be run to determine the well length open to flow.
- There is no significant additional knowledge to be learned by having the third drawdown last 37 hours as opposed to 16 hours. The duration of that third Build up can be adjusted during the test.
- The analysis will be made more difficult if the pressure around the well drops below the bubble point and if water coning occurs due to vertical fractures.

9 QUESTIONS BEFORE STARTING A WELL TEST ANALYSIS

RESERVOIR QUESTIONS

1) What type of rock?

- ✓ **Expect double porosity behaviour with:**
  - ***limestone***
  - ***carbonate***
  - ***granite***
  - ***basalt***
  - ***unconsolidated sand***
- ✓ **Expect composite behaviour with acidised carbonate (** r_1 **about 3 ft)**
- ✓ **No double porosity behaviour with consolidated sandstone**

2) Is this a layered reservoir?

3) Any known boundary, producing or injecting well near nearby, gas cap, water contact?

9 QUESTIONS BEFORE STARTING A WELL TEST ANALYSIS

WELL QUESTIONS

4) Is the well vertical, slanted or horizontal?

5) How was the well completed?

- *acidised*
- *fractured*
- *limited entry*

✓ **Expect high skins in limited entry wells**

- *on gas lift*

✓ **In gas lift wells, expect increasing wellbore storage effects which may override any reservoir behaviour**

6) How long has the well been in production?

9 QUESTIONS BEFORE STARTING A WELL TEST ANALYSIS

FLUID QUESTIONS

7) What is the dominant phase?

- *oil*
- *gas*
- *water*

8) How many phases?

- *in the wellbore*
- *in the reservoir*

✓ **Expect phase redistribution and increasing wellbore storage if wellbore fluids have different densities**

9) What is the bubble point pressure (oil) or dew point pressure (condensate gas)?

✓ **Expect composite behaviour if pressure falls below the bubble point pressure (oil) or dew point pressure (condensate gas)**

10 CHECKS DURING ANALYSIS

DATA VALIDATION

1) ***Check pressure gauges***
2) ***Check start and end of flow periods***
3) ***Check rate consistency***

MODEL DIAGNOSTIC

4) ***Check time and pressure at start of flow period***
5) ***Check derivative smoothing***
6) ***Remember the answers to the 9 questions***
7) ***use common sense***

MATCHING AND FINAL RESULTS

8) ***Check $(P_{av})_i$ on the simulation***
   - *If different from Horner Match, keep $(P_{av})_i$ from simulation and regress on the other parameters in Horner Match*
   - *If much less than known value, consider adding boundaries to the model*
9) ***Check result consistency between flow periods***
10) ***Use common sense***

List of data required for well test analysis

Pressure and temperature data versus time since the well was first tested
Flow rate data i.e. gas, oil and water production rate since the well was first tested
Reservoir structure map for faults location i.e. from seismic data
Composite logs
Location and production or injection details of other wells near-by
Test report

❑ Basic reservoir data

Initial pressure
Matrix porosity
Reservoir thickness
Wellbore radius
Perforation length
Well deviation angle
Core data, i.e. porosity, permeability, vertical to horizontal permeability ratio
Wireline logs data, i.e. porosity and permeability

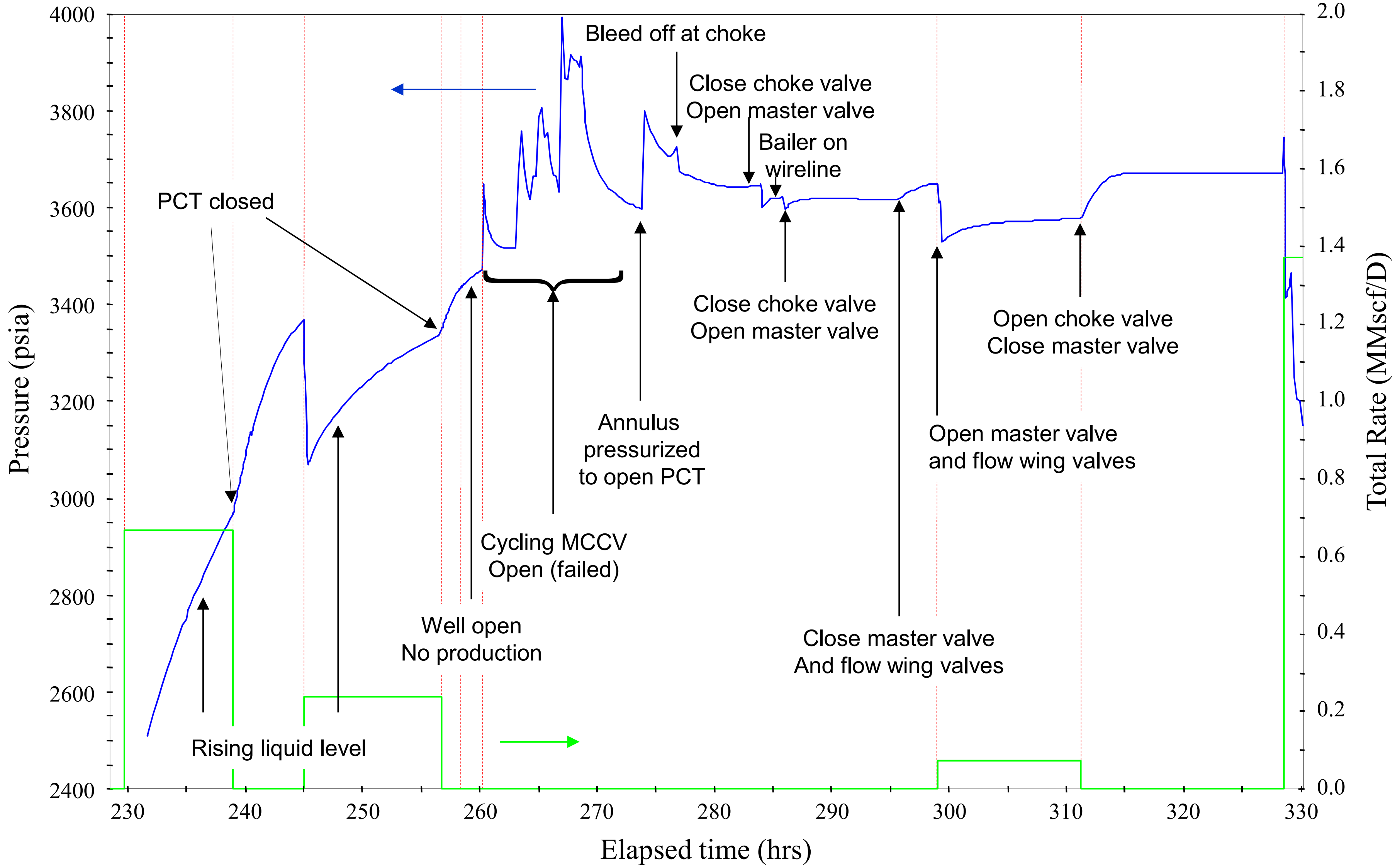
❑ Other data

Gas oil contact
Oil water contact
Three phase relative permeability curves
Reservoir depth
Completion diagram

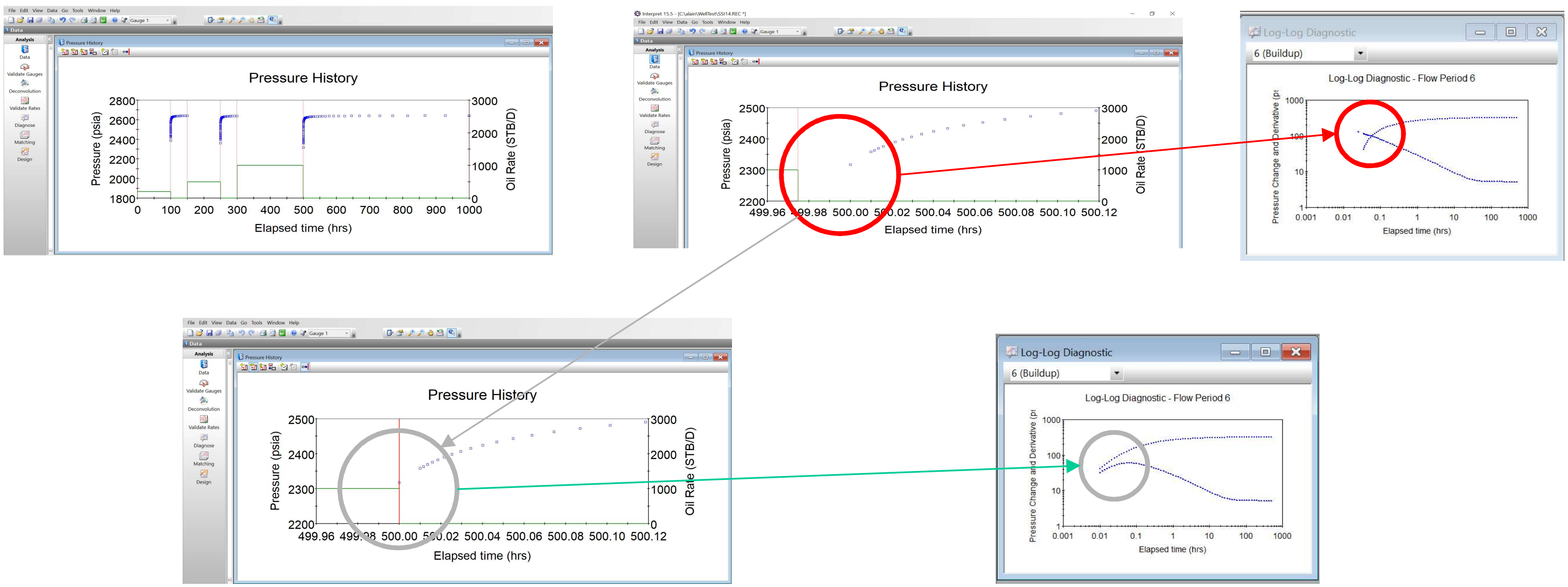
❑ Fluid properties

PVT report
Average reservoir pressure
Average reservoir temperature
Dew point / bubble point pressure
Gas composition or gas specific gravity with CO_2 and H_2S contents
Gas properties, i.e. compressibility, viscosity, formation volume factor, and z factor
Water properties, i.e. compressibility, viscosity, formation volume factor, and water salinity
Oil properties, i.e. compressibility, viscosity, and formation volume factor
CGR, GOR, and/or solution gas water ratio
Total compressibility

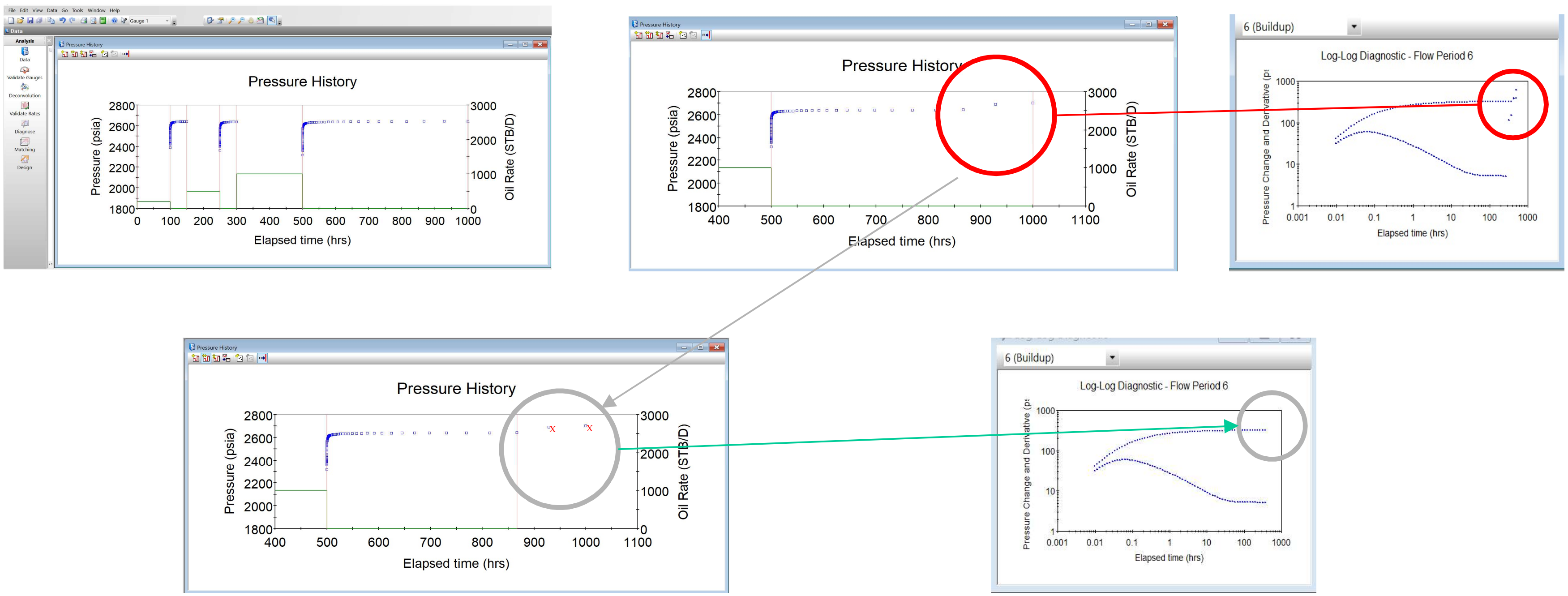
Understanding pressure data



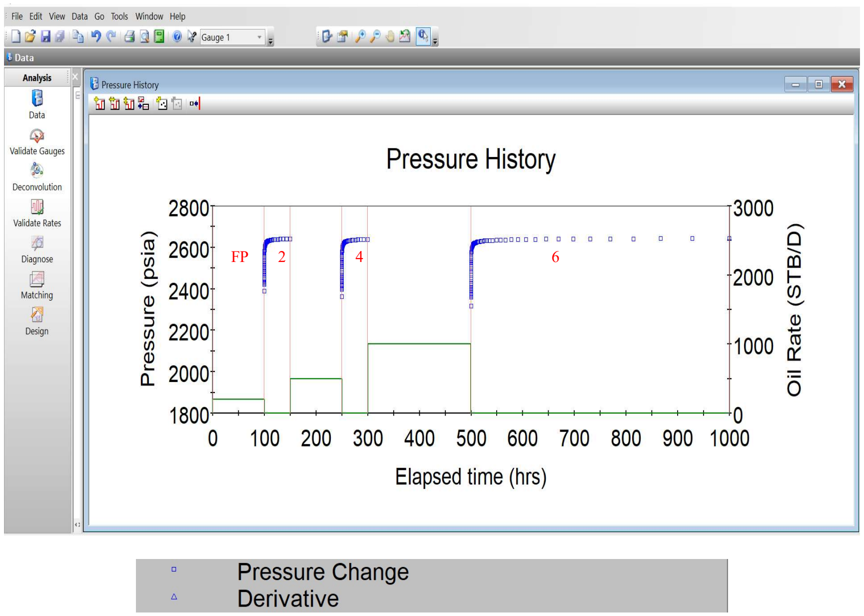
DATA EARLY TIME CORRECTION

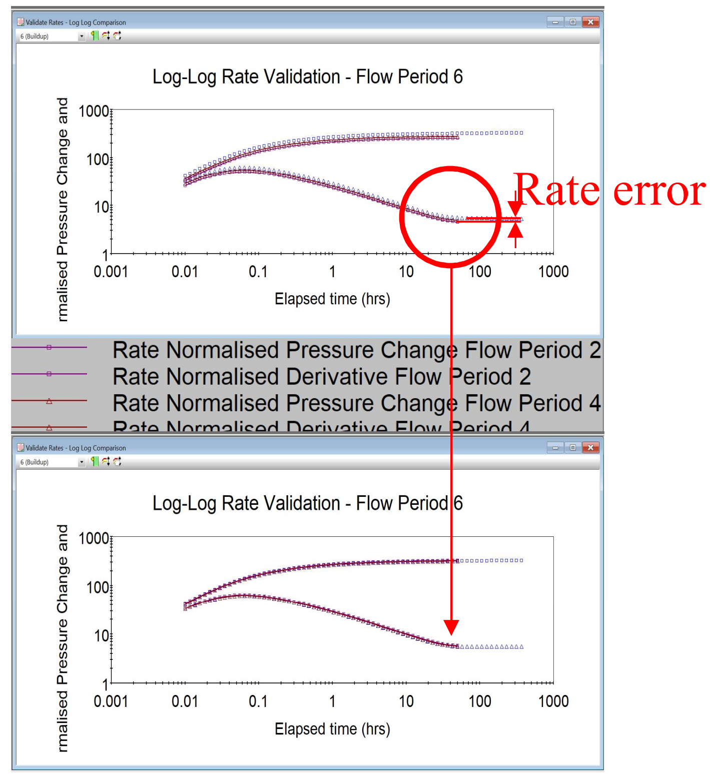


DATA LATE TIME CORRECTION



RATE CORRECTION





Well test analysis report

Reservoir, well description
- Maps
- Logs
- Gross & net thickness
- Well schematic

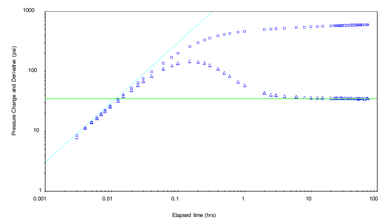
Objectives of analysis

Executive summary

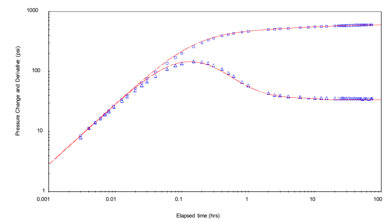
Test analysis
- Test description
- Data available
  - Pressures
  - Rates
  - Gauge depth
- Initial pressure
- Analysis process
  - Deconvolution
  - Conventional
- Analysis results

Appendices
- Nomenclature
- Origin of data (company reports)

Log-Log Diagnostic - Flow Period 2



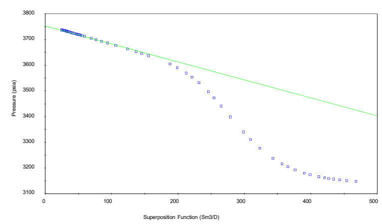
Log-Log Match - Flow Period 2



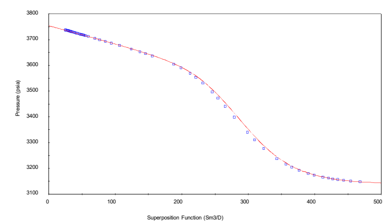
Model
Wellbore Storage and Skin (C and S)
Homogeneous
Infinite Lateral Extent

Results		
(pav)i	3755.326	psia
pwf	3139.600	psia
kh	1454.4	mD.ft
k	14.54	mD
C	0.009923	bbl/psi
S	2.07	
ri	542	ft
PI	2.622	m3/D/bar
FE	0.7717	fraction
Dp(S)	140.6	psi

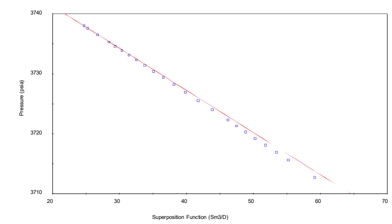
Horner Analysis - Flow Period 2



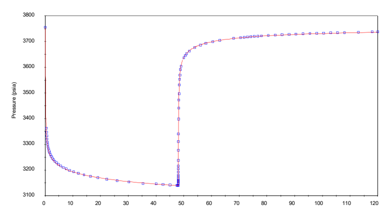
Horner Match - Flow Period 2



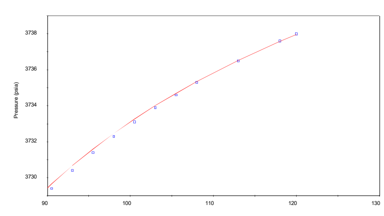
Horner Match - Flow Period 2



Simulation (Constant Skin) - Flow Period 2



Simulation (Constant Skin) - Flow Period 2



SUMMARY OF CURRENT KNOWLEDGE

RESULT FROM WELL TEST ANALYSIS:	**BEHAVIOUR (Interpretation Model)**
HOMOGENEOUS / HETEROGENEOUS:	**Applies to Behaviour, not to Description**
HETEROGENEOUS MEANS:	**Noticeable change in Mobility** kh/μ **and Storativity** $\phi\mu c_t$
ANALYSIS REQUIRES:	**Pressure AND rates**
SOLUTION NON-UNIQUE:	**By definition:** **Checking procedure (matching)** **Compare (geology, logs, other tests)** **More rate and pressure data**

WELL TEST ANALYSIS: THE FUTURE

NEW SIGNALS:

- Impulse Testing
- **Multilayered Testing**
- Harmonic Testing (Fluid acceleration / wave equation)

NEW TOOLS:

- **Downhole multiphase flowmeter**

NEW TECHNIQUES:

- **Better Identification**
- **Better Verification**
- **Deconvolution**
- **Data mining**

- **sp_D in Laplace domain**
- **Second Derivative**

NEW MODELS:

- **Multilayered**
- **Multiwell**
- **Better representation of the geology**

NEW REQUIREMENTS:

- **Reservoir characterisation**
- **Protection of the Environment**

WELL TEST ANALYSIS: THE FUTURE

TYPE OF TESTS

- **Exploration: Wireline formation tests**
- **Production: Permanent gauges**

COMPUTER <u>AIDED</u> ANALYSIS

- **No approximation necessary**
  - Superposition instead of Horner
  - Multirate type curves instead of Effective time
- **Deconvolution**
- **Expert system for Model diagnostic**
- **Direct model generation**
- **Non-linear regression**
- **Artificial Intelligence**

BATCH TO INTERACTIVE TO BATCH

- **Powerful computers with expert system**
- **Uncertainty bounds**
- **Bayesian approach: probability ranked alternative solutions**

SOFTWARE = PRODUCTIVITY AND EASE-OF-USE

<u>STILL NEED TO THINK</u>