GPC Workshop 2022

A comprehensive illustration for Petrobel's experience in evaluating productivity for non-flowing wells using Slug test technique

Presented by

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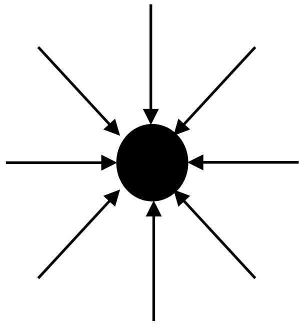
Date: 10/Oct/2022

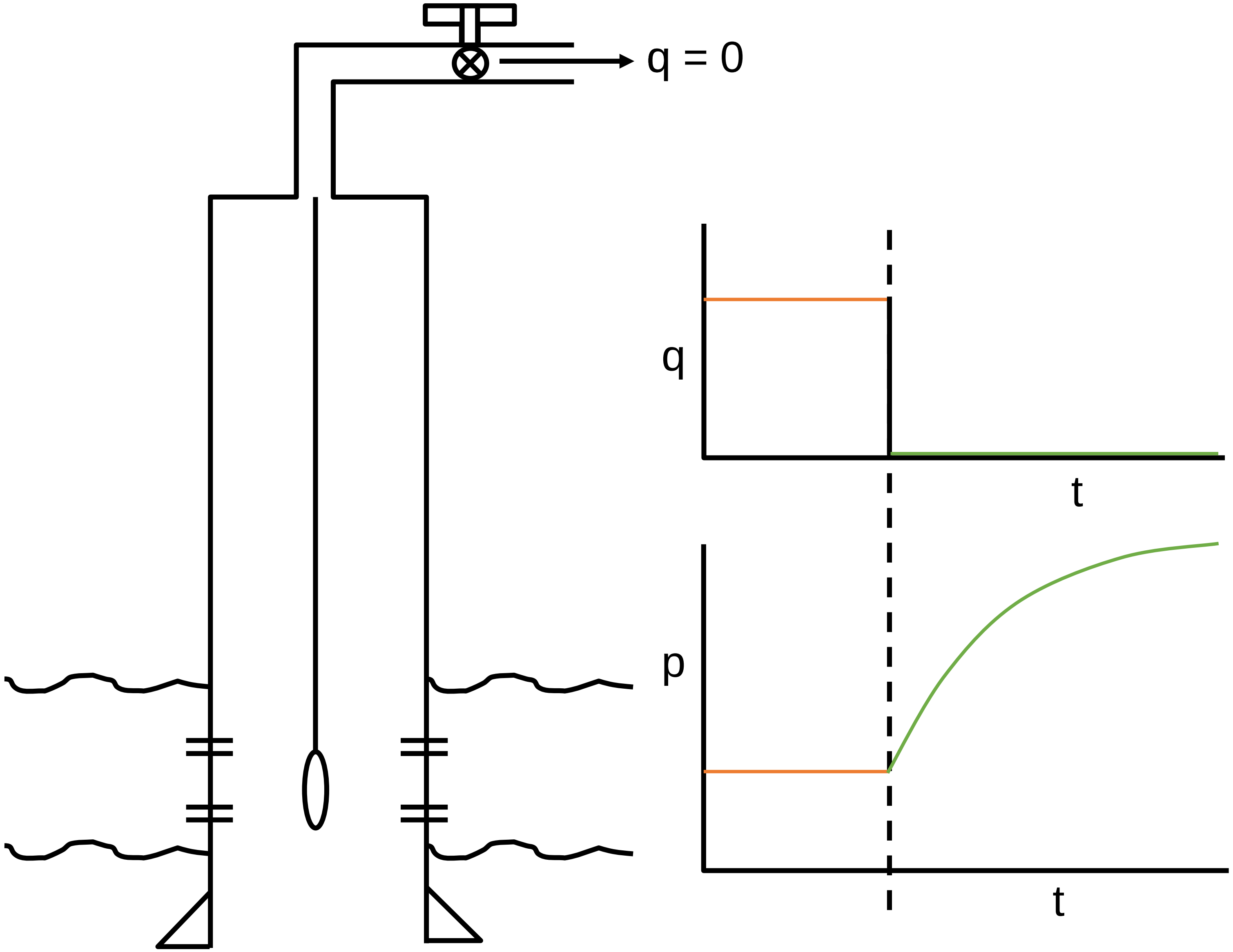
FIRST SECTION

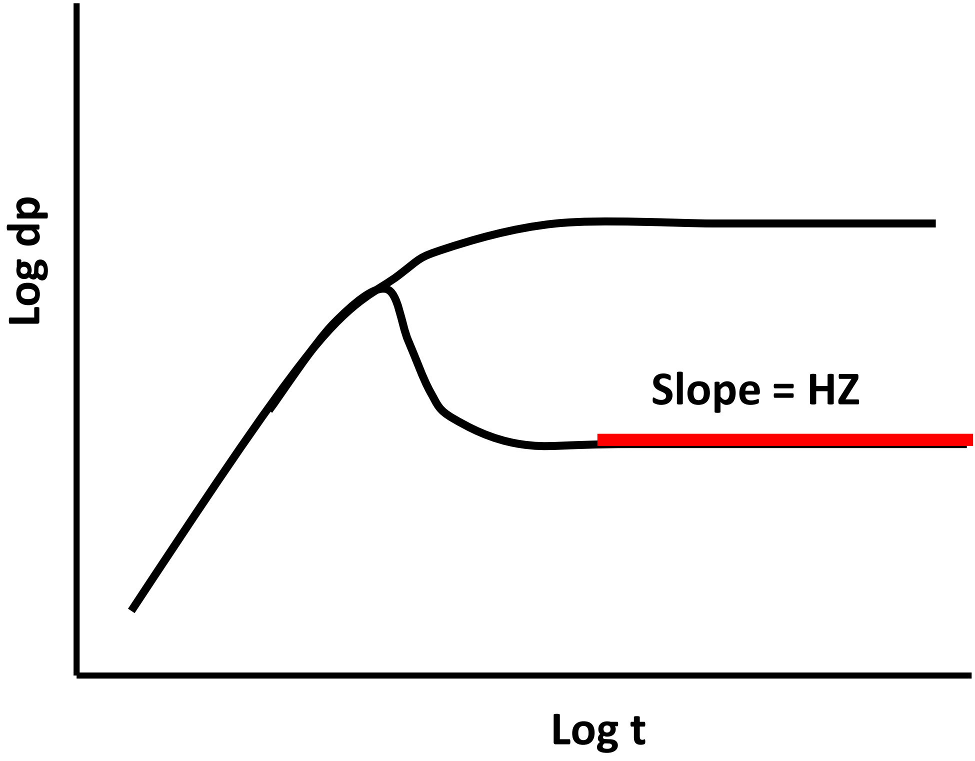
Background & Introduction

How is a well test conducted?

TRANSIENT RADIAL FLOW



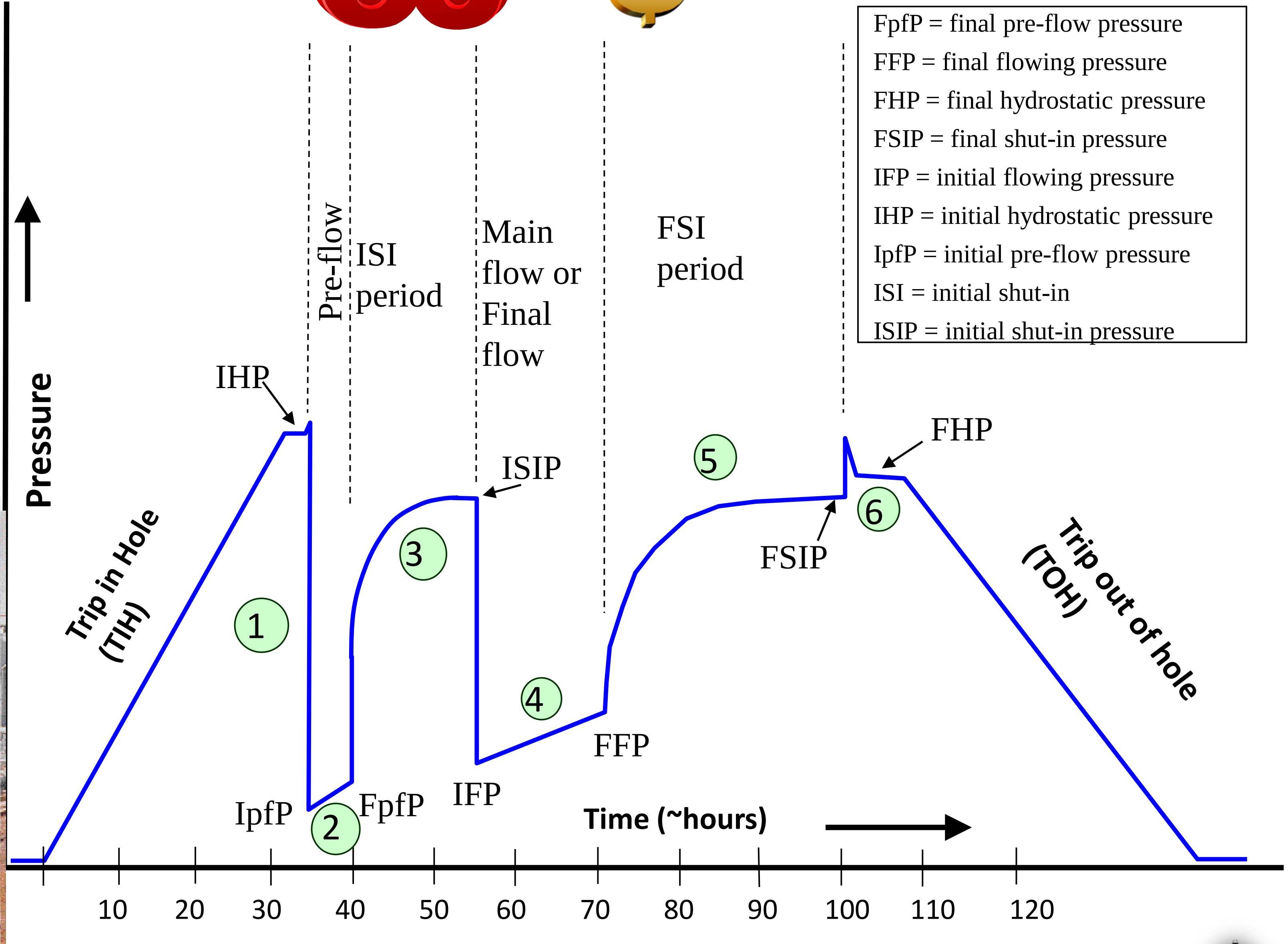




Welltest Execution

50 K$

- Typically it is a repeated series of Production and shut-in (2 cycles)
- Usually takes 5-8 days
- Comprise several components;
  - Test string (PKR & Valves).
  - Unloading method such as ; Coild tubing (N2), Swap cups, Downhole valve
  - Surface facility equipment.
  - Rate measurement meters.



Conventional DST recorder

Conventional Welltest Outlines

- Constant / stable / accurate production rate.
- Require safe handling of produced fluids.
- Challenged in non-flowing (depleted) wells.

where most of the discrepancy arises. Errors are also undoubtedly introduced by the assumption of the type of fluid entering the drillstring (all mud in the first flow period, all oil in the second flow period). Another possible source of some of the discrepancy may be that part of the production during the first flow period is a result of decompression of the wellbore fluid from hydrostatic mud pressure, about 2,300 psig, to the formation pressure of about 1,700 psig. The over-pressure in and near the wellbore can affect both the flow rate and the pressure during the first flow period. Generally, the results from the second flow period and and should be avoided if possible. Normally, one does not analyze pressure data from the first flow and shut-in periods. Results from analyzing those data tend to be less accurate than results from analyzing the second flow and shut-in periods because of longer flow duration and likely absence of mud production during the second flow period.

Analyzing Flow-Period Data

If rate variation can be estimated during the flow period, it is possible to analyze pressure data from the flow period with methods given in Section 4.2. Such multiple-rate

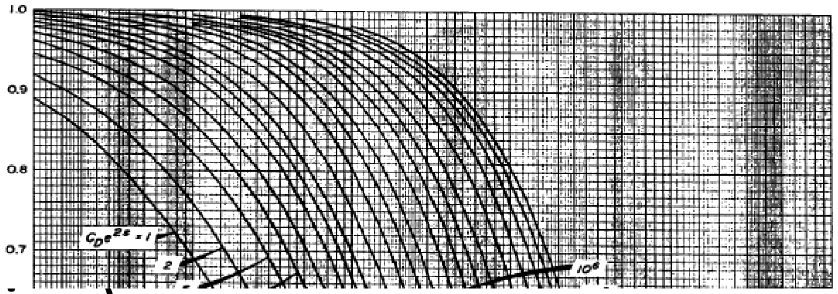
analyses can be particularly useful for wells with substantial flowing bottom-hole pressure increase that either do not flow to the surface or have insufficient surface flow time at a stable rate to provide reliable analysis results from the shut-in pressure data.

Occasionally, the pressure exerted by the produced fluid column can reach the reservoir pressure, causing production to stop during the flow period — the well kills itself. In such cases, data from the shut-in period cannot be analyzed. However, flow-period data can be analyzed by multiple-rate techniques (Section 4.2) or by type-curve matching techniques presented in Refs. 9 and 14 through 17. The type curves in Refs. 14 through 16 do not consider skin factor, so they are not recommended. Ramey, Agarwal, and Martin[9] provide type curves that include skin effect that may be used to analyze DST flow-period data *as long as flow does not reach the surface* and there is no significant change in the wellbore storage coefficient (pipe inner diamater). Figs. 8.8A through 8.8C* are the Ramey-Agarwal-Martin type curves. In those figures, the dimensionless pressure ratio is defined as

$$p_{DR} = \frac{p_D}{p_{Do}} = \frac{p_i - p_{wf}(t)}{p_i - p_o}, \quad \ldots\ldots\ldots\ldots\ldots (8.12)$$

where p_o is the pressure existing in the drillstring im-

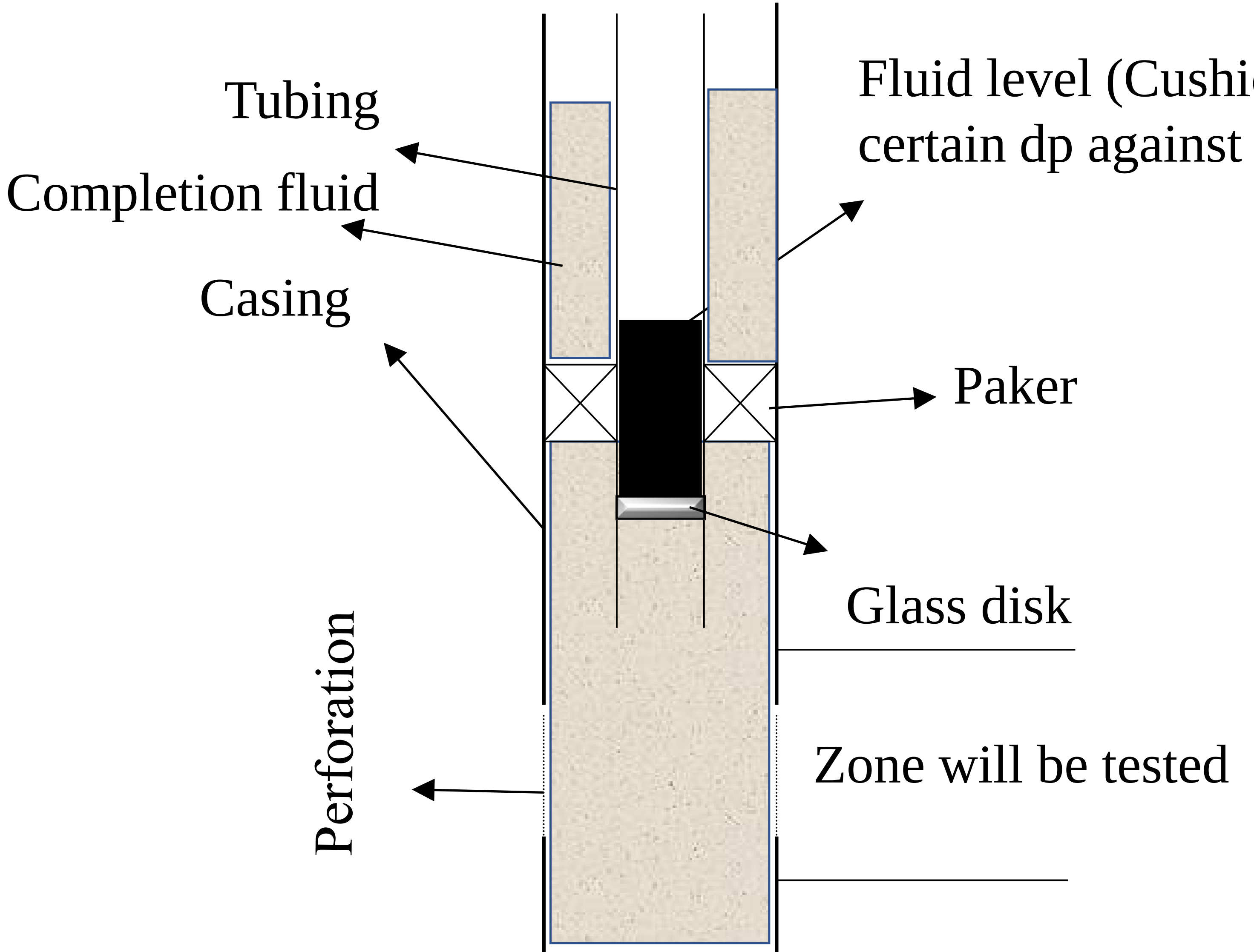
*See footnote on Page 24.



Slug Test Method

- Used mainly in non-flowing (depleted) wells.
- Can be merged with TCP (Underbalance perforation).
- Can be used in hig pressure wells if no flow is desired.

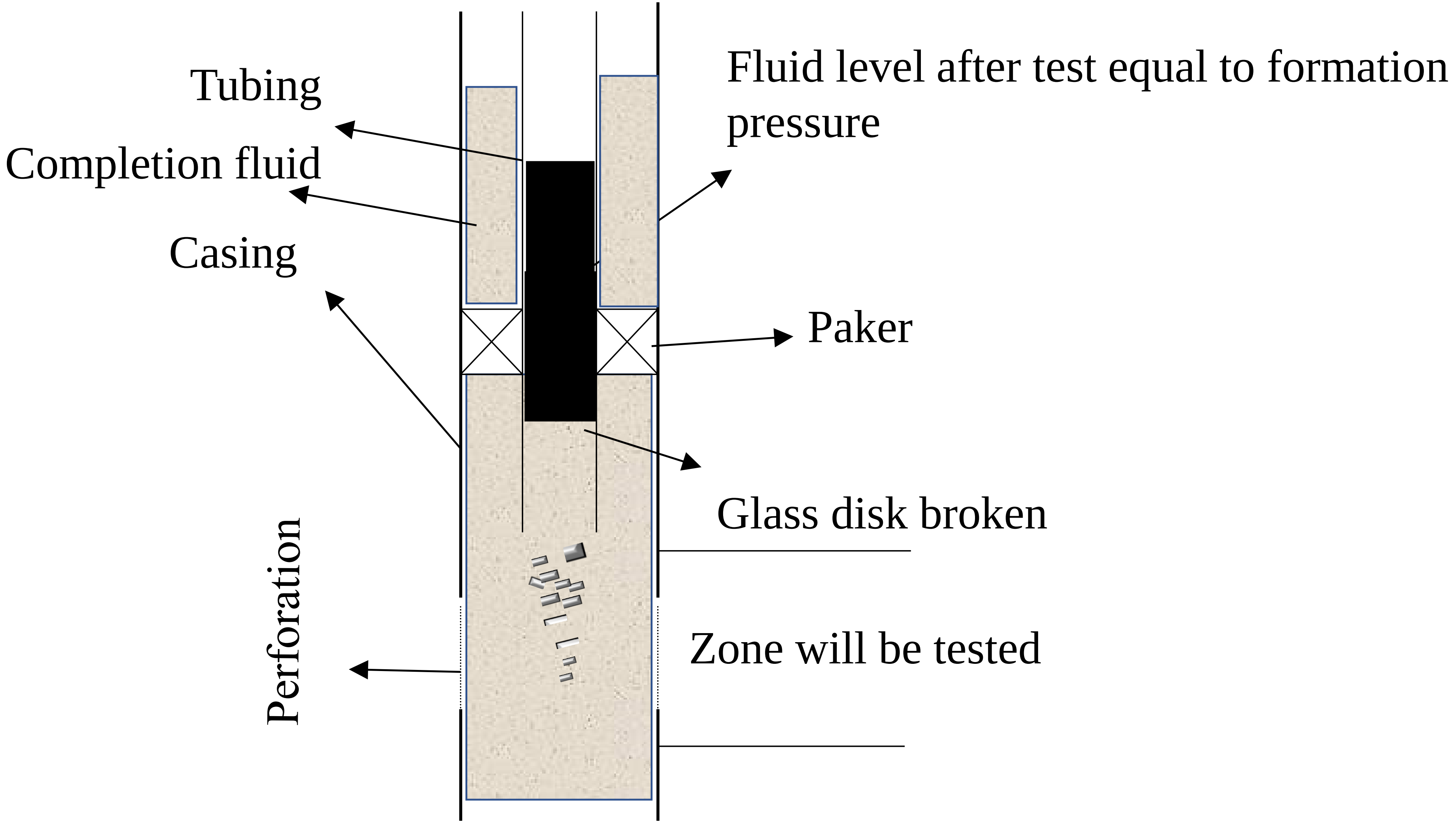
Slug Test Scheme



Before performing test

- Perform pressure drop as quick as possible (abrupt) and keep well open to allow venting the formation gas
- Single Density is prefered

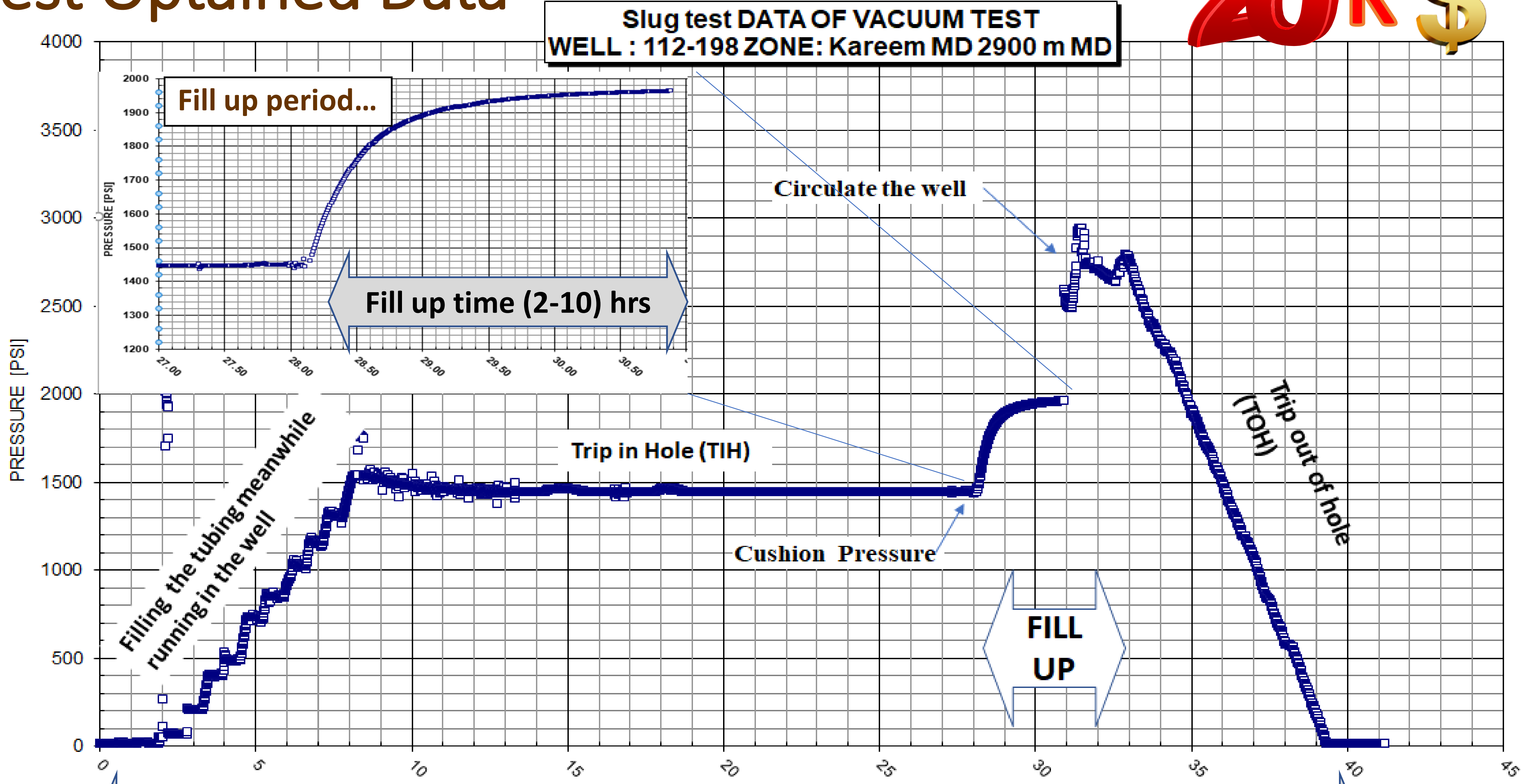
Slug Test Scheme



After performing test

Slug Test Optained Data

20K $



Overall test operation time is 2 days

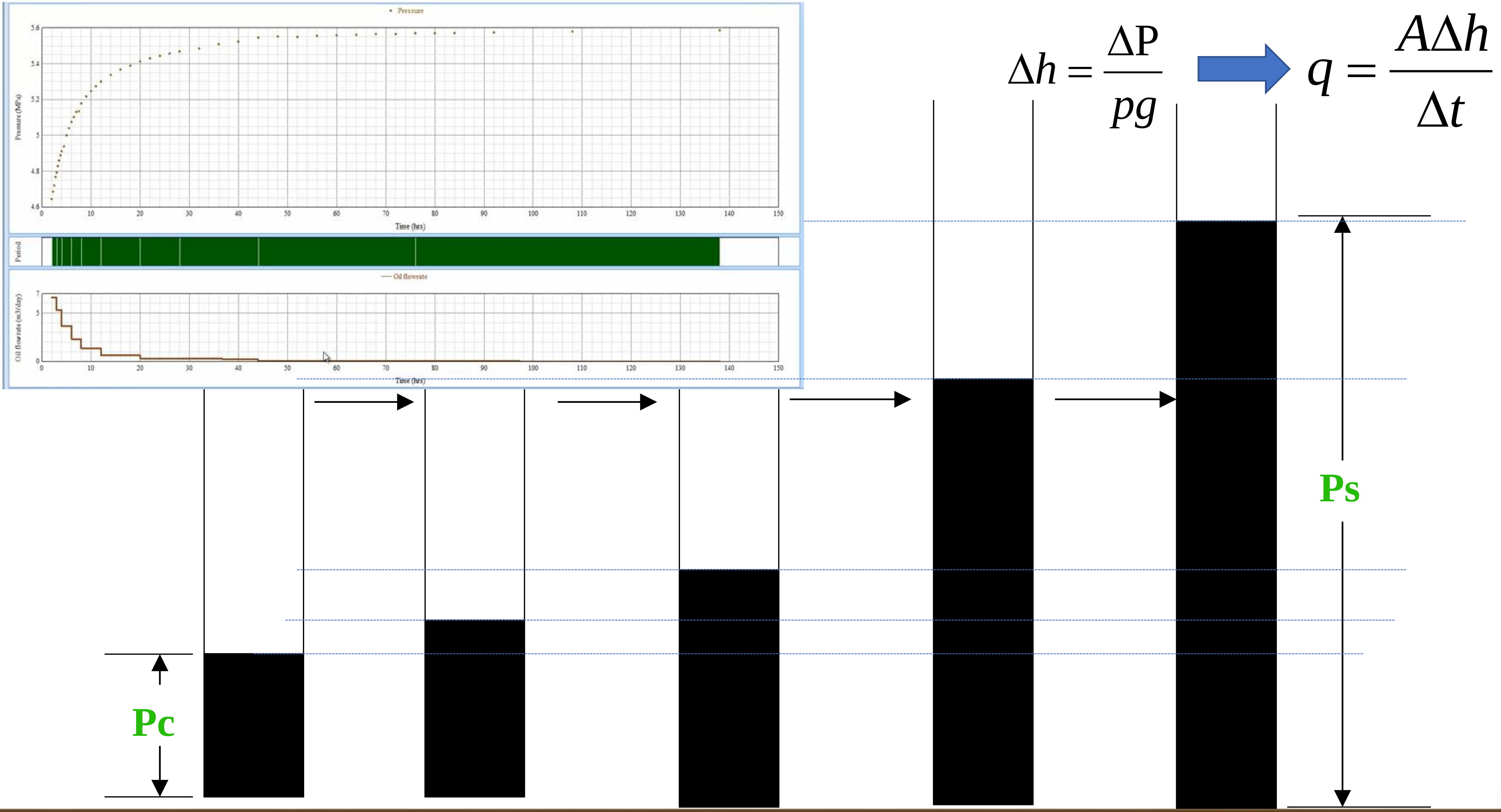
Second SECTION

Slug Test Analysis Techniques

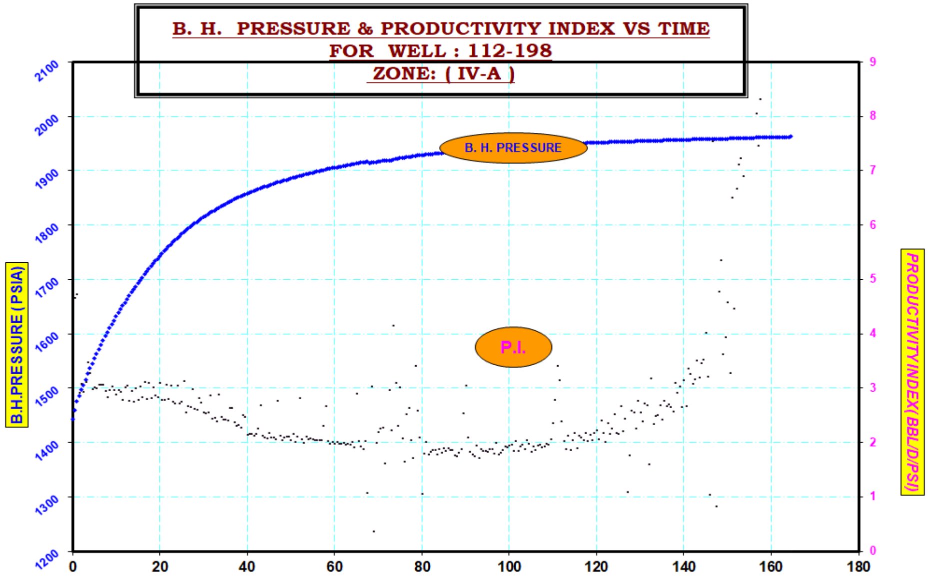
1. Rough estimation technique using spreadsheet.
2. Type curve match.
3. Commercial Software.

1. Rough estimation technique using spreadsheet.

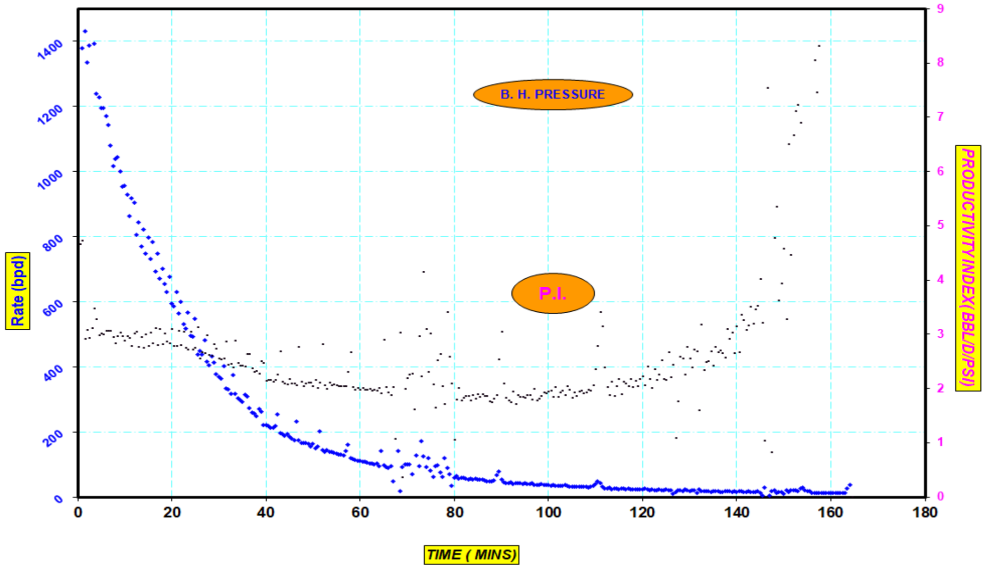
$$\Delta h = \frac{\Delta P}{pg} \Rightarrow q = \frac{A\Delta h}{\Delta t}$$



Caluclation sheet



Rate and P.I. Vs Time



FORMATION KAREEM

Date 08-May-22

FILL UP EVALUATION FOR WELL 112-198

Ps =	1962	Psi	Gauge depth =	2519.32	mMD
Po =	1443	Psi		2325	mSSL
D.P. size =	5"				
D/P. cap. 19.5 lb/ft	0.01776				
Datum	8600	ssl	T.O.Perf	2447	m ssl
Ps @ datum	**2326**		**Ps @ top perfs**	**2108**	**psi**
grad.	0.365	Psi/ft	Reservoir gradient	0.38	psi/ft

P.I. ± 1.5 BPD/PSI

TIME (T) Min.	PRESS Psi	PDR	dP Psi	dH ft	dV BBLs	RATE BBL/D	P.I. B/D/Psi	AVG. P.I. B/D/Ps
0.0	1443.33	1.000						
0.5	1459.99	0.968	16.659	45.6412	0.811	2334.49	4.647	4.647
1.0	1476.35	0.936	16.360	44.8216	0.796	2292.57	4.717	4.682
1.5	1486.20	0.917	9.845	26.9728	0.479	1379.63	2.898	4.087
2.0	1496.42	0.898	10.221	28.0017	0.497	1432.25	3.074	3.834
2.5	1505.94	0.879	9.523	26.0901	0.463	1334.48	2.924	3.652
3.0	1515.84	0.860	9.902	27.1299	0.482	1387.66	3.108	3.561
3.5	1526.63	0.839	10.789	29.5600	0.525	1511.96	3.470	3.548
4.0	1536.56	0.820	9.928	27.2010	0.483	1391.30	3.268	3.513
4.5	1545.41	0.803	8.848	24.2415	0.431	1239.92	2.974	3.453
5.0	1554.16	0.786	8.753	23.9796	0.426	1226.53	3.005	3.409
81.0	1929.53	0.063	0.470	1.2871	0.023	65.84	2.008	2.496
81.5	1929.94	0.062	0.408	1.1173	0.020	57.15	1.765	2.491
82.0	1930.35	0.062	0.417	1.1412	0.020	58.37	1.826	2.487
82.5	1930.77	0.061	0.416	1.1409	0.020	58.36	1.850	2.483
83.0	1931.18	0.060	0.410	1.1243	0.020	57.51	1.847	2.478
83.5	1931.57	0.059	0.390	1.0676	0.019	54.60	1.776	2.474
84.0	1931.98	0.058	0.405	1.1096	0.020	56.76	1.870	2.470
84.5	1932.36	0.058	0.385	1.0555	0.019	53.99	1.802	2.466
85.0	1932.76	0.057	0.398	1.0898	0.019	55.74	1.886	2.462
85.5	1933.14	0.056	0.382	1.0458	0.019	53.49	1.833	2.458
86.0	1933.53	0.055	0.386	1.0577	0.019	54.10	1.879	2.454
86.5	1933.90	0.055	0.374	1.0255	0.018	52.46	1.846	2.450
87.0	1934.27	0.054	0.371	1.0177	0.018	52.06	1.856	2.447
87.5	1934.62	0.053	0.346	0.9489	0.017	48.53	1.752	2.442
88.0	1934.96	0.053	0.339	0.9299	0.017	47.56	1.738	2.438
88.5	1935.31	0.052	0.349	0.9563	0.017	48.92	1.811	2.434
89.0	1935.66	0.051	0.354	0.9707	0.017	49.65	1.862	2.431

2. Type curve match.

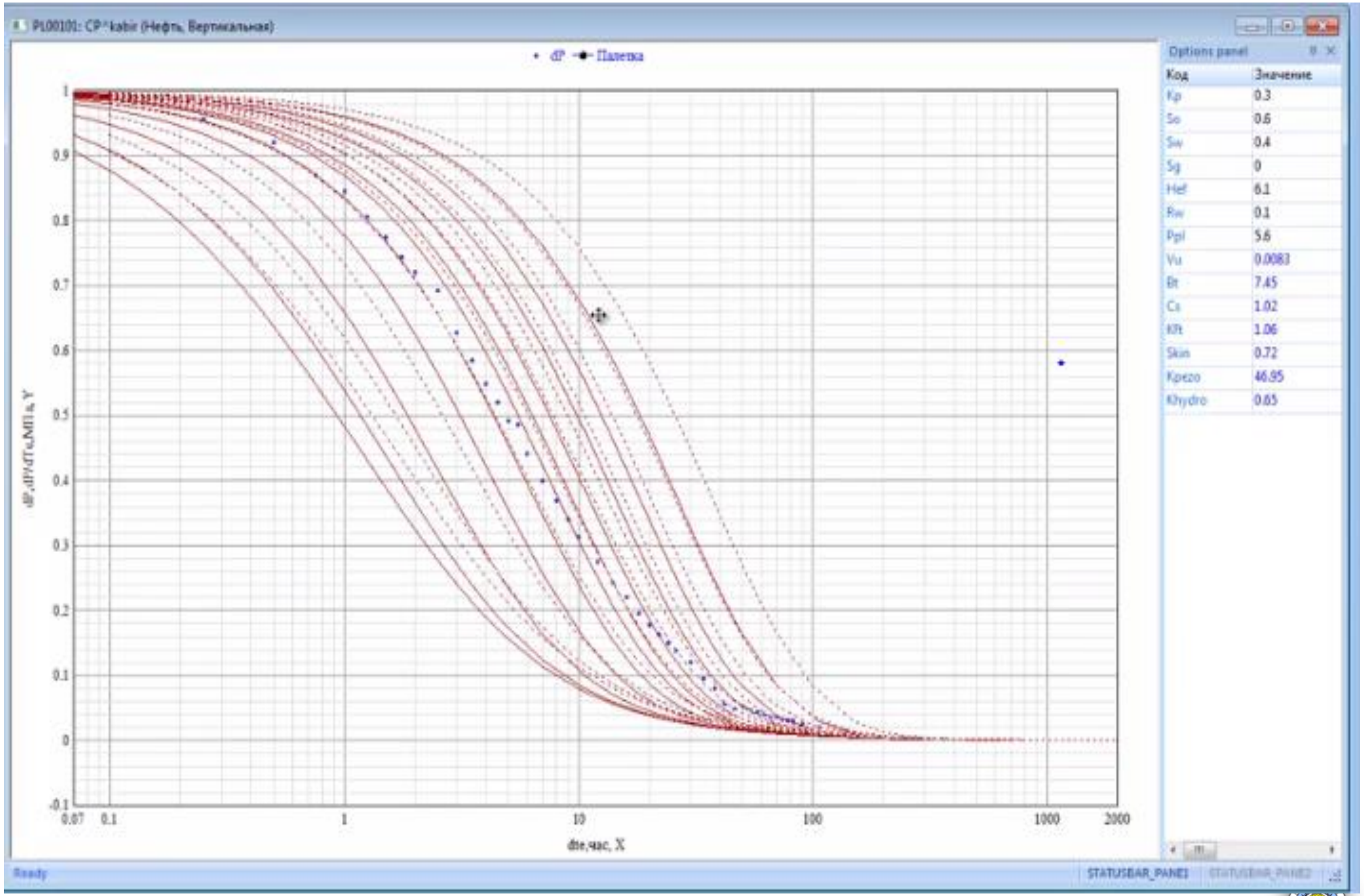
Ps =	1962	Psi
Po =	1443	Psi
D.P. size =	5"	
D/P. cap. 19.5 lb/ft	0.01776	
Datum	8600	ssl
Ps @ datum	**2326**	
grad.	0.365	Psi/ft
P.I. ± 1.5 BPD/PSI		

TIME (T) Min.	PRESS Psi	PDR
0.0	1443.33	1.000
0.5	1459.99	0.968
1.0	1476.35	0.936
1.5	1486.20	0.917
2.0	1496.42	0.898
2.5	1505.94	0.879
3.0	1515.84	0.860
3.5	1526.63	0.839
4.0	1536.56	0.820
4.5	1545.41	0.803
5.0	1554.16	0.786

$$PD = \frac{Ps - Pi}{Ps - Pc}$$

- This method is reliable provided that the density of the fluid is known and the tubing section has a uniform I.D.
- To satisfy the assumption of constant well bore storge.

N.B: After Ramey, Agarwal and Martin.



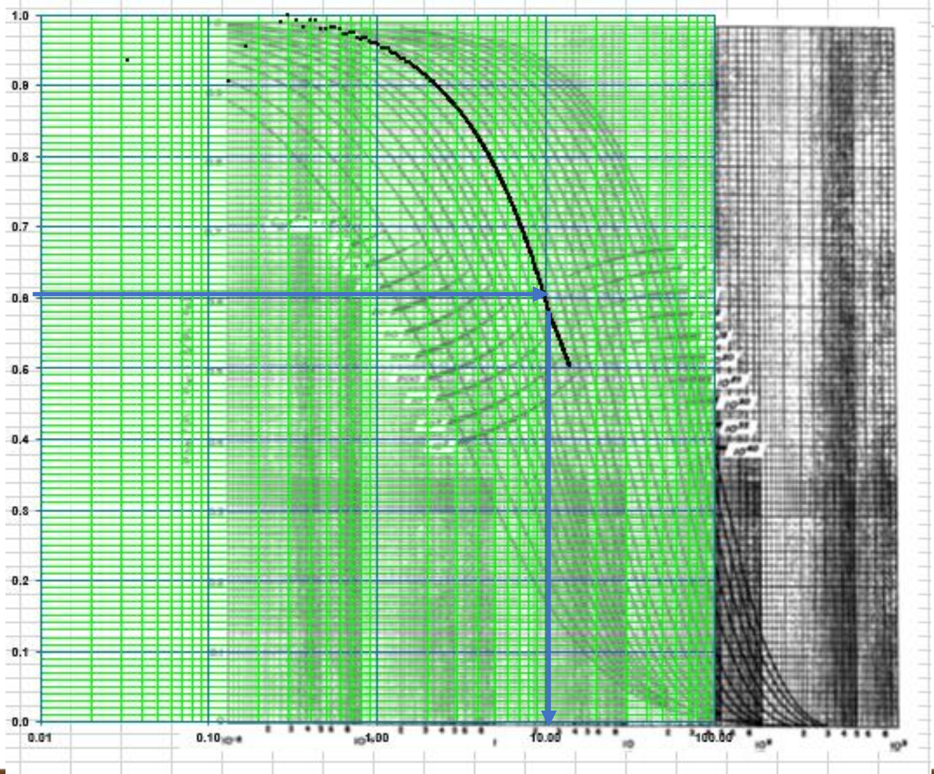
Caluclation sheet

Fill Up Interpretation by Type Curv _after Tcp_

Well Data			**Reservoir Data**			**Well /Reservoir communication**	
rw	3.5	in	Mo	0.35		Measured perf length (m)	6
	0.29	ft	Net pay (h)	3.5	mts	deviation angle	35.0
Tbg. size	4.5"	in		11.6	ft	N/G ratio	0.7
Tbg. capacity	0.01425	bbl/ft	Poro	12		non perforated interval within body (m)	1.0
Fluid grad.	0.5	Psi/ft	Ct	3.00E-06	1/psi	vertical permeability/Hz permeability ra	0.1
Wellbore storage coeff. (C)	0.0285	bbl/psi	Bo	1		derainage radius / half well spacing / boundary limit (m)	100
Estimated/expected prod rate	1100	bpd	Ln re/rw	7.03		derainage Area (acrge)	7.8

Type Curve Match Data

curve1			**curve1**		
Cde^2s	1.00E+05		Cde^2s	2.00E+02	
tm	10	min	tm	1	min
tD/CD	0.1667	hrs	tD/CD	0.0167	hrs
			tD/CD)curve	0.0900	hrs



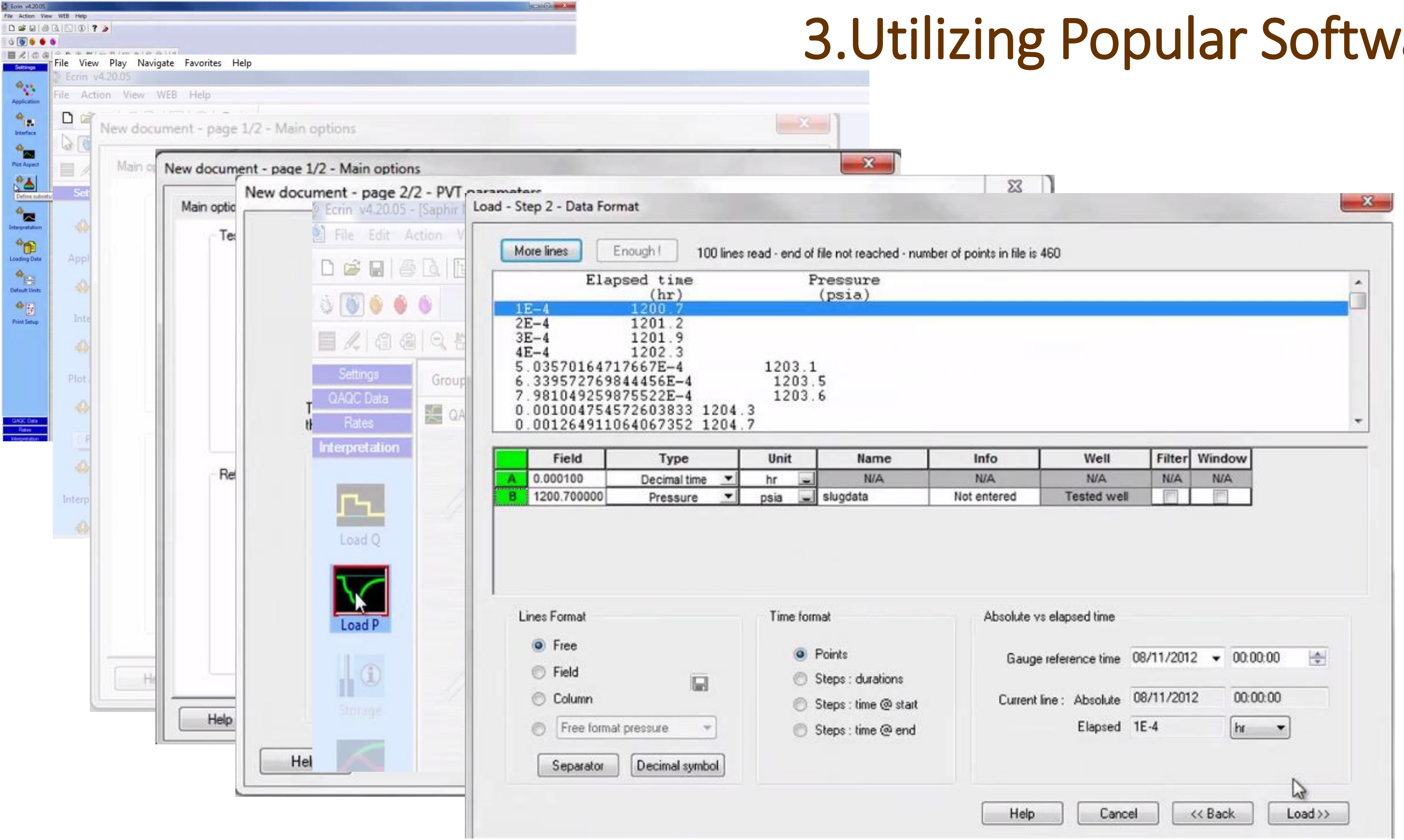
$$K = 3.389 \frac{\mu}{h} \times \frac{C}{t_M} \left(\frac{t_D}{C_D} \right)_M$$

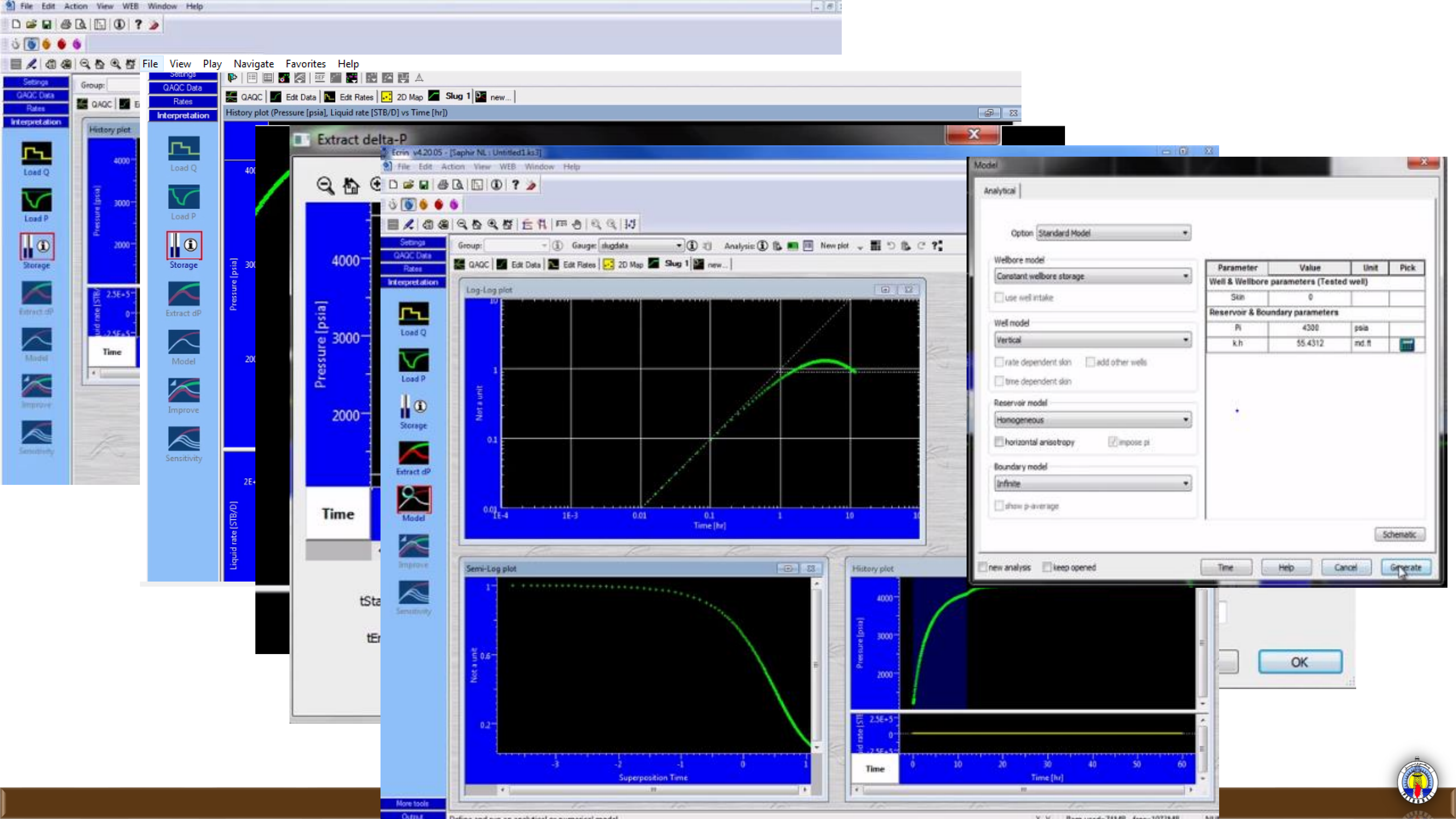
$$S = \frac{1}{2} \ln \left(\frac{\theta \, C_t h r_w^2 \left(C_D e^{2S} \right)_M}{0.89359 \quad C} \right)$$

Calculations

Perm. (k)	=[(3389*Mo*C*(tD/CD)m)/(h*tm)]	
	15.7	md
Skin (S)	=1/2ln[(phi*Ct*rw2*h*(Cde^2s))/(0.89359*C)]	
	-0.64	
P.I.	=(0.00708*K*h)/(Bo*Mo*(ln(re/rw))	
	0.53	
P.I. Skin	=(0.00708*K*h)/(Bo*Mo*(ln(re/rw+s-.75))	
	0.65	
Flow efficiency/	125	

3.Utilizing Popular Software





File Edit Action View WEB Window Help
File View Play Navigate Favorites Help
Settings
QAQC Data
Rates
Interpretation
Load Q
Load P
Storage
Extract dP
Model
Improve
Sensitivity
History plot (Pressure [psia], Liquid rate [STB/D] vs Time [hr])
QAQC
Edit Data
Edit Rates
2D Map
Slug 1
new...
Extract delta-P
Pressure [psia]
Time
Ecrin v4.20.05 - [Saphir NL : Untitled1.ks3]
Group:
Gauge:
slugdata
Analysis:
New plot
Log-Log plot
Not a unit
Time [hr]
Semi-Log plot
Superposition Time
History plot
Liquid rate [STB/D]
More tools
Model
Analytical
Option
Standard Model
Wellbore model
Constant wellbore storage
use well intake
Well model
Vertical
rate dependent skin
add other wells
time dependent skin
Reservoir model
Homogeneous
horizontal anisotropy
impose pi
Boundary model
Infinite
show p-average
Parameter
Value
Unit
Pick
Well & Wellbore parameters (Tested well)
Skin
0
Reservoir & Boundary parameters
Pi
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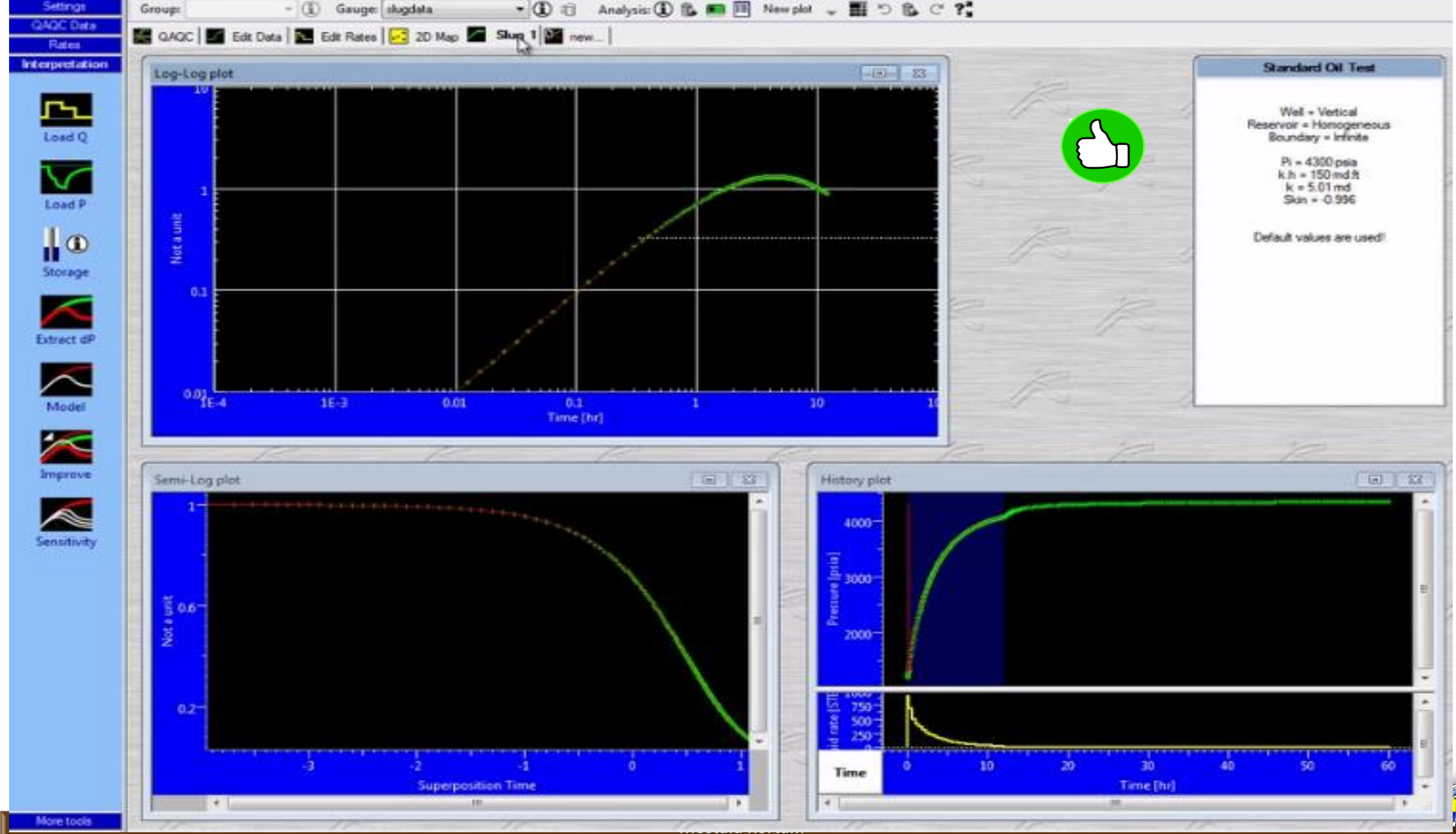
new analysis
keep opened
Time
Help
Cancel
Generate
OK


Settings
QAQC Data
Rates
Interpretation
Load Q
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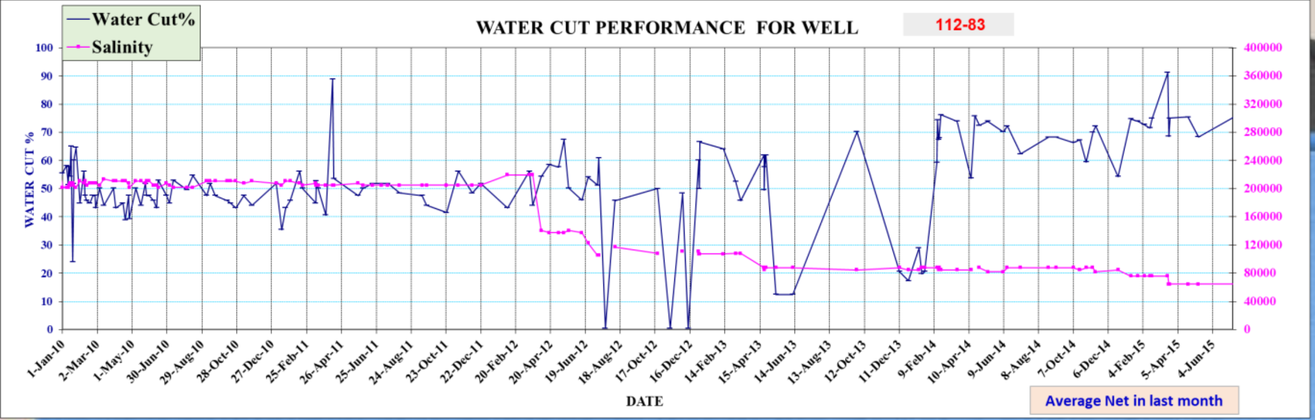
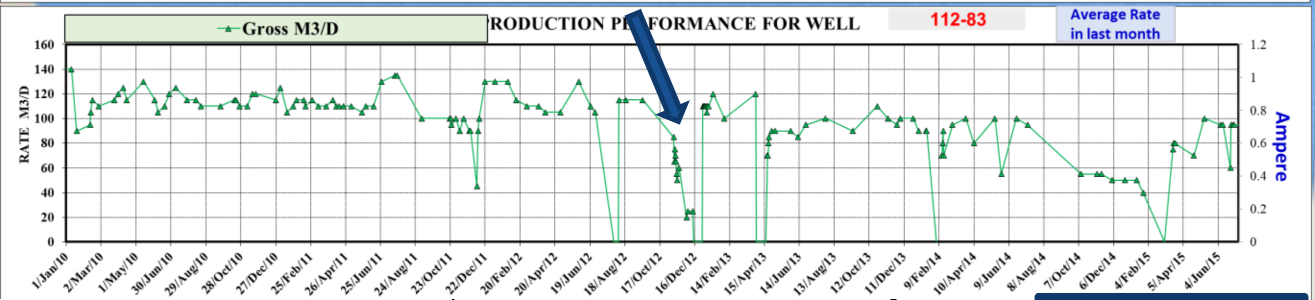
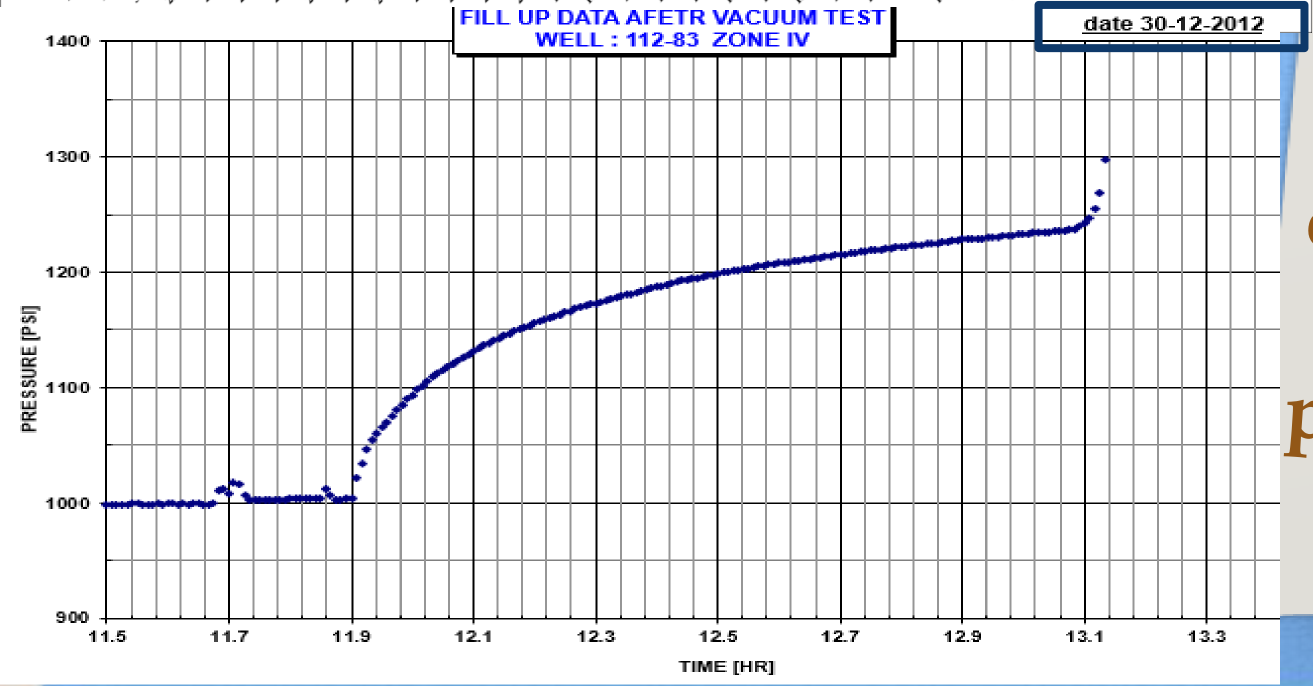
Storage
Extract dP
Model
Improve
Sensitivity
More tools
Group:
Gauge: slugdata
Analysis:
New plot
QAQC
Edit Data
Edit Rates
2D Map
Slug 1
new...
Log-Log plot
Not a unit
Time [hr]
Semi-Log plot
Superposition Time
History plot
Pressure [psia]
Time
Time [hr]
Standard Oil Test
Well = Vertical
Reservoir = Homogeneous
Boundary = Infinite
Pi = 4300 psia
k.h = 150 md.ft
k = 5.01 md
Skin = -0.996
Default values are used!

Third SECTION

Petrobel's Operational Excellence

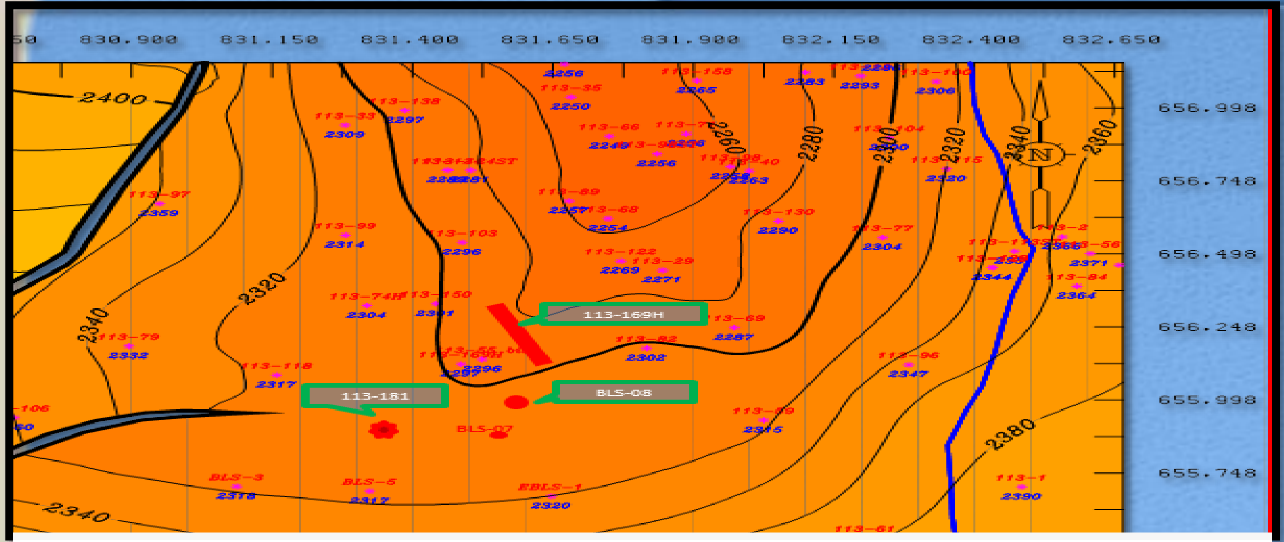


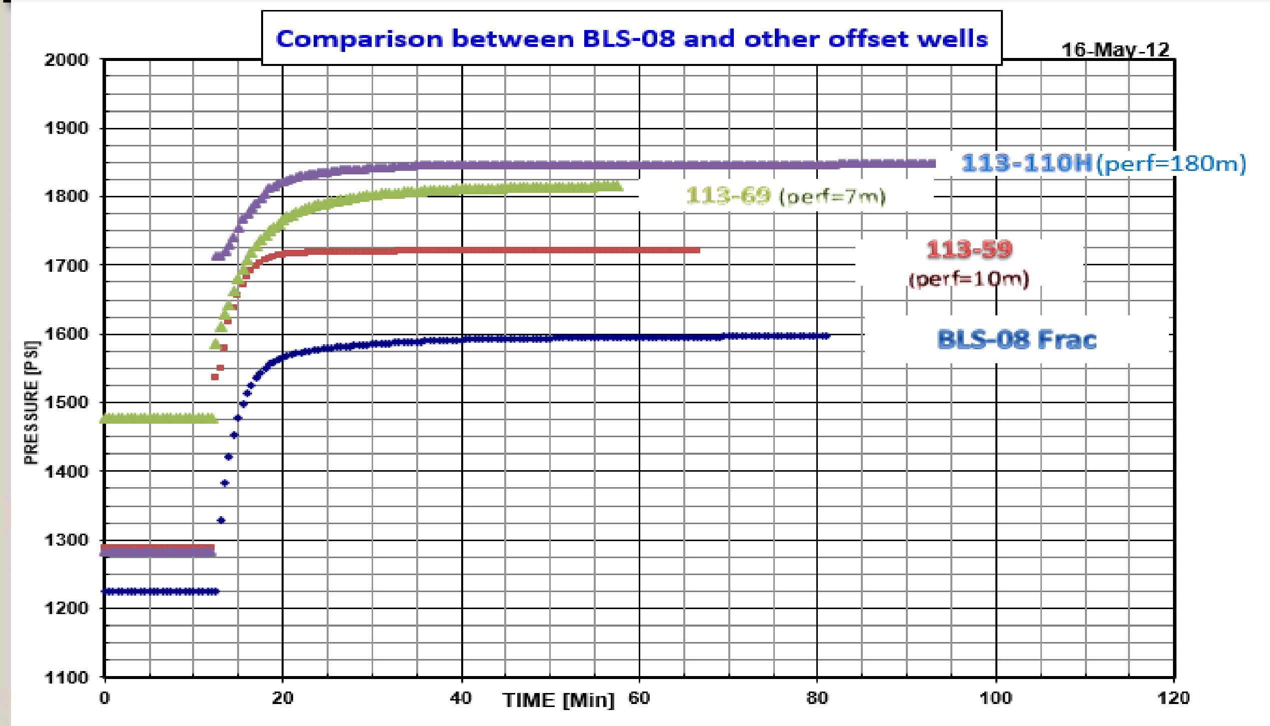




Improve Well Performances

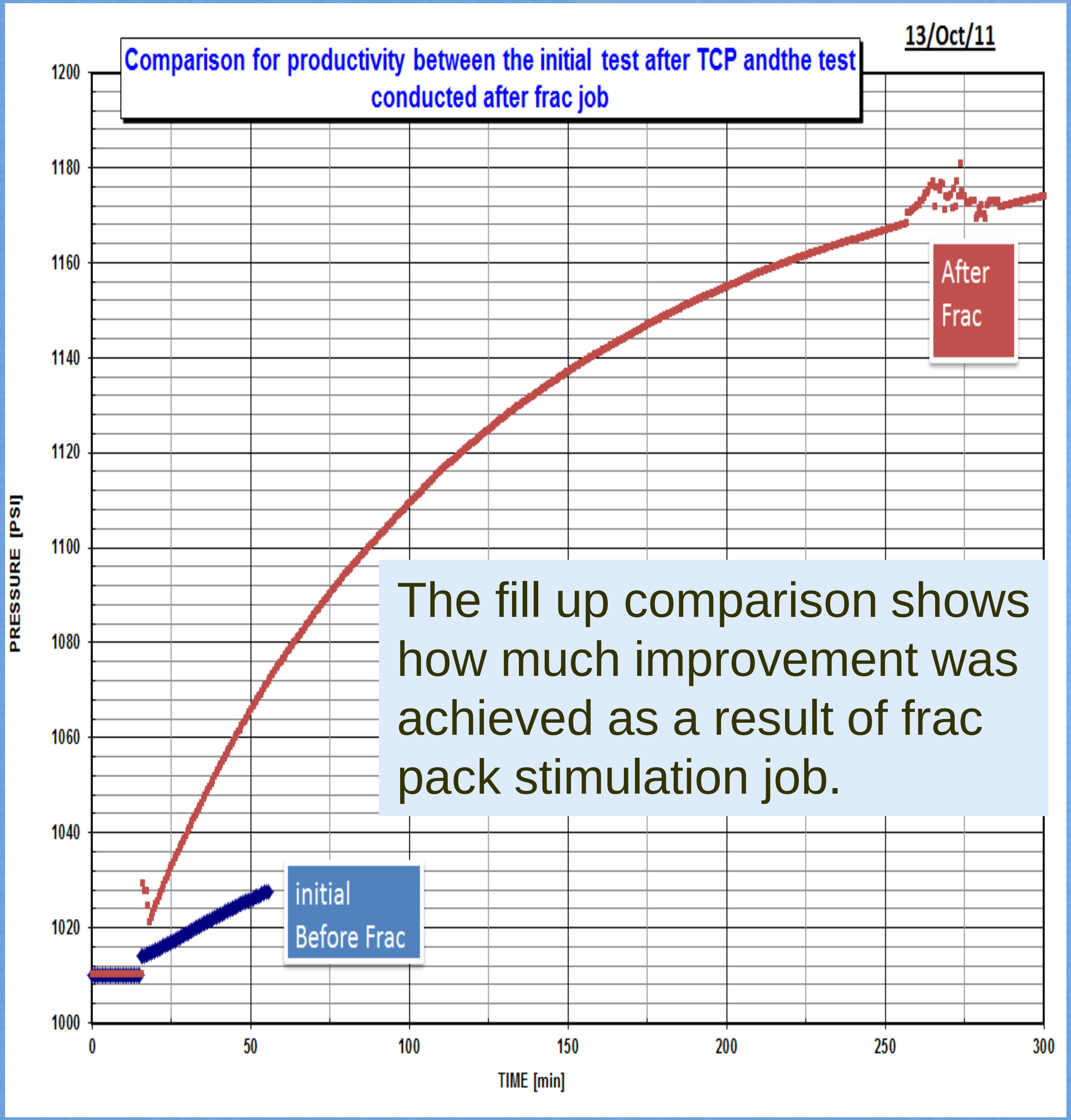
Clean Perforation tunnel by unplugging the deposit through creating sudden differential pressure would mobilize the clogging material





Formation Heterogeneity Identification

Compare wells producing from same pool and detect underperforming wells & define formation chractristics



Accurate Treatment Judge

Without waiting cleanup post frac treatment and avoiding putting wells on Production test for longer time

Finally !!

Conclusion

Constructing Workflow Strategy

Step 1

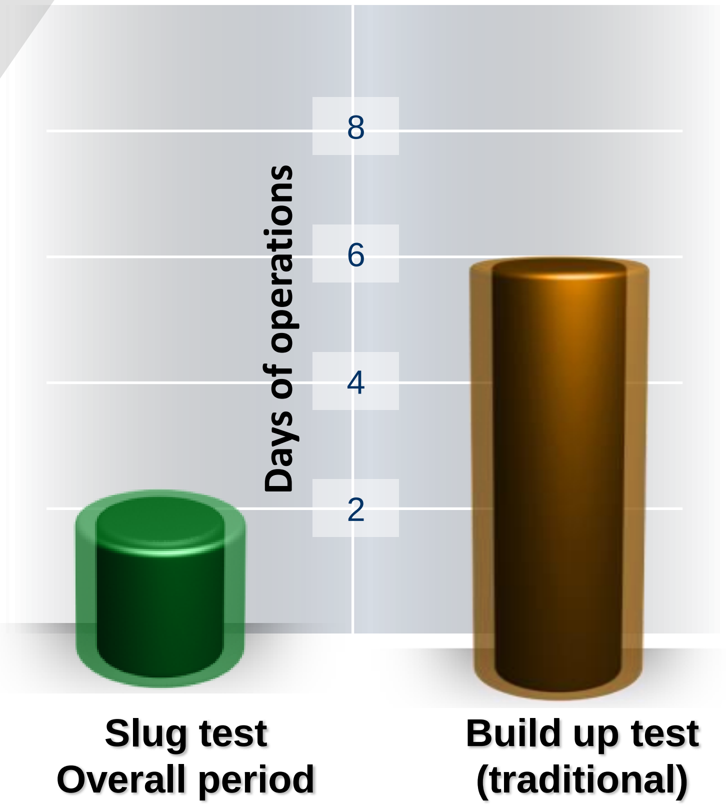
- Conduct the Slug test

Step 2

- Compare with other Slug tests *(offset wells, previous tests)*

Step 3

- Calibrate with Surveillance methods *(DH sensor, Ecometer pulse, Nodal model match)*



Impact of the application…

- Several advantages can be obtained with utilizing such test.

Operational time reduction

Quick treatment Judge

Effective cost optimization

Safe and simple (no need to manage produced volumes)

Precise comparison with less variables “Certainty”

Well Heterogeneity Identification

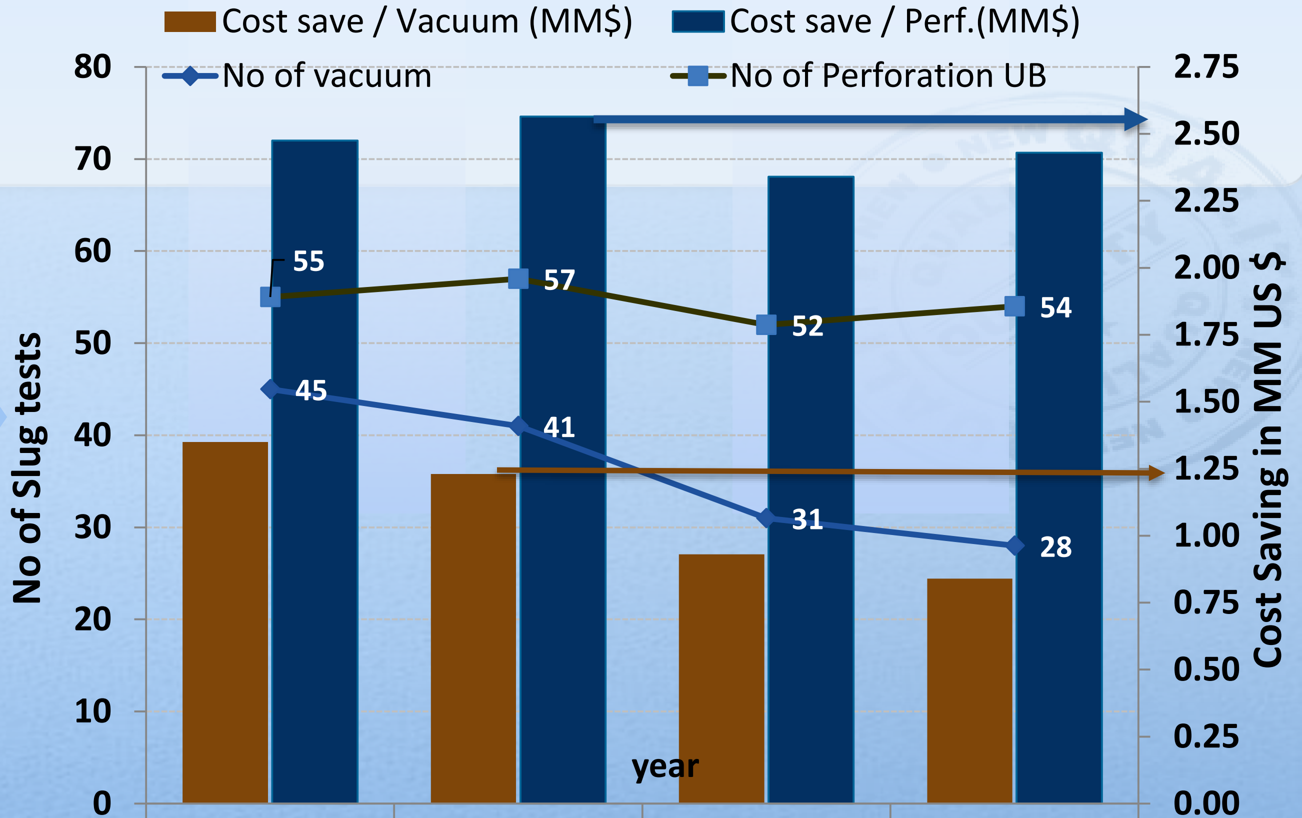
Outcome Here

Operation Scheme is 2 Drilling rigs and 8 WO rigs

350 Active well.

Results

No of Slug tests vs Cost saving over Traditional Well Tests



	2018	2019	2020	2021
Cost save / Vacuum (MM$)	1.35	1.23	0.93	0.84
Cost save / Perf.(MM$)	2.48	2.57	2.34	2.43
No of vacuum	45	41	31	28
No of Perforation UB	55	57	52	54
	3.83	3.8	3.27	3.27

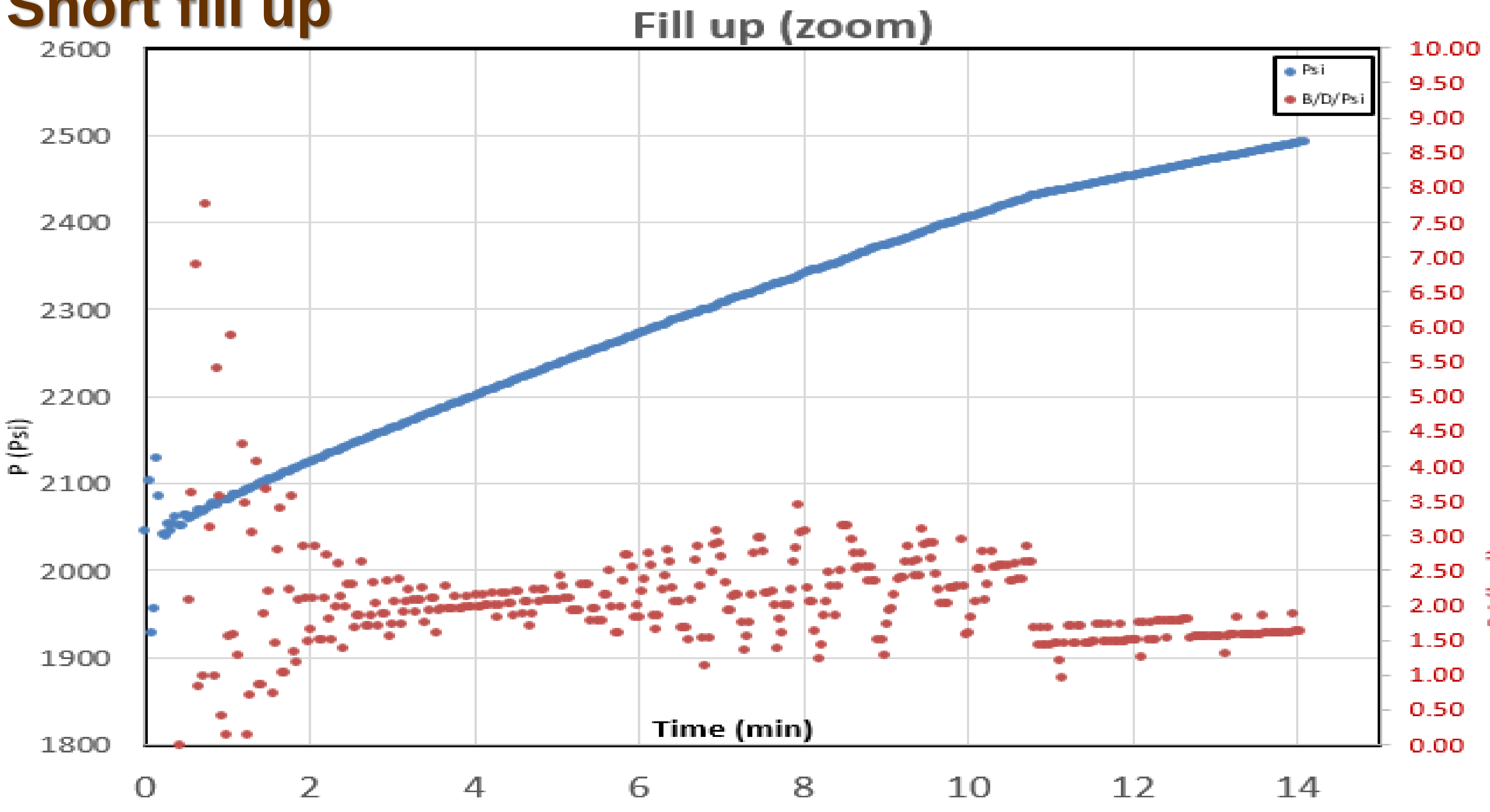
THANK YOU

Questions?

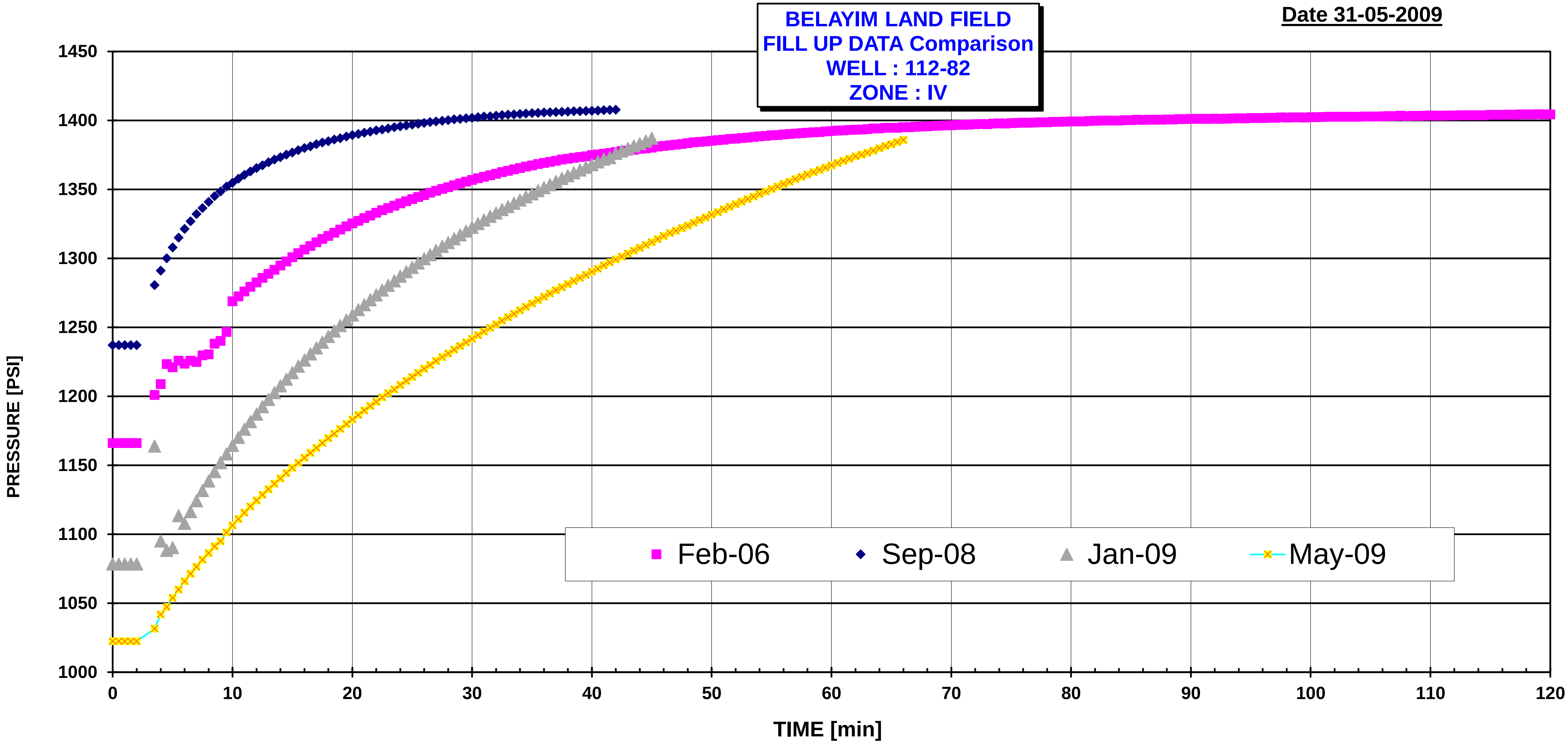
Petrobel

Back up slids

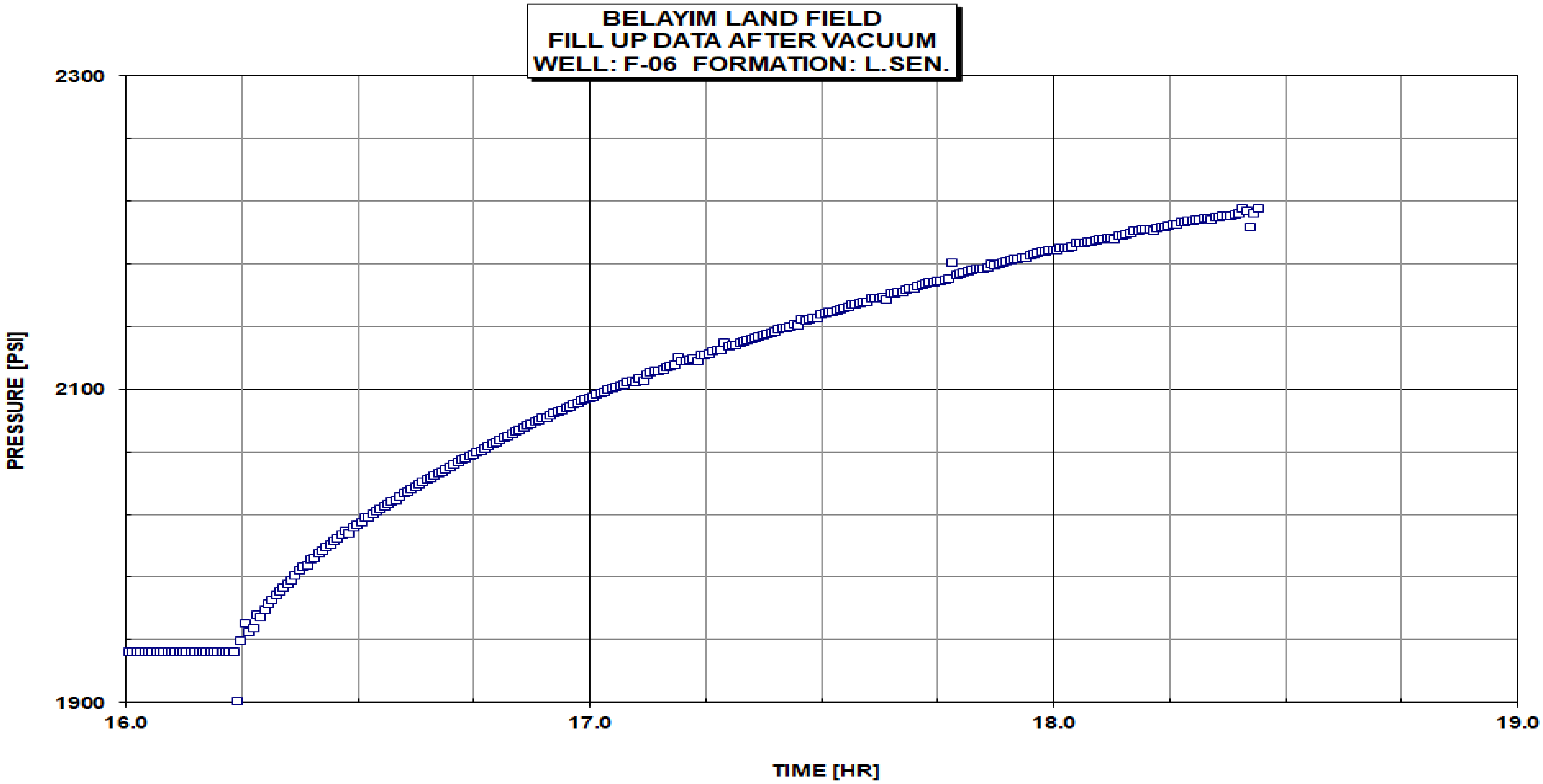
Short fill up

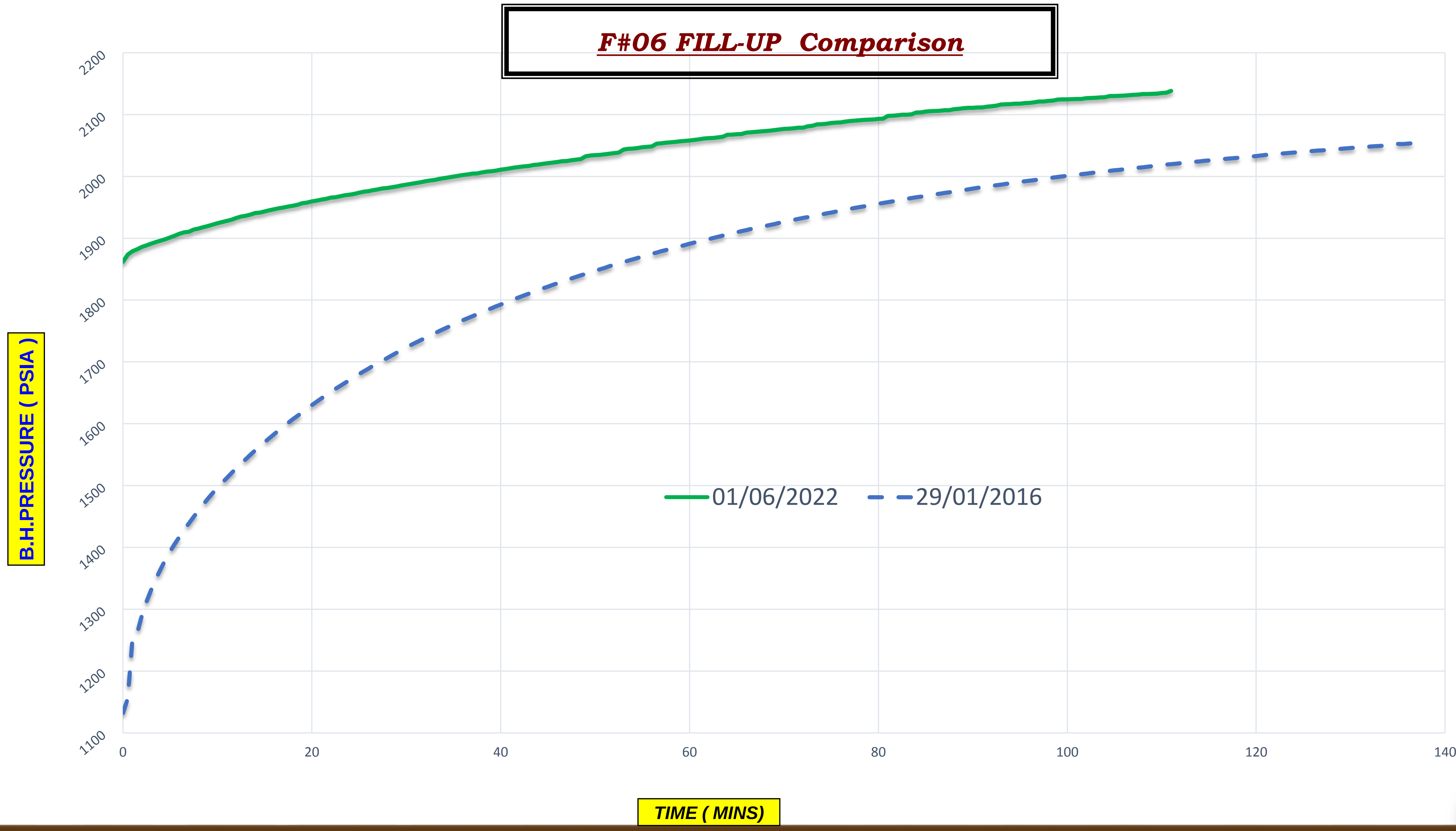


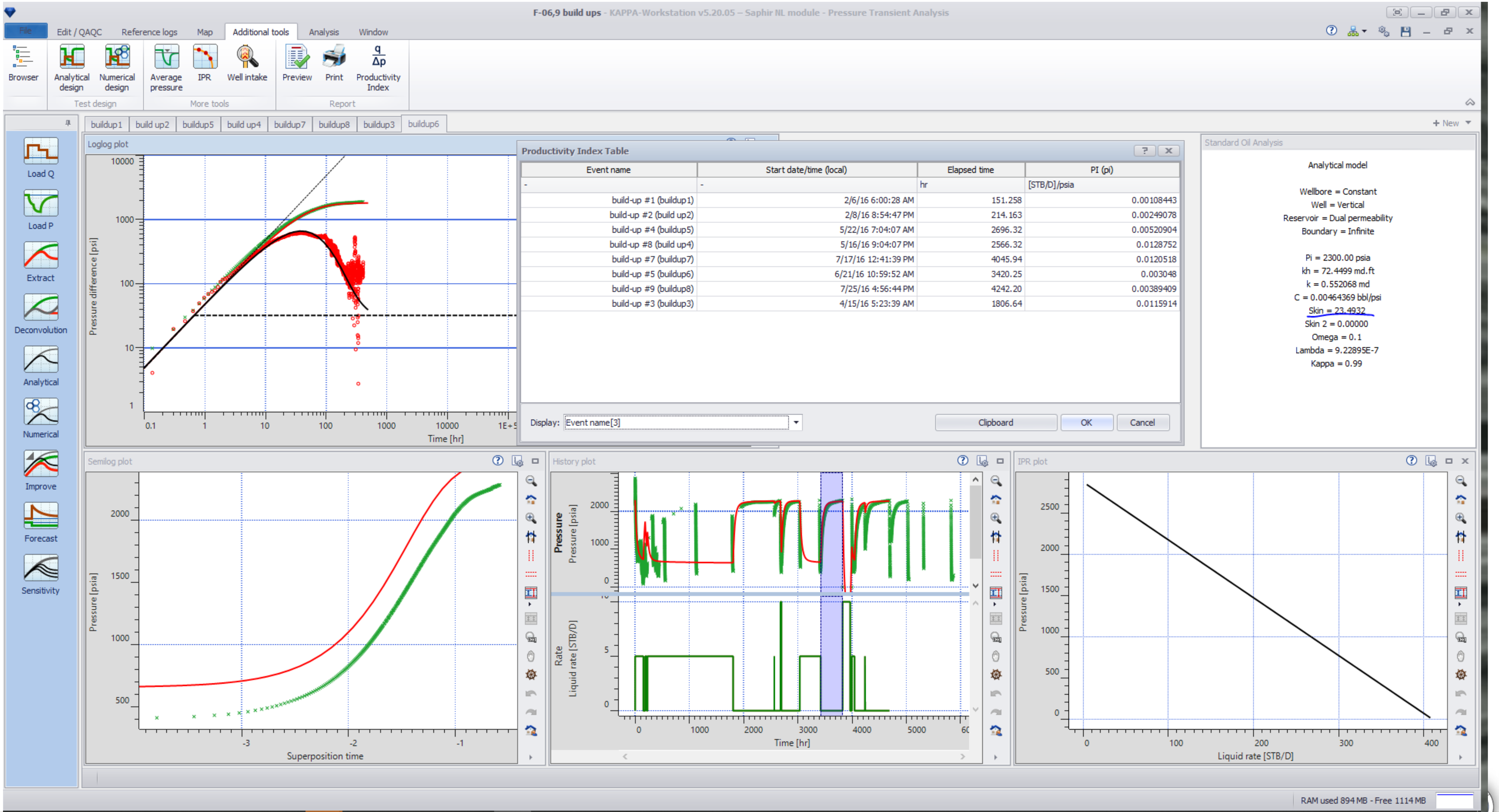
Time lapse productivity decline



Caliberation with Buildup

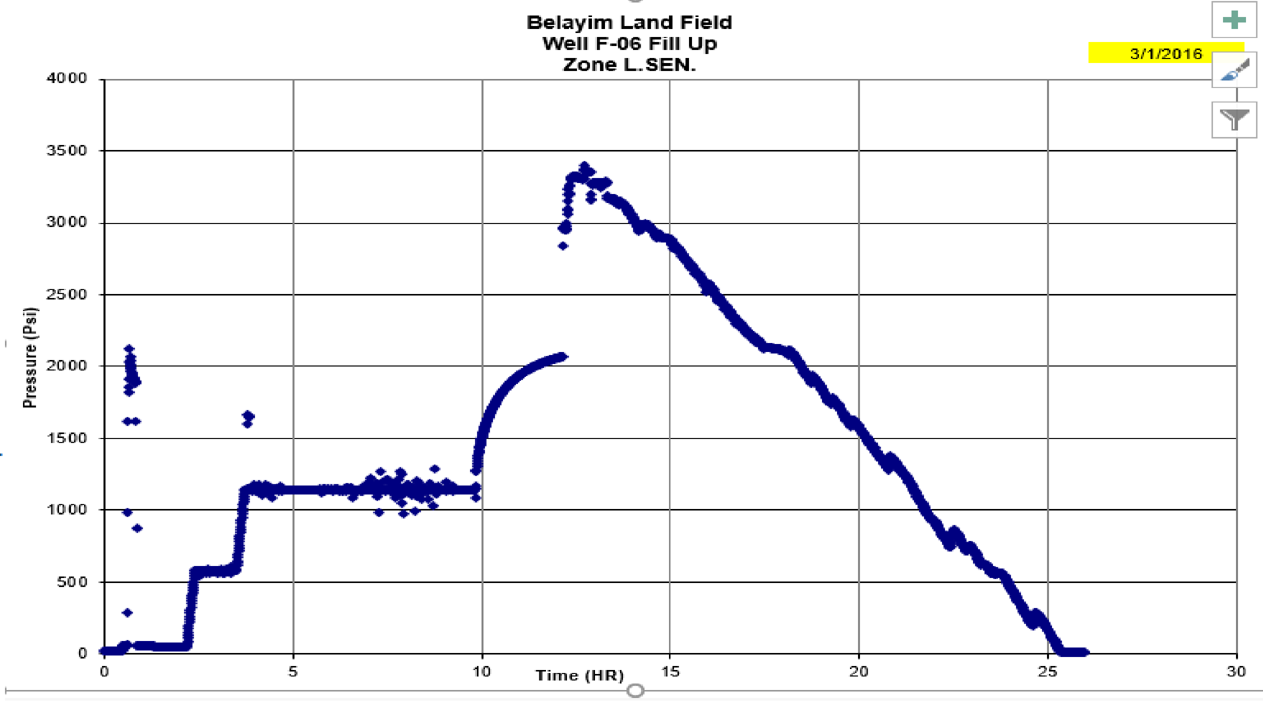



F#06 FILL-UP Comparison
B.H.PRESSURE (PSIA)
2200
2100
2000
1900
1800
1700
1600
1500
1400
1300
1200
1100
0
20
40
60
80
100
120
140
01/06/2022
29/01/2016
TIME (MINS)



Event name	Start date/time (local)	Elapsed time	PI (pi)
-	-	hr	[STB/D]/psia
build-up #1 (buildup1)	2/6/16 6:00:28 AM	151.258	0.00108443
build-up #2 (build up2)	2/8/16 8:54:47 PM	214.163	0.00249078
build-up #4 (buildup5)	5/22/16 7:04:07 AM	2696.32	0.00520904
build-up #8 (build up4)	5/16/16 9:04:07 PM	2566.32	0.0128752
build-up #7 (buildup7)	7/17/16 12:41:39 PM	4045.94	0.0120518
build-up #5 (buildup6)	6/21/16 10:59:52 AM	3420.25	0.003048
build-up #9 (buildup8)	7/25/16 4:56:44 PM	4242.20	0.00389409
build-up #3 (buildup3)	4/15/16 5:23:39 AM	1806.64	0.0115914

Slug test in flowing wells (deep)



FILL UP EVALUATION

Ps =	2090	Psi	Gauge depth =	1727.65	mMD
Po =	**1147**	Psi		1718	mSSL
Tbg. size =	3.5	in			
Tbg. cabacity =	0.00742	bbls/ft	DP =	943.2	
datum	9000.0	ft ssl	Top Perfs	**3142**	m ssl
Ps @ datum	**4182.9**	**Psi**	Ps @ top perfs	**4706**	psi
cushion fluid grad.	0.560	Psi/ft	Pressure gradient	0.46	Psi/ft

Flowing

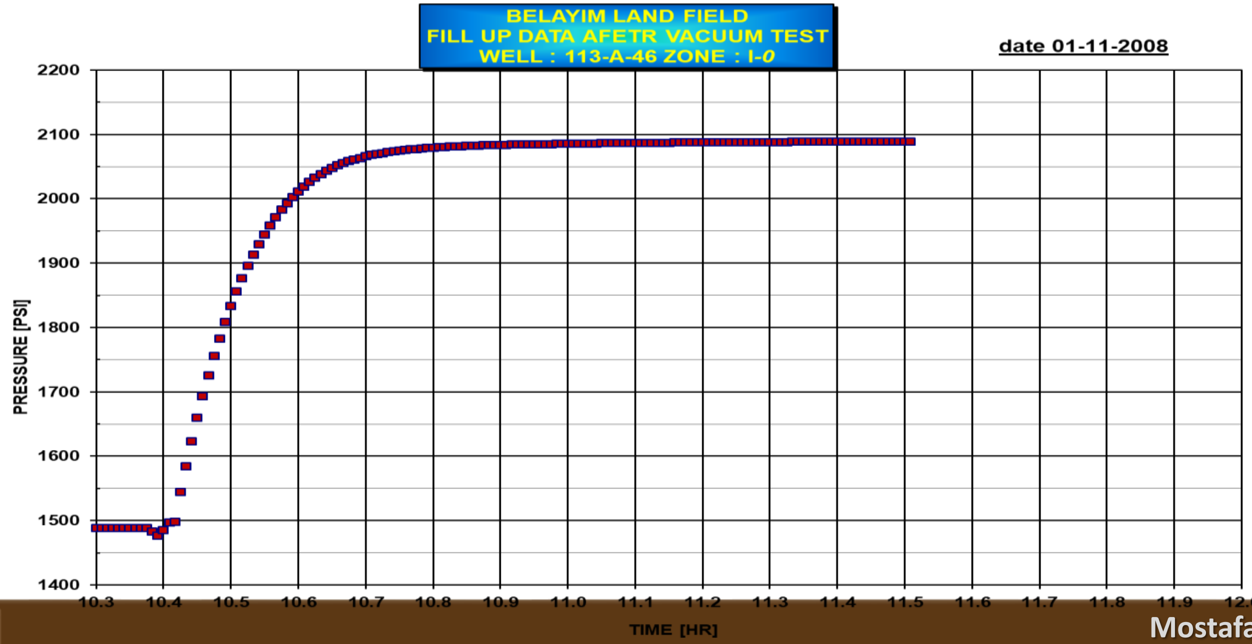
TIME (T)	PRESS	PDR	dP	dH	dV	RATE
Min.	**Psi**		**Psi**	**ft**	**BBL**	**BBL/D**
0.0	1146.8	1.00000				
0.5	1082.89	1.06776	-63.9	-114.1250	-0.847	-2438.81
1	1170.32	0.97506	87.4	156.1250	1.158	3336.33
1.5	1267.27	0.87228	97.0	173.1250	1.285	3699.61
2	1275.93	0.86309	8.7	15.4643	0.115	330.47

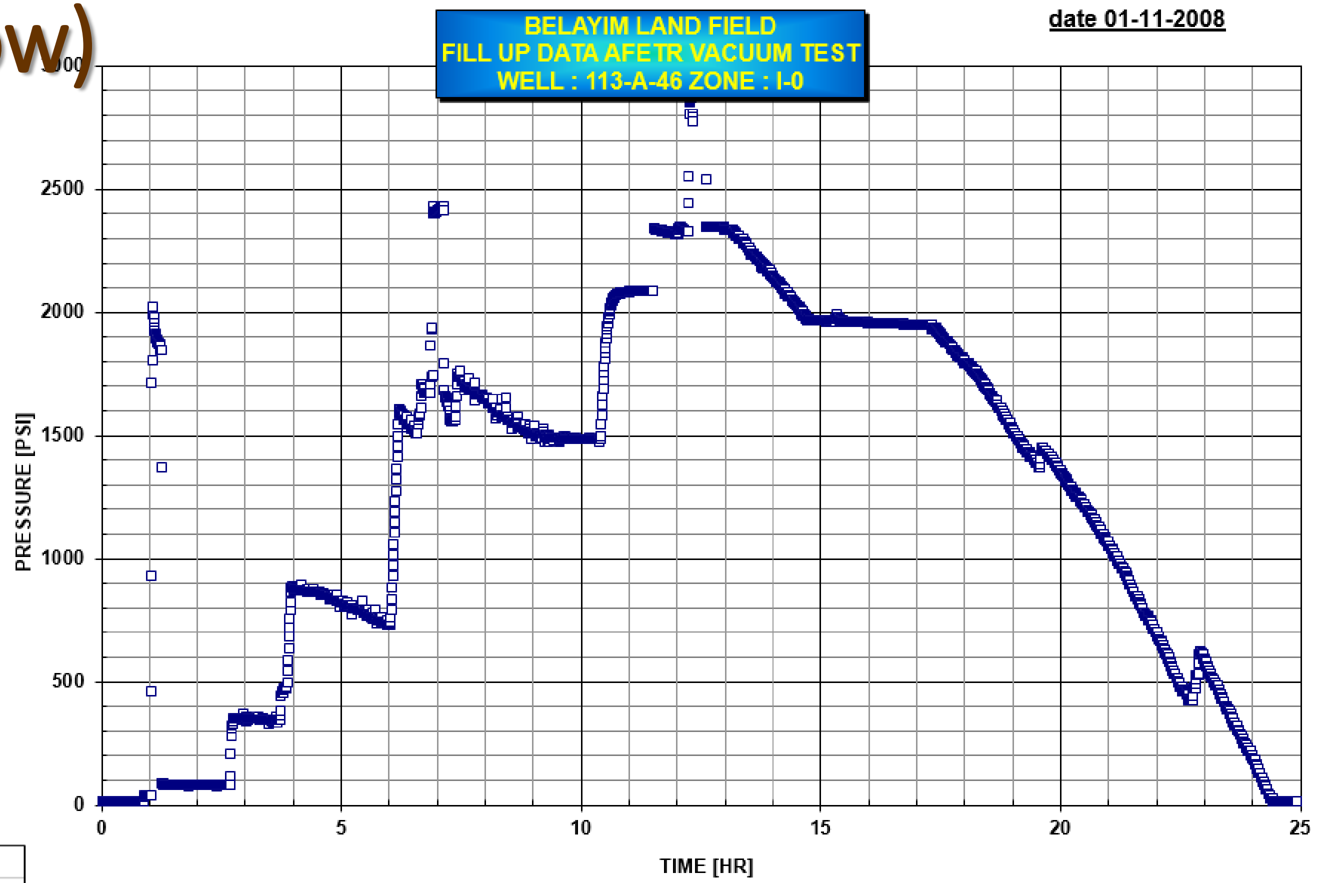
Slug test in flowing wells (shallow)

FILL UP EVALUATION

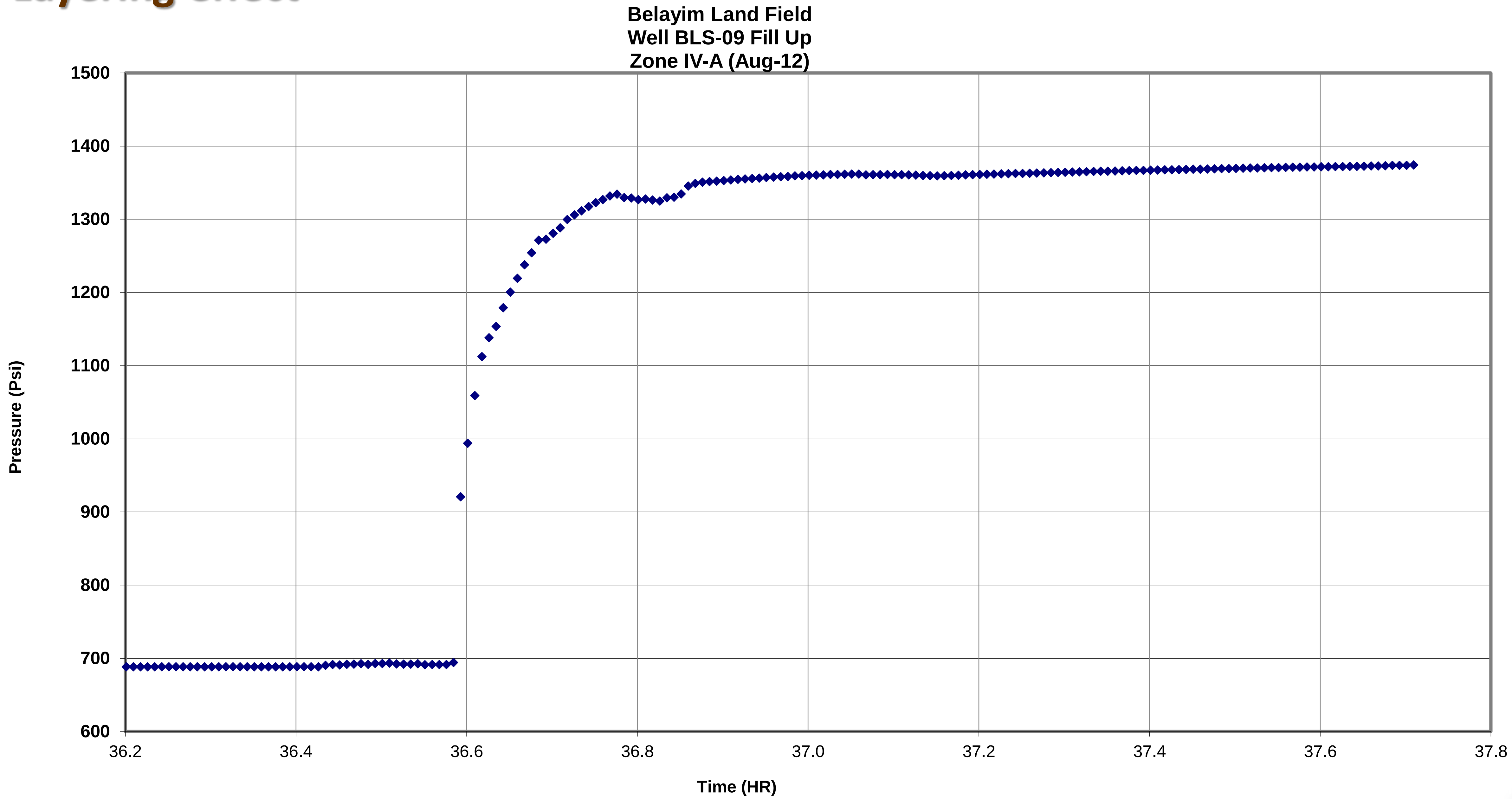
Ps =	2089.00	Psi	Gauge depth =	1724	mMD
Po =	1498.24	Psi		1381	mSSL
Tbg. size =	3 1/2	in			
Tbg. cabacity =	0.00735	bbls/ft			
datum	4870	ft ssl	Top Perfs	1483.5	m ssl
Ps @ datum	**2260.8**	Psi	Ps @ top perfs	2261	psi
grad.	0.5066	Psi/ft		0.465	Psi/ft

TIME (T)	PRESS	PDR	dP	dH	dV	RATE
Min.	Psi		Psi	ft	BBLs	BBL/D
0	1498.24	1.00000				
0.5	1544.70	0.92136	46.45849	91.7065	0.674	1940.45
1	1583.93	0.85495	39.22791	77.4337	0.569	1638.45
1.5	1623.52	0.78794	39.59021	78.1489	0.574	1653.58
2	1659.46	0.72710	35.94165	70.9468	0.521	1501.19
2.5	1693.50	0.66948	34.03967	67.1924	0.494	1421.75
3	1725.63	0.61509	32.12964	63.4221	0.466	1341.97
3.5	1755.27	0.56492	29.63818	58.5041	0.430	1237.91

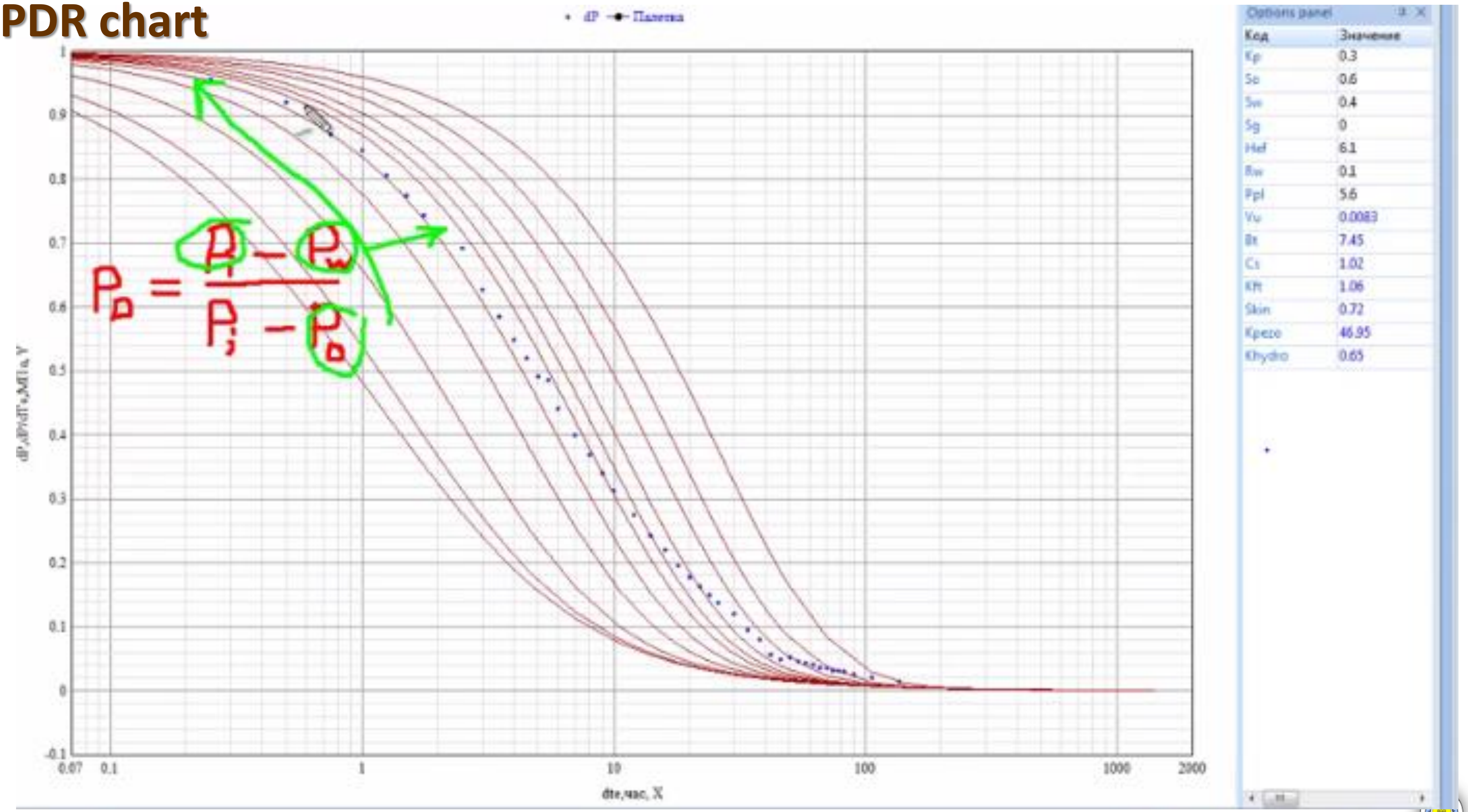


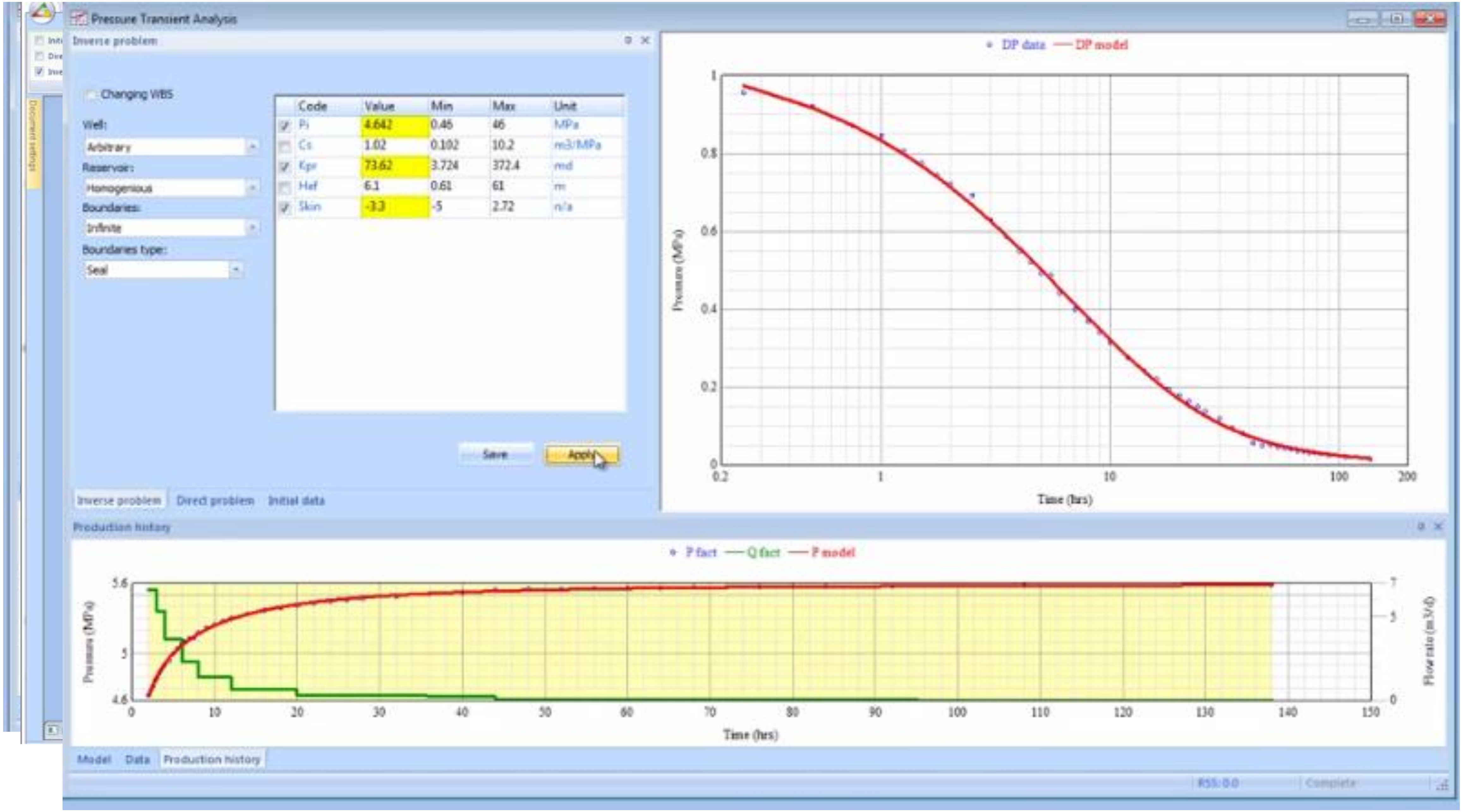


Layering effect



PDR chart


dP
Палетка
dte,час, X
Options panel
Код Значение
Kp 0.3
So 0.6
Sw 0.4
Sg 0
Hef 6.1
Rw 0.1
Ppl 5.6
Vu 0.0083
Bt 7.45
Cs 1.02
Kft 1.06
Skin 0.72
Kpezo 46.95
Khydro 0.65
$P_D = \frac{P_i - P_w}{P_i - P_D}$


Pressure Transient Analysis
Inverse problem
Changing WBS
Well:
Arbitrary
Reservoir:
Homogenious
Boundaries:
Infinite
Boundaries type:
Seal
Code
Value
Min
Max
Unit
Pi
4.642
0.46
46
MPa
Cs
1.02
0.102
10.2
m3/MPa
Kpr
73.62
3.724
372.4
md
Hef
6.1
0.61
61
m
Skin
-3.3
-5
2.72
n/a
Save
Apply
Inverse problem
Direct problem
Initial data
DP data
DP model
Pressure (MPa)
Time (hrs)
Production history
P fact
Q fact
P model
Pressure (MPa)
Flow rate (m3/d)
Time (hrs)
Model
Data
Production history